# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION
**Washington, D.C. 20549**

# FORM 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the Fiscal Year Ended December 31, 2017**

**OR**

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the Transition Period from to**

| Commission File Number | Registrant, State of Incorporation, Address and Telephone Number | I.R.S. Employer Identification No. |
|---|---|---|
| 1-3526 | **The Southern Company**<br>(A Delaware Corporation)<br>30 Ivan Allen Jr. Boulevard, N.W.<br>Atlanta, Georgia 30308<br>(404) 506-5000 | 58-0690070 |
| 1-3164 | **Alabama Power Company**<br>(An Alabama Corporation)<br>600 North 18th Street<br>Birmingham, Alabama 35291<br>(205) 257-1000 | 63-0004250 |
| 1-6468 | **Georgia Power Company**<br>(A Georgia Corporation)<br>241 Ralph McGill Boulevard, N.E.<br>Atlanta, Georgia 30308<br>(404) 506-6526 | 58-0257110 |
| 001-31737 | **Gulf Power Company**<br>(A Florida Corporation)<br>One Energy Place<br>Pensacola, Florida 32520<br>(850) 444-6111 | 59-0276810 |
| 001-11229 | **Mississippi Power Company**<br>(A Mississippi Corporation)<br>2992 West Beach Boulevard<br>Gulfport, Mississippi 39501<br>(228) 864-1211 | 64-0205820 |
| 001-37803 | **Southern Power Company**<br>(A Delaware Corporation)<br>30 Ivan Allen Jr. Boulevard, N.W.<br>Atlanta, Georgia 30308<br>(404) 506-5000 | 58-2598670 |
| 1-14174 | **Southern Company Gas**<br>(A Georgia Corporation)<br>Ten Peachtree Place, N.E.<br>Atlanta, Georgia 30309 | 58-2210952 |

(404) 584-4000

**Securities registered pursuant to Section 12(b) of the Act:** [(1)]

Each of the following classes or series of securities registered pursuant to Section 12(b) of the Act is listed on the New York Stock Exchange.

| Title of each class | Registrant |
|---|---|
| **Common Stock, $5 par value** | **The Southern Company** |
| **Junior Subordinated Notes, $25 denominations**<br>6.25% Series 2015A due 2075<br>5.25% Series 2016A due 2076<br>5.25% Series 2017B due 2077 | |
| **Class A preferred stock, cumulative, $25 stated capital**<br>5.00% Series | **Alabama Power Company** |
| **Junior Subordinated Notes, $25 denominations**<br>5.00% Series 2017A due 2077 | **Georgia Power Company** |
| **Depositary preferred shares, each representing one-fourth of a share of preferred stock, cumulative, $100 par value**<br>5.25% Series | **Mississippi Power Company** |
| **Senior Notes**<br>1.000% Series 2016A due 2022<br>1.850% Series 2016B due 2026 | **Southern Power Company** |

**Securities registered pursuant to Section 12(g) of the Act:** [(1)]

| Title of each class | | | Registrant |
|---|---|---|---|
| **Preferred stock, cumulative, $100 par value** | | | **Alabama Power Company** |
| 4.20% Series | 4.60% Series | 4.72% Series | |
| 4.52% Series | 4.64% Series | 4.92% Series | |
| **Preferred stock, cumulative, $100 par value** | | | **Mississippi Power Company** |
| 4.40% Series | 4.60% Series | | |
| 4.72% Series | | | |

(1) As of December 31, 2017.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

| Registrant | Yes | No |
|---|---|---|
| The Southern Company | X | |
| Alabama Power Company | X | |
| Georgia Power Company | X | |
| Gulf Power Company | | X |
| Mississippi Power Company | | X |
| Southern Power Company | X | |
| Southern Company Gas | X | |

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒ (Response applicable to all registrants.)

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

| Registrant | Large Accelerated Filer | Accelerated Filer | Non-accelerated Filer | Smaller Reporting Company | Emerging Growth Company |
|---|---|---|---|---|---|
| The Southern Company | X | | | | |
| Alabama Power Company | | | X | | |
| Georgia Power Company | | | X | | |
| Gulf Power Company | | | X | | |
| Mississippi Power Company | | | X | | |
| Southern Power Company | | | X | | |
| Southern Company Gas | | | X | | |

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒ (Response applicable to all registrants.)

Aggregate market value of The Southern Company's common stock held by non-affiliates of The Southern Company at June 30, 2017: $47.9 billion . All of the common stock of the other registrants is held by The Southern Company. A description of each registrant's common stock follows:

| **Registrant** | **Description of Common Stock** | **Shares Outstanding at January 31, 2018** |
|---|---|---|
| The Southern Company | Par Value $5 Per Share | 1,008,159,482 |
| Alabama Power Company | Par Value $40 Per Share | 30,537,500 |
| Georgia Power Company | Without Par Value | 9,261,500 |
| Gulf Power Company | Without Par Value | 7,392,717 |
| Mississippi Power Company | Without Par Value | 1,121,000 |
| Southern Power Company | Par Value $0.01 Per Share | 1,000 |
| Southern Company Gas | Par Value $0.01 Per Share | 100 |

Documents incorporated by reference: specified portions of The Southern Company's Definitive Proxy Statement on Schedule 14A relating to the 2018 Annual Meeting of Stockholders are incorporated by reference into PART III. In addition, specified portions of the Definitive Information Statements on Schedule 14C of Alabama Power Company and Mississippi Power Company relating to each of their respective 2018 Annual Meetings of Shareholders are incorporated by reference into PART III.

Each of Georgia Power Company, Gulf Power Company, Southern Power Company, and Southern Company Gas meets the conditions set forth in General Instructions I(1)(a) and (b) of Form 10-K and is therefore filing this Form 10-K with the reduced disclosure format specified in General Instructions I(2)(b), (c), and (d) of Form 10-K.

This combined Form 10-K is separately filed by The Southern Company, Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, Southern Power Company, and Southern Company Gas. Information contained herein relating to any individual company is filed by such company on its own behalf. Each company makes no representation as to information relating to the other companies.

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## DEFINITIONS

When used in Items 1 through 5 and Items 9A through 15, the following terms will have the meanings indicated.

| Term | Meaning |
|---|---|
| Alabama Power | Alabama Power Company |
| Bcf | Billion cubic feet |
| CCR | Coal combustion residuals |
| Clean Air Act | Clean Air Act Amendments of 1990 |
| $CO_2$ | Carbon dioxide |
| Cooperative Energy | Electric cooperative in Mississippi |
| Dalton | City of Dalton, Georgia, an incorporated municipality in the State of Georgia, acting by and through its Board of Water, Light, and Sinking Fund Commissioners |
| DOE | U.S. Department of Energy |
| Duke Energy Florida | Duke Energy Florida, LLC |
| EMC | Electric membership corporation |
| EPA | U.S. Environmental Protection Agency |
| EPC Contractor | Westinghouse and its affiliate, WECTEC Global Project Services Inc.; the former engineering, procurement, and construction contractor for Plant Vogtle Units 3 and 4 |
| FERC | Federal Energy Regulatory Commission |
| FMPA | Florida Municipal Power Agency |
| Georgia Power | Georgia Power Company |
| Gulf Power | Gulf Power Company |
| IBEW | International Brotherhood of Electrical Workers |
| IGCC | Integrated coal gasification combined cycle, the technology originally approved for Mississippi Power's Kemper County energy facility (Plant Ratcliffe) |
| IIC | Intercompany Interchange Contract |
| Internal Revenue Code | Internal Revenue Code of 1986, as amended |
| IPP | Independent Power Producer |
| IRP | Integrated Resource Plan |
| KUA | Kissimmee Utility Authority |
| KW | Kilowatt |
| KWH | Kilowatt-hour |
| MEAG Power | Municipal Electric Authority of Georgia |
| Merger | The merger, effective July 1, 2016, of a wholly-owned, direct subsidiary of Southern Company with and into Southern Company Gas, with Southern Company Gas continuing as the surviving corporation and a wholly-owned, direct subsidiary of Southern Company |
| Mississippi Power | Mississippi Power Company |
| MW | Megawatt |
| natural gas distribution utilities | Southern Company Gas' seven natural gas distribution utilities (Nicor Gas, Atlanta Gas Light Company, Virginia Natural Gas, Elizabethtown Gas, Florida City Gas, Chattanooga Gas Company, and Elkton Gas) |
| Nicor Gas | Northern Illinois Gas Company, a wholly-owned subsidiary of Southern Company Gas |
| NRC | U.S. Nuclear Regulatory Commission |
| NYSE | New York Stock Exchange |
| OPC | Oglethorpe Power Corporation (an Electric Membership Corporation) |
| OUC | Orlando Utilities Commission |

**DEFINITIONS**
(continued)

| Term | Meaning |
|---|---|
| PATH Act | Protecting Americans from Tax Hikes Act |
| Plant Vogtle Units 3 and 4 | Two new nuclear generating units under construction at Georgia Power's Plant Vogtle |
| power pool | The operating arrangement whereby the integrated generating resources of the traditional electric operating companies and Southern Power (excluding subsidiaries) are subject to joint commitment and dispatch in order to serve their combined load obligations |
| PowerSecure | PowerSecure Inc. |
| PowerSouth | PowerSouth Energy Cooperative |
| PPA | Power purchase agreements, as well as, for Southern Power, contracts for differences that provide the owner of a renewable facility a certain fixed price for the electricity sold to the grid |
| PSC | Public Service Commission |
| registrants | Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and Southern Company Gas |
| RUS | Rural Utilities Service |
| SCS | Southern Company Services, Inc. (the Southern Company system service company) |
| SEC | Securities and Exchange Commission |
| SEGCO | Southern Electric Generating Company |
| SEPA | Southeastern Power Administration |
| SERC | Southeastern Electric Reliability Council |
| Southern Company | The Southern Company |
| Southern Company Gas | Southern Company Gas and its subsidiaries |
| Southern Company Gas Capital | Southern Company Gas Capital Corporation, a 100%-owned subsidiary of Southern Company Gas |
| Southern Company system | Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), SEGCO, Southern Nuclear, SCS, Southern Linc, PowerSecure (as of May 9, 2016), and other subsidiaries |
| Southern Holdings | Southern Company Holdings, Inc. |
| Southern Linc | Southern Communications Services, Inc. |
| Southern Nuclear | Southern Nuclear Operating Company, Inc. |
| Southern Power | Southern Power Company and its subsidiaries |
| Tax Reform Legislation | The Tax Cuts and Jobs Act, which was signed into law on December 22, 2017 and became effective on January 1, 2018 |
| traditional electric operating companies | Alabama Power, Georgia Power, Gulf Power, and Mississippi Power |
| Virginia Natural Gas | Virginia Natural Gas, Inc. |
| Vogtle Owners | Georgia Power, OPC, MEAG Power, and Dalton |
| Westinghouse | Westinghouse Electric Company LLC |

**CAUTIONARY STATEMENT REGARDING**
**FORWARD-LOOKING INFORMATION**

This Annual Report on Form 10-K contains forward-looking statements. Forward-looking statements include, among other things, statements concerning regulated rates, the strategic goals for the wholesale business, customer and sales growth, economic conditions, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, pending or potential litigation matters, access to sources of capital, projections for the qualified pension plan s, postretirement benefit plans, and nuclear decommissioning trust fund contributions, financing activities, completion dates of construction projects, completion of announced acquisitions or dispositions, filings with state and federal regulatory authorities, impacts of the Tax Reform Legislation, federal and state income tax benefits, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including environmental laws and regulations governing air, water, land, and protection of other natural resources , and also changes in tax and other laws and regulations to which Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- the uncertainty surrounding the recently enacted Tax Reform Legislation, including implementing regulations and IRS interpretations, actions that may be taken in response by regulatory authorities, and its impact, if any, on the credit ratings of Southern Company and its subsidiaries;
- current and future litigation or regulatory investigations, proceedings, or inquiries ;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate;
- variations in demand for electricity and natural gas, including those relating to weather, the general economy, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of natural gas and other fuels;
- limits on pipeline capacity;
- transmission constraints;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development , construction, and operation of facilities, which include the development and construction of generating facilities with designs that have not been previously constructed, including changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor , contractor or supplier delay, non-performance under construction, operating, or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance ;
- the ability to construct facilities in accordance with the requirements of permits and licenses (including satisfaction of NRC requirements), to satisfy any environmental performance standards and the requirements of tax credits and other incentives , and to integrate facilities into the Southern Company system upon completion of construction;
- investment performance of the Southern Company system's employee and retiree benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- ongoing renewable energy partnerships and development agreements;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;

- the ability to successfully operate the electric utilities' generating, transmission, and distribution facilities and Southern Company Gas' natural gas distribution and storage facilities and the successful performance of necessary corporate functions ;
- legal proceedings and regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions;
- litigation related to the Kemper County energy facility;
- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, and financial risks;
- the inherent risks involved in transporting and storing natural gas;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, including the proposed disposition by a wholly-owned subsidiary of Southern Company Gas of Elizabethtown Gas and Elkton Gas and the potential sale of a 33% equity interest in substantially all of Southern Power's solar assets, which cannot be assured to be completed or beneficial to Southern Company or its subsidiaries;
- the possibility that the anticipated benefits from the Merger cannot be fully realized or may take longer to realize than expected and the possibility that costs related to the integration of Southern Company and Southern Company Gas will be greater than expected;
- the ability of counterparties of Southern Company and its subsidiaries to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Southern Company system's business resulting from cyber intrusion or physical attack and the threat of physical attacks;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in Southern Company's and any of its subsidiaries' credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on foreign currency exchange rates, counterparty performance, and the economy in general , as well as potential impacts on the benefits of the DOE loan guarantees;
- the ability of Southern Company's electric utilities to obtain additional generating capacity (or sell excess generating capacity) at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Southern Company system's business resulting from incidents affecting the U.S. electric grid , natural gas pipeline infrastructure , or operation of generating or storage resources;
- impairments of goodwill or long-lived assets;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports filed by the registrants from time to time with the SEC.

**The registrants expressly disclaim any obligation to update any forward-looking statements.**

# PART I

## Item 1. BUSINESS

Southern Company was incorporated under the laws of Delaware on November 9, 1945. Southern Company owns all of the outstanding common stock of Alabama Power, Georgia Power, Gulf Power, and Mississippi Power, each of which is an operating public utility company. The traditional electric operating companies supply electric service in the states of Alabama, Georgia, Florida, and Mississippi. More particular information relating to each of the traditional electric operating companies is as follows:

*Alabama Power* is a corporation organized under the laws of the State of Alabama on November 10, 1927, by the consolidation of a predecessor Alabama Power Company, Gulf Electric Company, and Houston Power Company. The predecessor Alabama Power Company had been in continuous existence since its incorporation in 1906.

*Georgia Power* was incorporated under the laws of the State of Georgia on June 26, 1930.

*Gulf Power* is a Florida corporation that has had a continuous existence since it was originally organized under the laws of the State of Maine on November 2, 1925. Gulf Power became a Florida corporation after being domesticated under the laws of the State of Florida on November 2, 2005.

*Mississippi Power* was incorporated under the laws of the State of Mississippi on July 12, 1972 and effective December 21, 1972, by the merger into it of the predecessor Mississippi Power Company, succeeded to the business and properties of the latter company. The predecessor Mississippi Power Company was incorporated under the laws of the State of Maine on November 24, 1924.

In addition, Southern Company owns all of the common stock of Southern Power Company, which is also an operating public utility company. Southern Power develops, constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Power Company is a corporation organized under the laws of Delaware on January 8, 2001. The term "Southern Power" when used herein refers to Southern Power Company and its subsidiaries while the term "Southern Power Company" when used herein refers only to the parent company.

Southern Company Gas, which was acquired by Southern Company in July 2016, is an energy services holding company whose primary business is the distribution of natural gas in seven states - Illinois, Georgia, Virginia, New Jersey, Florida, Tennessee, and Maryland - through the natural gas distribution utilities. Southern Company Gas is also involved in several other businesses that are complementary to the distribution of natural gas. Southern Company Gas was incorporated under the laws of the State of Georgia on November 27, 1995 for the primary purpose of becoming the holding company for Atlanta Gas Light Company, which was founded in 1856. See "The Southern Company System – Southern Company Gas" herein for additional information regarding agreements entered into by a wholly-owned subsidiary of Southern Company Gas to sell two of its natural gas distribution utilities.

Southern Company also owns all of the outstanding common stock or membership interests of SCS, Southern Linc, Southern Holdings, Southern Nuclear, PowerSecure, and other direct and indirect subsidiaries. SCS, the system service company, has contracted with Southern Company, each traditional electric operating company, Southern Power, Southern Company Gas, Southern Nuclear, SEGCO, and other subsidiaries to furnish, at direct or allocated cost and upon request, the following services: general executive and advisory, general and design engineering, operations, purchasing, accounting, finance and treasury, legal, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communication, and other services with respect to business and operations, construction management, and power pool transactions. Southern Linc provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber optics services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases and energy-related funds and companies, and for other electric and natural gas products and services. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants and is currently managing construction of and developing Plant Vogtle Units 3 and 4, which are co-owned by Georgia Power. PowerSecure is a provider of products and services in the areas of distributed generation infrastructure, energy efficiency, and utility infrastructure.

Alabama Power and Georgia Power each own 50% of the outstanding common stock of SEGCO. SEGCO is an operating public utility company that owns electric generating units with an aggregate capacity of 1,020 MWs at Plant Gaston on the Coosa River near Wilsonville, Alabama. Alabama Power and Georgia Power are each entitled to one-half of SEGCO's capacity and energy. Alabama Power acts as SEGCO's agent in the operation of SEGCO's units and furnishes fuel to SEGCO for its units.

Segment information for Southern Company and Southern Company Gas is included in Note 13 to the financial statements of Southern Company and Note 12 to the financial statements of Southern Company Gas in Item 8 herein.

The registrants' Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and any amendments to those reports are made available on Southern Company's website, free of charge, as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC. Southern Company's internet address is www.southerncompany.com.

**The Southern Company System**

***Traditional Electric Operating Companies***

The traditional electric operating companies are vertically integrated utilities that own generation, transmission, and distribution facilities. See PROPERTIES in Item 2 herein for additional information on the traditional electric operating companies' generating facilities. Each company's transmission facilities are connected to the respective company's own generating plants and other sources of power (including certain generating plants owned by Southern Power) and are interconnected with the transmission facilities of the other traditional electric operating companies and SEGCO. For information on the State of Georgia's integrated transmission system, see "Territory Served by the Southern Company System – Traditional Electric Operating Companies and Southern Power" herein.

Agreements in effect with principal neighboring utility systems provide for capacity and energy transactions that may be entered into from time to time for reasons related to reliability or economics. Additionally, the traditional electric operating companies have entered into voluntary reliability agreements with the subsidiaries of Entergy Corporation, Florida Electric Power Coordinating Group, and Tennessee Valley Authority and with Duke Energy Progress, LLC, Duke Energy Carolinas, LLC, South Carolina Electric & Gas Company, and Virginia Electric and Power Company, each of which provides for the establishment and periodic review of principles and procedures for planning and operation of generation and transmission facilities, maintenance schedules, load retention programs, emergency operations, and other matters affecting the reliability of bulk power supply. The traditional electric operating companies have joined with other utilities in the Southeast (including some of those referred to above) to form the SERC to augment further the reliability and adequacy of bulk power supply. Through the SERC, the traditional electric operating companies are represented on the National Electric Reliability Council.

The utility assets of the traditional electric operating companies and certain utility assets of Southern Power Company are operated as a single integrated electric system, or power pool, pursuant to the IIC. Activities under the IIC are administered by SCS, which acts as agent for the traditional electric operating companies and Southern Power Company. The fundamental purpose of the power pool is to provide for the coordinated operation of the electric facilities in an effort to achieve the maximum possible economies consistent with the highest practicable reliability of service. Subject to service requirements and other operating limitations, system resources are committed and controlled through the application of centralized economic dispatch. Under the IIC, each traditional electric operating company and Southern Power Company retains its lowest cost energy resources for the benefit of its own customers and delivers any excess energy to the power pool for use in serving customers of other traditional electric operating companies or Southern Power Company or for sale by the power pool to third parties. The IIC provides for the recovery of specified costs associated with the affiliated operations thereunder, as well as the proportionate sharing of costs and revenues resulting from power pool transactions with third parties.

Southern Power and Southern Linc have secured from the traditional electric operating companies certain services which are furnished at cost in compliance with FERC regulations.

Alabama Power and Georgia Power each have agreements with Southern Nuclear to operate the Southern Company system's existing nuclear plants, Plants Farley, Hatch, and Vogtle. In addition, Georgia Power has an agreement with Southern Nuclear to develop, license, construct, and operate Plant Vogtle Units 3 and 4. See "Regulation – Nuclear Regulation" herein for additional information.

***Southern Power***

Southern Power develops, constructs, acquires, owns, and manages power generation assets, including renewable energy facilities, and sells electricity at market-based rates (under authority from the FERC) in the wholesale market. Southern Power continually seeks opportunities to execute its strategy to create value through various transactions including acquisitions and sales of assets, development and construction of new generating facilities, and entry into PPAs primarily with investor-owned utilities, IPPs, municipalities, electric cooperatives, and other load-serving entities, as well as commercial and industrial customers. Southern Power's business activities are not subject to traditional state regulation like the traditional electric operating companies, but the majority of its business activities are subject to regulation by the FERC. Southern Power has attempted to insulate itself from significant fuel supply, fuel transportation, and electric transmission risks by generally making such risks the responsibility of the counterparties to its PPAs. However, Southern Power's future earnings will depend on the parameters of the wholesale market and the efficient operation of its wholesale generating assets, as well as Southern Power's ability to execute its growth strategy and to develop and construct generating facilities. For additional information on Southern Power's business activities, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Business Activities" of Southern Power in Item 7 herein.

Southern Power Company directly owns and manages generation assets primarily in the Southeast, which are included in the power pool, and has various subsidiaries, which were created to own and operate natural gas and renewable generation facilities either wholly or in partnership with various third parties. As of December 31, 2017 , Southern Power's generation fleet totaled 12,940 MWs of nameplate capacity in commercial operation (including 5,152 MWs owned by its subsidiaries). In addition, Southern Power Company has other subsidiaries that are pursuing additional natural gas generation and other development opportunities. The generation assets of Southern Power Company's subsidiaries are not included in the power pool.

Some of Southern Power's partnerships allow for the sharing of cash distributions and tax benefits at differing percentages. Southern Power is entitled to 51% of all cash distributions from eight of the partnership entities and the respective partner who holds the class B membership interests is entitled to 49% of all cash distributions. For the Desert Stateline partnership, Southern Power is entitled to 66% of all cash distributions and the class B member is entitled to 34% of all cash distributions. In addition, Southern Power is entitled to substantially all of the federal tax benefits with respect to these nine partnership entities.

In September 2017 , Southern Power began a legal entity reorganization of various direct and indirect subsidiaries that own and operate substantially all of the solar facilities, including certain subsidiaries owned in partnership with various third parties. The reorganization is expected to be substantially completed in the first quarter 2018. Southern Power is pursuing the sale of a 33% equity interest in the newly-formed holding company owning these solar assets, which, if successful, is expected to close in the middle of 2018. The ultimate outcome of this matter cannot be determined at this time.

See PROPERTIES in Item 2 herein, Note 11 to the financial statements of Southern Power in Item 8 herein, and Note 12 to the financial statements of Southern Company under "Southern Power" in Item 8 herein for additional information regarding Southern Power's acquisitions, construction, and development projects.

Southern Power calculates an investment coverage ratio for its generating assets based on the ratio of investment under contract to total investment using the respective generation facilities' net book value (or expected in-service value for facilities under construction or being acquired) as the investment amount. With the inclusion of the PPAs and investments associated with the wind and natural-gas fired facilities currently under construction and the Gaskell West 1 solar project, which was acquired subsequent to December 31, 2017 , as well as other capacity and energy contracts, Southern Power has an average investment coverage ratio of 91 % through 2022 and 89 % through 2027, with an average remaining contract duration of approximately 15 years.

Southern Power's natural gas and biomass sales are primarily through long-term PPAs that consist of two types of agreements. The first type, referred to as a unit or block sale, is a customer purchase from a dedicated plant unit where all or a portion of the generation from that unit is reserved for that customer. Southern Power typically has the ability to serve the unit or block sale customer from an alternate resource. The second type, referred to as requirements service, provides that Southern Power serves the customer's capacity and energy requirements from a combination of the customer's own generating units and from Southern Power resources not dedicated to serve unit or block sales. Southern Power has rights to purchase power provided by the requirements customers' resources when economically viable. Capacity charges that form part of the PPA payments are designed to recover fixed and variable operations and maintenance costs based on dollars-per-kilowatt year and to provide a return on investment.

Southern Power's electricity sales from solar and wind generating facilities are predominantly through long-term PPAs; however, these solar and wind PPAs do not have a capacity charge and customers either purchase the energy output of a dedicated renewable facility through an energy charge or provide Southern Power a certain fixed price for the electricity sold to the grid. As a result, Southern Power's ability to recover fixed and variable operations and maintenance expenses is dependent upon the level of energy generated from these facilities, which can be impacted by weather conditions, equipment performance, transmission constraints, and other factors.

The following tables set forth Southern Power's PPAs as of December 31, 2017:

*Block Sales PPAs*

| Facility/Source | Counterparty | MWs [1] | Contract Term |
|---|---|---|---|
| Addison Units 1 and 3 | Georgia Power | 297 | through May 2030 |
| Addison Unit 2 | MEAG Power | 149 | through April 2029 |
| Addison Unit 4 | Georgia Energy Cooperative | 146 | through May 2030 |
| Cleveland County Unit 1 | North Carolina Electric Membership Corporation (NCEMC) | 45-180 | through Dec. 2036 |
| Cleveland County Unit 2 | NCEMC | 183 | through Dec. 2036 |
| Cleveland County Unit 3 | North Carolina Municipal Power Agency 1 | 183 | through Dec. 2031 |
| Cleveland County Unit 4 | PJM Interconnection LLC [2] | 183 | June 2020 – May 2021 |
| Dahlberg Units 1, 3, and 5 | Cobb EMC | 224 | through Dec. 2026 |
| Dahlberg Units 2, 6, 8, and 10 | Georgia Power | 298 | through May 2025 |
| Dahlberg Unit 4 | Georgia Power | 74 | through May 2030 |
| Franklin Unit 1 | Duke Energy Florida | 434 | through May 2021 |
| Franklin Unit 2 | Morgan Stanley Capital Group | 250 | through Dec. 2025 |
| Franklin Unit 2 | Jackson EMC | 60-65 | through Dec. 2035 |
| Franklin Unit 2 | GreyStone Power Corporation | 35-40 | through Dec. 2035 |
| Franklin Unit 2 | Cobb EMC | 100 | through Dec. 2026 |
| Franklin Unit 3 | Morgan Stanley Capital Group | 200 | through Dec. 2027 |
| Franklin Unit 3 | City of Dalton, Georgia | 70 | through Dec. 2027 |
| Harris Unit 1 | Georgia Power | 628 | through May 2030 |
| Harris Unit 2 | Georgia Power | 657 | through May 2019 |
| Harris Unit 2 | Alabama Municipal Electric Authority [3] | 25 | Jan. 2020 – Dec. 2025 |
| Mankato | Northern States Power Company | 375 | through June 2026 |
| Mankato | Northern States Power Company | 345 | June 2019 – May 2039 [4] |
| Nacogdoches | City of Austin, Texas | 100 | through May 2032 |
| NCEMC PPA [5] | EnergyUnited | 100 | through Dec. 2021 |
| Oleander Units 2, 3, and 4 | Seminole Electric Cooperative | 466 | through Dec. 2021 |
| Oleander Unit 5 | FMPA | 157 | through Dec. 2027 |
| Rowan CT Unit 1 | North Carolina Municipal Power Agency 1 | 150 | through Dec. 2030 |
| Rowan CT Unit 2 | PJM Interconnection LLC [2] | 154 | June 2020 – May 2021 |
| Rowan CT Units 2 and 3 | EnergyUnited | 100-175 | Jan. 2022 – Dec. 2025 |
| Rowan CT Unit 3 | EnergyUnited | 113 | through Dec. 2023 |
| Rowan CC Unit 4 | EnergyUnited | 23-328 | through Dec. 2025 |

*Block Sales PPAs (continued)*

| Facility/Source | Counterparty | MWs [1] | Contract Term |
|---|---|---|---|
| Rowan CC Unit 4 | Duke Energy Progress, LLC | 150 | through Dec. 2019 |
| Rowan CC Unit 4 | Century Aluminum [6] | 158 | through Dec. 2018 |
| Stanton Unit A | OUC | 342 | through Sept. 2033 |
| Stanton Unit A | FMPA | 85 | through Sept. 2033 |
| Wansley Unit 7 | Jacksonville Electric Authority | 200 | through Dec. 2019 |

(1) The MWs and related facility units may change due to unit rating changes or assignment of units to contracts.
(2) Amount sold into PJM capacity market.
(3) Alabama Municipal Electric Authority will also be served by Plant Franklin Unit 1 through December 2019.
(4) Subject to commercial operation of the 345-MW expansion project.
(5) Represents sale of power purchased from NCEMC under a PPA.
(6) Century Aluminum PPA is partially served by Plant Franklin Unit 3.

*Requirements Services PPAs*

| Counterparty | MWs [1] | Contract Term |
|---|---|---|
| Nine Georgia EMCs | 294-376 | through Dec. 2024 |
| Sawnee EMC | 267-639 | through Dec. 2027 |
| Cobb EMC | 0-170 | through Dec. 2026 |
| Flint EMC | 136-360 | through Dec. 2024 |
| City of Dalton, Georgia | 92 | through Dec. 2027 |
| EnergyUnited | 78-159 | through Dec. 2025 |
| City of Blountstown, Florida | 10 | through April 2022 |

(1) Represents forecasted incremental capacity needs over the contract term.

*Solar/Wind PPAs*

| Facility | Counterparty | MWs [1] | Contract Term |
|---|---|---|---|
| ***Solar*** | | | |
| Adobe | Southern California Edison Company | 20 | through June 2034 |
| Apex | Nevada Power Company | 20 | through Dec. 2037 |
| Boulder 1 [2] | Nevada Power Company | 100 | through Dec. 2036 |
| Butler | Georgia Power | 100 | through Dec. 2046 |
| Butler Solar Farm | Georgia Power | 20 | through Feb. 2036 |
| Calipatria | San Diego Gas & Electric Company | 20 | through Feb. 2036 |
| Campo Verde | San Diego Gas & Electric Company | 139 | through Oct. 2033 |
| Cimarron | Tri-State Generation and Transmission Association, Inc. | 30 | through Dec. 2035 |
| Decatur County | Georgia Power | 19 | through Dec. 2035 |
| Decatur Parkway | Georgia Power | 80 | through Dec. 2040 |
| Desert Stateline [2] | Southern California Edison Company | 300 | through Sept. 2036 |
| East Pecos | Austin Energy | 119 | through April 2032 |
| Garland A [2] | Southern California Edison Company | 20 | through Sept. 2036 |
| Garland [2] | Southern California Edison Company | 180 | through Oct. 2031 |
| Granville | Duke Energy Progress, LLC | 2 | through Oct. 2032 |
| Henrietta [2] | Pacific Gas & Electric Company | 100 | through Sept. 2036 |
| Imperial Valley [2] | San Diego Gas & Electric Company | 150 | through Nov. 2039 |

*Solar/Wind PPAs (continued)*

| Facility | Counterparty | MWs [1] | Contract Term |
|---|---|---|---|
| Lamesa | City of Garland, Texas | 102 | through April 2032 |
| Lost Hills Blackwell [2] | City of Roseville, California & Pacific Gas & Electric Company | 32 | through Dec. 2043 |
| Macho Springs | El Paso Electric Company | 50 | through May 2034 |
| Morelos | Pacific Gas & Electric Company | 15 | through Feb. 2036 |
| North Star [2] | Pacific Gas & Electric Company | 60 | through June 2035 |
| Pawpaw | Georgia Power | 30 | through March 2046 |
| Roserock [2] | Austin Energy | 157 | through Nov. 2036 |
| Rutherford | Duke Energy Carolinas, LLC | 75 | through Dec. 2031 |
| Sandhills | Cobb EMC | 111 | through Oct. 2041 |
| Sandhills | Flint EMC | 15 | through Oct. 2041 |
| Sandhills | Sawnee EMC | 15 | through Oct. 2041 |
| Sandhills | Middle Georgia and Irwin EMC | 2 | through Oct. 2041 |
| Spectrum | Nevada Power Company | 30 | through Dec. 2038 |
| Tranquillity [2] | Shell Energy North America (US), LP | 204 | through Nov. 2019 |
| Tranquillity [2] | Southern California Edison Company | 204 | Dec. 2019 – Nov. 2034 |
| ***Wind*** | | | |
| Bethel | Google Inc. | 225 | through Jan. 2029 |
| Cactus Flats [3] | General Mills, Inc. | 98 | Aug. 2018 – July 2034 |
| Cactus Flats [3] | General Motors Company | 50 | Aug. 2018 – July 2031 |
| Grant Plains | Oklahoma Municipal Power Authority | 41 | Jan. 2020 – Dec. 2039 |
| Grant Plains | Steelcase Inc. | 25 | through Dec. 2028 |
| Grant Plains | Allianz Risk Transfer (Bermuda) Ltd. | 81-122 | through March 2027 |
| Grant Wind | East Texas Electric Cooperative | 50 | through March 2036 |
| Grant Wind | Northeast Texas Electric Cooperative | 50 | through March 2036 |
| Grant Wind | Western Farmers Electric Cooperative | 50 | through March 2036 |
| Kay Wind | Westar Energy Inc. | 200 | through Dec. 2035 |
| Kay Wind | Grand River Dam Authority | 99 | through Dec. 2035 |
| Passadumkeag | Western Massachusetts Electric Company | 40 | through June 2031 |
| Salt Fork Wind | City of Garland, Texas | 150 | through Nov. 2030 |
| Salt Fork Wind | Salesforce.com, Inc. | 24 | through Nov. 2028 |
| Tyler Bluff Wind | The Proctor & Gamble Company | 96 | through Dec. 2028 |
| Wake Wind [2] | Equinix Enterprises, Inc. | 100 | through Oct. 2028 |
| Wake Wind [2] | Owens Corning | 125 | through Oct. 2028 |

(1) MWs shown are for 100% of the PPA, which is based on demonstrated capacity of the facility.
(2) Facility is the subject of a partnership where Southern Power is the majority member. See PROPERTIES in Item 2 herein for additional information.
(3) Subject to commercial operation.

*Purchased Power*

| Facility/Source | Counterparty | MWs | Contract Term |
|---|---|---|---|
| NCEMC | NCEMC | 100 | through Dec. 2021 |

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" and "Acquisitions" of Southern Power in Item 7 herein and Note 11 to the financial statements of Southern Power in Item 8 herein for additional information.

For the year ended December 31, 2017 , approximately 11.3% of Southern Power's revenues were derived from Georgia Power. Southern Power actively pursues replacement PPAs prior to the expiration of its current PPAs and anticipates that the revenues attributable to one customer may be replaced by revenues from a new customer; however, the expiration of any of Southern Power's current PPAs without the successful remarketing of a replacement PPA could have a material negative impact on Southern Power's earnings but is not expected to have a material impact on Southern Company's earnings.

***Southern Company Gas***

Southern Company Gas is an energy services holding company whose primary business is the distribution of natural gas through the natural gas distribution utilities. Southern Company Gas is also involved in several other businesses that are complementary to the distribution of natural gas, including gas marketing services, wholesale gas services, and gas midstream operations.

Gas distribution operations, the largest segment of Southern Company Gas' business, operates, constructs, and maintains 82,000 miles of natural gas pipelines and 14 storage facilities, with total capacity of 158 Bcf, to provide natural gas to residential, commercial, and industrial customers. Gas distribution operations serves approximately 4.6 million customers across seven states and has rates of return that are regulated by each individual state in return for exclusive franchises.

On October 15, 2017, Southern Company Gas subsidiary, Pivotal Utility Holdings Inc., entered into agreements for the sale of the assets of two of its natural gas distribution utilities, Elizabethtown Gas and Elkton Gas, to South Jersey Industries, Inc. for a total cash purchase price of $1.7 billion. As of December 31, 2017, the net book value of the assets to be disposed of in the sale was approximately $1.3 billion, which includes approximately $0.5 billion of goodwill. The goodwill is not deductible for tax purposes and, as a result, a deferred tax liability has not yet been provided. Through the completion of the asset sales, Southern Company Gas intends to invest less than $0.1 billion in capital additions required for ordinary business operations of these assets. The completion of each asset sale is subject to the satisfaction or waiver of certain conditions, including, among other customary closing conditions, the receipt of required regulatory approvals, including the FERC, the Federal Communications Commission, the New Jersey Board of Public Utilities, and, with respect to the sale of Elkton Gas, the Maryland PSC. Southern Company Gas and South Jersey Industries, Inc. made joint filings on December 22, 2017 and January 16, 2018 with the New Jersey Board of Public Utilities and the Maryland PSC, respectively, requesting regulatory approval. The asset sales are expected to be completed by the end of the third quarter 2018. The ultimate outcome of these matters cannot be determined at this time.

Gas marketing services is comprised of SouthStar Energy Services, LLC (SouthStar) and Nicor Energy Services Company (doing business as Pivotal Home Solutions) and provides natural gas commodity and related services to customers in competitive markets or markets that provide for customer choice. SouthStar, serving approximately 774,000 natural gas commodity customers, markets gas to residential, commercial, and industrial customers and offers energy-related products that provide natural gas price stability and utility bill management. Pivotal Home Solutions, serving approximately 1.2 million service contracts, provides a suite of home protection products and services that offers homeowners predictability regarding their energy service delivery, systems, and appliances.

Wholesale gas services consists of Sequent Energy Management, L.P. and engages in natural gas storage and gas pipeline arbitrage and provides natural gas asset management and related logistical services to most of the natural gas distribution utilities as well as non-affiliate companies.

Gas midstream operations includes joint ventures in pipeline investments (including a 50% ownership interest in Southern Natural Gas Company, L.L.C. and two significant pipeline construction projects) as well as a 50% joint ownership in a significant pipeline project and wholly-owned natural gas storage facilities that enable the provision of diverse sources of natural gas supplies to the customers of Southern Company Gas. Southern Natural Gas Company, L.L.C. is the owner of a 7,000-mile pipeline connecting natural gas supply basins in Texas, Louisiana, Mississippi, and Alabama to markets in Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina, and Tennessee.
For additional information on Southern Company Gas' business activities, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Business Activities" and – FUTURE EARNINGS POTENTIAL of Southern Company Gas in Item 7 herein.

***Other Businesses***

PowerSecure, which was acquired by Southern Company in May 2016, provides products and services in the areas of distributed energy infrastructure, energy efficiency, and utility infrastructure.

Southern Holdings is an intermediate holding subsidiary, primarily for Southern Company's investments in leveraged leases and energy-related funds and companies, and also for other electric and natural gas products and services.

Southern Linc provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public. Southern Linc delivers multiple wireless communication options including push to talk, cellular service, text messaging, wireless internet access, and wireless data. Its system covers approximately 127,000 square miles in the Southeast. Southern Linc also provides fiber optics services within the Southeast through its subsidiary, Southern Telecom, Inc.

These efforts to invest in and develop new business opportunities may offer potential returns exceeding those of rate-regulated operations. However, these activities often involve a higher degree of risk.

**Construction Programs**

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. For estimated construction and environmental expenditures for the periods 2018 through 2022 , see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Southern Company, each traditional electric operating company, Southern Power, and Southern Company Gas in Item 7 herein. The Southern Company system's construction program consists of capital investment and capital expenditures to comply with environmental laws and regulations. The traditional electric operating companies also anticipate expenditures associated with ash pond closure and ground water monitoring under the Disposal of Coal Combustion Residuals from Electric Utilities rule (CCR Rule), which are reflected in the Southern Company system's asset retirement obligation liabilities. In 2018 , the construction program is expected to be apportioned approximately as follows:

| | Southern Company system [a][b] | Alabama Power | Georgia Power [a] | Gulf Power | Mississippi Power |
|---|---|---|---|---|---|
| | | | (in billions) | | |
| New generation | $ 1.3 | $ — | $ 1.3 | $ — | $ — |
| Environmental compliance [c] | 1.1 | 0.6 | 0.5 | 0.1 | — |
| Generation maintenance | 0.9 | 0.5 | 0.2 | 0.1 | 0.1 |
| Transmission | 0.9 | 0.3 | 0.5 | — | — |
| Distribution | 1.2 | 0.5 | 0.5 | 0.1 | 0.1 |
| Nuclear fuel | 0.3 | 0.1 | 0.2 | — | — |
| General plant | 0.5 | 0.2 | 0.2 | — | — |
| | 6.0 | 2.2 | 3.3 | 0.3 | 0.2 |
| Southern Power [d] | 1.3 | | | | |
| Southern Company Gas [e] | 1.7 | | | | |
| Other subsidiaries | 0.4 | | | | |
| Total [a] | $ 9.4 | $ 2.2 | $ 3.3 | $ 0.3 | $ 0.2 |

(a) Totals may not add due to rounding.

(b) Includes the traditional electric operating companies, Southern Power, and Southern Company Gas, as well as the other subsidiaries. See "Other Businesses" herein for additional information.

(c) Reflects cost estimates for environmental regulations. These estimated expenditures do not include any potential compliance costs associated with the regulation of $CO_2$ emissions from fossil-fuel-fired electric generating units or costs associated with closure and groundwater monitoring under the CCR Rule. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations" and FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Southern Company and each traditional electric operating company in Item 7 herein for additional information.

(d) Includes approximately $0.9 billion for planned expenditures for plant acquisitions and placeholder growth, which may vary materially due to market opportunities and Southern Power's ability to execute its growth strategy.

(e) Includes costs for ongoing capital projects associated with infrastructure improvement programs for certain natural gas distribution utilities that have been previously approved by their applicable state regulatory agencies. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Infrastructure Replacement Programs and Capital Projects" of Southern Company Gas in Item 7 herein for additional information. See

"The Southern Company System – Southern Company Gas" herein for additional information regarding agreements entered into by a wholly-owned subsidiary of Southern Company Gas to sell two of its natural gas distribution utilities. Projected capital expenditures of $0.1 billion related to these two natural gas distribution utilities are excluded from the amounts above.

The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental laws and regulations; the outcome of any legal challenges to the environmental rules; changes in electric generating plants, including unit retirements and replacements and adding or changing fuel sources at existing electric generating units, to meet regulatory requirements; changes in FERC rules and regulations; state regulatory agency approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. Additionally, planned expenditures for plant acquisitions may vary due to market opportunities and Southern Power's ability to execute its growth strategy.

In addition, the construction program includes the development and construction of new electric generating facilities with designs that have not been previously constructed, which may result in revised estimates during construction. See Note 3 to the financial statements of Southern Company and Georgia Power under "Nuclear Construction" and "Retail Regulatory Matters – Nuclear Construction," respectively, in Item 8 herein for additional information regarding Georgia Power's construction of Plant Vogtle Units 3 and 4.

Also see "Regulation – Environmental Laws and Regulations" herein for additional information with respect to certain existing and proposed environmental requirements and PROPERTIES – "Electric – Jointly-Owned Facilities" and – "Natural Gas – Jointly-Owned Facilities" in Item 2 herein for additional information concerning Alabama Power's, Georgia Power's, and Southern Power's joint ownership of certain generating units and related facilities with certain non-affiliated utilities and Southern Company Gas' joint ownership of a pipeline facility.

**Financing Programs**

See each of the registrant's MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY in Item 7 herein and Note 6 to the financial statements of each registrant in Item 8 herein for information concerning financing programs.

**Fuel Supply**

***Electric***

The traditional electric operating companies' and SEGCO's supply of electricity is primarily fueled by natural gas and coal. Southern Power's supply of electricity is primarily fueled by natural gas. See MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATION – "Electricity Business – Fuel and Purchased Power Expenses" of Southern Company and MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATION – "Fuel and Purchased Power Expenses" of each traditional electric operating company in Item 7 herein for information regarding the electricity generated and the average cost of fuel in cents per net KWH generated for the years 2015 through 2017 .

The traditional electric operating companies have agreements in place from which they expect to receive substantially all of their 2018 coal burn requirements. These agreements have terms ranging between one and four years. In 2017 , the weighted average sulfur content of all coal burned by the traditional electric operating companies was 1.12%. This sulfur level, along with banked and purchased sulfur dioxide allowances, allowed the traditional electric operating companies to remain within limits set by Phase I of the Cross-State Air Pollution Rule (CSAPR) under the Clean Air Act. In 2017 , the Southern Company system did not purchase any sulfur dioxide allowances, annual nitrogen oxide emission allowances, or seasonal nitrogen oxide emission allowances from the market. As any additional environmental regulations are proposed that impact the utilization of coal, the traditional electric operating companies' fuel mix will be monitored to help ensure that the traditional electric operating companies remain in compliance with applicable laws and regulations. Additionally, Southern Company and the traditional electric operating companies will continue to evaluate the need to purchase additional emissions allowances, the timing of capital expenditures for emissions control equipment, and potential unit retirements and replacements. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company, each traditional electric operating company, and Southern Power in Item 7 herein for additional information on environmental matters.

SCS, acting on behalf of the traditional electric operating companies and Southern Power Company, has agreements in place for the natural gas burn requirements of the Southern Company system. For 2018 , SCS has contracted for 510 Bcf of natural gas supply under agreements with remaining terms up to 15 years. In addition to natural gas supply, SCS has contracts in place for both firm natural gas transportation and storage. Management believes these contracts provide sufficient natural gas supplies, transportation, and storage to ensure normal operations of the Southern Company system's natural gas generating units.

Alabama Power and Georgia Power have multiple contracts covering their nuclear fuel needs for uranium, conversion services, enrichment services, and fuel fabrication. The uranium, conversion services, and fuel fabrication contracts are for terms of less than 10 years with varying expiration dates. The term lengths for the enrichment services contracts are for less than 15 years with varying expiration dates. Management believes suppliers have sufficient nuclear fuel production capability to permit the normal operation of the Southern Company system's nuclear generating units.

Changes in fuel prices to the traditional electric operating companies are generally reflected in fuel adjustment clauses contained in rate schedules. See "Rate Matters – Rate Structure and Cost Recovery Plans" herein for additional information. Southern Power's natural gas and biomass PPAs generally provide that the counterparty is responsible for substantially all of the cost of fuel.

Alabama Power and Georgia Power have contracts with the United States, acting through the DOE, that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent fuel in 1998, as required by the contracts, and Alabama Power and Georgia Power have pursued and are pursuing legal remedies against the government for breach of contract. See Note 3 to the financial statements of Southern Company, Alabama Power, and Georgia Power under "Nuclear Fuel Disposal Costs" in Item 8 herein for additional information.

***Natural Gas***

Recent advances in natural gas drilling in shale producing regions of the United States have resulted in historically high supplies of natural gas and relatively low prices for natural gas. Procurement plans for natural gas supply and transportation to serve regulated utility customers are reviewed and approved by the state regulatory agencies in which Southern Company Gas operates. Southern Company Gas purchases natural gas supplies in the open market by contracting with producers and marketers and from its wholly-owned subsidiary, Sequent Energy Management, L.P., under asset management agreements in states where such agreements are approved by the applicable state regulatory agency. Southern Company Gas also contracts for transportation and storage services from interstate pipelines that are regulated by the FERC. When firm pipeline services are temporarily not needed, Southern Company Gas may release the services in the secondary market under FERC-approved capacity release provisions or utilize asset management arrangements, thereby reducing the net cost of natural gas charged to customers for most of the natural gas distribution utilities. Peak-use requirements are met through utilization of company-owned storage facilities, pipeline transportation capacity, purchased storage services, peaking facilities, and other supply sources, arranged by either transportation customers or Southern Company Gas.

**Territory Served by the Southern Company System**

***Traditional Electric Operating Companies and Southern Power***

The territory in which the traditional electric operating companies provide retail electric service comprises most of the states of Alabama and Georgia, together with the northwestern portion of Florida and southeastern Mississippi. In this territory there are non-affiliated electric distribution systems that obtain some or all of their power requirements either directly or indirectly from the traditional electric operating companies. As of December 31, 2017 , the territory had an area of approximately 120,000 square miles and an estimated population of approximately 17 million. Southern Power sells electricity at market-based rates in the wholesale market, primarily to investor-owned utilities, IPPs, municipalities, and other load-serving entities, as well as commercial and industrial customers.

Alabama Power is engaged, within the State of Alabama, in the generation, transmission, distribution, and purchase of electricity and the sale of electric service, at retail in approximately 400 cities and towns (including Anniston, Birmingham, Gadsden, Mobile, Montgomery, and Tuscaloosa), as well as in rural areas, and at wholesale to 14 municipally-owned electric distribution systems, 11 of which are served indirectly through sales to the Alabama Municipal Electric Authority, and two rural distributing cooperative associations. Alabama Power owns coal reserves near its Plant Gorgas and uses the output of coal from the reserves in its generating plants. Alabama Power also sells, and cooperates with dealers in promoting the sale of, electric appliances and products and markets and sells outdoor lighting services.

Georgia Power is engaged in the generation, transmission, distribution, and purchase of electricity and the sale of electric service within the State of Georgia, at retail in over 600 communities (including Athens, Atlanta, Augusta, Columbus, Macon, Rome, and Savannah), as well as in rural areas, and at wholesale to OPC, MEAG Power, Dalton, various EMCs, and non-affiliated utilities. Georgia Power also markets and sells outdoor lighting services.

Gulf Power is engaged, within the northwestern portion of Florida, in the generation, transmission, distribution, and purchase of electricity and the sale of electric service, at retail in 71 communities (including Pensacola, Panama City, and Fort Walton Beach), as well as in rural areas, and at wholesale to a non-affiliated utility.

Mississippi Power is engaged in the generation, transmission, distribution, and purchase of electricity and the sale of electric service within 23 counties in southeastern Mississippi, at retail in 123 communities (including Biloxi, Gulfport, Hattiesburg, Laurel, Meridian, and Pascagoula), as well as in rural areas, and at wholesale to one municipality, six rural electric distribution cooperative associations, and one generating and transmitting cooperative.

For information relating to KWH sales by customer classification for the traditional electric operating companies, see MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATIONS of each traditional electric operating company in Item 7 herein. For information relating to the number of retail customers served by customer classification for the traditional electric operating companies, see SELECTED FINANCIAL DATA of each traditional electric operating company in Item 6 herein. Also, for information relating to the sources of revenues for Southern Company, each traditional electric operating company, and Southern Power, reference is made to Item 7 herein.

The RUS has authority to make loans to cooperative associations or corporations to enable them to provide electric service to customers in rural sections of the country. As of December 31, 2017 , there were approximately 62 electric cooperative distribution systems operating in the territory in which the traditional electric operating companies provide electric service at retail or wholesale.

One of these organizations, PowerSouth, is a generating and transmitting cooperative selling power to several distributing cooperatives, municipal systems, and other customers in south Alabama and northwest Florida. As of December 31, 2017 , PowerSouth owned generating units with approximately 2,100 MWs of nameplate capacity, including an undivided 8.16% ownership interest in Alabama Power's Plant Miller Units 1 and 2. PowerSouth's facilities were financed with RUS loans secured by long-term contracts requiring distributing cooperatives to take their requirements from PowerSouth to the extent such energy is available. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for details of Alabama Power's joint-ownership with PowerSouth of a portion of Plant Miller. Alabama Power has a system supply agreement with PowerSouth to provide 200 MWs of capacity service through December 31, 2030 with an option to extend and renegotiate in the event Alabama Power builds new generation or contracts for new capacity.

Alabama Power and Gulf Power have entered into separate agreements with PowerSouth involving interconnection between their respective systems. The delivery of capacity and energy from PowerSouth to certain distributing cooperatives in the service territories of Alabama Power and Gulf Power is governed by the Southern Company/PowerSouth Network Transmission Service Agreement. The rates for this service to PowerSouth are on file with the FERC.

OPC is an EMC owned by its 38 retail electric distribution cooperatives, which provide retail electric service to customers in Georgia. OPC provides wholesale electric power to its members through its generation assets and power purchased from other suppliers.

Four electric cooperative associations, financed by the RUS, operate within Gulf Power's service territory. These cooperatives purchase their full requirements from PowerSouth and SEPA (a federal power marketing agency). A non-affiliated utility also operates within Gulf Power's service territory and purchases its full requirements from Gulf Power.

Mississippi Power has an interchange agreement with Cooperative Energy, a generating and transmitting cooperative, pursuant to which various services are provided.

As of December 31, 2017 , there were approximately 72 municipally-owned electric distribution systems operating in the territory in which the traditional electric operating companies provide electric service at retail or wholesale.

As of December 31, 2017 , 48 municipally-owned electric distribution systems and one county-owned system received their requirements through MEAG Power, which was established by a Georgia state statute in 1975. MEAG Power serves these requirements from self-owned generation facilities, some of which are jointly-owned with Georgia Power, and purchases from other resources. MEAG Power also has a pseudo scheduling and services agreement with Georgia Power. Dalton serves its requirements from self-owned generation facilities, some of which are jointly-owned with Georgia Power, and through purchases from Georgia Power and Southern Power through a service agreement. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

Georgia Power has entered into substantially similar agreements with Georgia Transmission Corporation, MEAG Power, and Dalton providing for the establishment of an integrated transmission system to carry the power and energy of all parties. The agreements require an investment by each party in the integrated transmission system in proportion to its respective share of the aggregate system load. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

Southern Power assumed or entered into PPAs with some of the traditional electric operating companies, investor-owned utilities, IPPs, municipalities, electric cooperatives, and other load-serving entities, as well as commercial and industrial customers. See "The Southern Company System – Southern Power" above and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" of Southern Power in Item 7 herein for additional information concerning Southern Power's PPAs.

SCS, acting on behalf of the traditional electric operating companies, also has a contract with SEPA providing for the use of the traditional electric operating companies' facilities at government expense to deliver to certain cooperatives and municipalities, entitled by federal statute to preference in the purchase of power from SEPA, quantities of power equivalent to the amounts of power allocated to them by SEPA from certain U.S. government hydroelectric projects.

***Southern Company Gas***

Southern Company Gas is engaged in the distribution of natural gas in seven states through the natural gas distribution utilities. The natural gas distribution utilities construct, manage, and maintain intrastate natural gas pipelines and distribution facilities. Details of the natural gas distribution utilities at December 31, 2017 are as follows:

| **Utility** | **State** | **Number of customers** | **Approximate miles of pipe** |
|---|---|---|---|
| | | *(in thousands)* | |
| Nicor Gas | Illinois | 2,228 | 34,300 |
| Atlanta Gas Light Company | Georgia | 1,622 | 33,500 |
| Virginia Natural Gas | Virginia | 299 | 5,600 |
| Elizabethtown Gas (*) | New Jersey | 292 | 3,200 |
| Florida City Gas | Florida | 109 | 3,700 |
| Chattanooga Gas Company | Tennessee | 66 | 1,600 |
| Elkton Gas (*) | Maryland | 7 | 100 |
| **Total** | | 4,623 | 82,000 |

(*) For information relating to the pending asset sales of Elizabethtown Gas and Elkton Gas, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Merger, Acquisition, and Disposition Activities" of Southern Company Gas in Item 7 herein and Note 11 to the financial statements of Southern Company Gas under "Proposed Sale of Elizabethtown Gas and Elkton Gas" in Item 8 herein.

For information relating to the sources of revenue for Southern Company Gas, see MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATIONS and – FUTURE EARNINGS POTENTIAL of Southern Company Gas in Item 7 herein.

**Competition**

***Electric***

The electric utility industry in the U.S. is continuing to evolve as a result of regulatory and competitive factors. Among the early primary agents of change was the Energy Policy Act of 1992, which allowed IPPs to access a utility's transmission network in order to sell electricity to other utilities.

The competition for retail energy sales among competing suppliers of energy is influenced by various factors, including price, availability, technological advancements, service, and reliability. These factors are, in turn, affected by, among other influences, regulatory, political, and environmental considerations, taxation, and supply.

The retail service rights of all electric suppliers in the State of Georgia are regulated by the Territorial Electric Service Act of 1973. Pursuant to the provisions of this Act, all areas within existing municipal limits were assigned to the primary electric supplier therein. Areas outside of such municipal limits were either to be assigned or to be declared open for customer choice of supplier by action of the Georgia PSC pursuant to standards set forth in this Act. Consistent with such standards, the Georgia PSC has assigned substantially all of the land area in the state to a supplier. Notwithstanding such assignments, this Act provides that any new customer locating outside of 1973 municipal limits and having a connected load of at least 900 KWs may exercise a one-time choice for the life of the premises to receive electric service from the supplier of its choice.

Pursuant to the 1956 Utility Act, the Mississippi PSC issued "Grandfather Certificates" of public convenience and necessity to Mississippi Power and to six distribution rural cooperatives operating in southeastern Mississippi, then served in whole or in part by Mississippi Power, authorizing them to distribute electricity in certain specified geographically described areas of the state. The six cooperatives serve approximately 325,000 retail customers in a certificated area of approximately 10,300 square miles. In areas included in a "Grandfather Certificate," the utility holding such certificate may extend or maintain its electric system subject to certain regulatory approvals; extensions of facilities by such utility, or extensions of facilities into that area by other utilities, may not be made except upon a showing of, and a grant of a certificate of, public convenience and necessity. Areas included in such a certificate that are subsequently annexed to municipalities may continue to be served by the holder of the certificate, irrespective of whether it has a franchise in the annexing municipality. On the other hand, the holder of the municipal franchise may not extend service into such newly annexed area without authorization by the Mississippi PSC.

Generally, the traditional electric operating companies have experienced, and expect to continue to experience, competition in their respective retail service territories in varying degrees from the development and deployment of alternative energy sources such as self-generation (as described below) and distributed generation technologies, as well as other factors.

Southern Power competes with investor-owned utilities, IPPs, and others for wholesale energy sales across various U.S. utility markets. The needs of these markets are driven by the demands of end users and the generation available. Southern Power's success in wholesale energy sales is influenced by various factors including reliability and availability of Southern Power's plants, availability of transmission to serve the demand, price, and Southern Power's ability to contain costs.

As of December 31, 2017 , Alabama Power had cogeneration contracts in effect with eight industrial customers. Under the terms of these contracts, Alabama Power purchases excess energy generated by such companies. During 2017 , Alabama Power purchased approximately 98 million KWHs from such companies at a cost of $3 million .

As of December 31, 2017 , Georgia Power had contracts in effect with 27 small power producers whereby Georgia Power purchases their excess generation. During 2017 , Georgia Power purchased 1.6 billion KWHs from such companies at a cost of $114 million . Georgia Power also has PPAs for electricity with four cogeneration facilities. Payments are subject to reductions for failure to meet minimum capacity output. During 2017 , Georgia Power purchased 26 million KWHs at a cost of $0.7 million from these facilities.

Also during 2017 , Georgia Power purchased energy from three customer-owned generating facilities. These customers provide only energy to Georgia Power, make no capacity commitment, and are not dispatched by Georgia Power. During 2017 , Georgia Power purchased a total of 317 million KWHs from the three customers at a cost of approximately $25 million .

As of December 31, 2017 , Gulf Power had agreements in effect with various industrial, commercial, and qualifying facilities pursuant to which Gulf Power purchases "as available" energy from customer-owned generation. During 2017 , Gulf Power purchased 277 million KWHs from such companies for approximately $7 million .

As of December 31, 2017 , Mississippi Power had a cogeneration agreement in effect with one of its industrial customers. Under the terms of this contract, Mississippi Power purchases any excess generation. During 2017 , Mississippi Power did not purchase any excess generation from this customer.

***Natural Gas***

Southern Company Gas' natural gas distribution utilities do not compete with other distributors of natural gas in their exclusive franchise territories but face competition from other energy products. Their principal competitors are electric utilities and fuel oil and propane providers serving the residential, commercial, and industrial markets in their service areas for customers who are considering switching to or from a natural gas appliance.

Competition for heating as well as general household and small commercial energy needs generally occurs at the initial installation phase when the customer or builder makes decisions as to which types of equipment to install. Customers generally use the chosen energy source for the life of the equipment.

Customer demand for natural gas could be affected by numerous factors, including:

- changes in the availability or price of natural gas and other forms of energy;
- general economic conditions;
- energy conservation, including state-supported energy efficiency programs;
- legislation and regulations;
- the cost and capability to convert from natural gas to alternative energy products; and
- technological changes resulting in displacement or replacement of natural gas appliances.

The natural gas-related programs generally emphasize natural gas as the fuel of choice for customers and seek to expand the use of natural gas through a variety of promotional activities. In addition, Southern Company Gas partners with third-party entities to market the benefits of natural gas appliances.

The availability and affordability of natural gas have provided cost advantages and further opportunity for growth of the businesses.

**Seasonality**

The demand for electric power and natural gas supply is affected by seasonal differences in the weather. In most of the areas the traditional electric operating companies serve, electric power sales peak during the summer with a smaller peak during the winter, while in most of the areas Southern Company Gas serves, natural gas demand peaks during the winter. As a result, the overall operating results of Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas in the future may fluctuate substantially on a seasonal basis. In addition, Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas have historically sold less power and natural gas when weather conditions are milder.

**Regulation**

***State Commissions***

The traditional electric operating companies and the natural gas distribution utilities are subject to the jurisdiction of their respective state PSCs or applicable state regulatory agencies. These regulatory bodies have broad powers of supervision and regulation over public utilities operating in the respective states, including their rates, service regulations, sales of securities (except for the Mississippi PSC), and, in the cases of the Georgia PSC and the Mississippi PSC, in part, retail service territories. See "Territory Served by the Southern Company System" and "Rate Matters" herein for additional information.

***Federal Power Act***

The traditional electric operating companies, Southern Power Company and certain of its generation subsidiaries, and SEGCO are all public utilities engaged in wholesale sales of energy in interstate commerce and, therefore, are subject to the rate, financial, and accounting jurisdiction of the FERC under the Federal Power Act. The FERC must approve certain financings and allows an "at cost standard" for services rendered by system service companies such as SCS and Southern Nuclear. The FERC is also authorized to establish regional reliability organizations which enforce reliability standards, address impediments to the construction of transmission, and prohibit manipulative energy trading practices.

Alabama Power and Georgia Power are also subject to the provisions of the Federal Power Act or the earlier Federal Water Power Act applicable to licensees with respect to their hydroelectric developments. As of December 31, 2017 , among the hydroelectric projects subject to licensing by the FERC are 14 existing Alabama Power generating stations having an aggregate installed capacity of 1,670,000 KWs and 17 existing Georgia Power generating stations and one generating station partially owned by Georgia Power, with a combined aggregate installed capacity of 1,087,296 KWs.

In 2013, the FERC issued a new 30-year license to Alabama Power for Alabama Power's seven hydroelectric developments on the Coosa River (Weiss, Henry, Logan Martin, Lay, Mitchell, Jordan, and Bouldin). Alabama Power filed a petition requesting rehearing of the FERC order granting the relicense seeking revisions to several conditions of the license. Alabama Rivers Alliance, American Rivers, the Georgia Environmental Protection Division, and the Atlanta Regional Commission also filed petitions for rehearing of the FERC order. In April 2016, the FERC issued an order granting in part and denying in part Alabama Power's rehearing request. The order also denied all of the other rehearing requests. In May 2016, Alabama Rivers Alliance and American Rivers filed a second rehearing request and, in June 2016, also filed a petition with the U.S. Court of Appeals for the District of Columbia Circuit for review of the license and the rehearing denial order. The FERC issued an order in September 2016 denying the second rehearing request, and American Rivers and Alabama Rivers Alliance subsequently filed an appeal of that order at the U.S. Court of Appeals for the District of Columbia Circuit. The U.S. Court of Appeals for the District of Columbia Circuit consolidated the two appeals into one proceeding.

In 2017, Alabama Power continued the process of developing an application to relicense the Harris Dam project on the Tallapoosa River, which is expected to be filed with the FERC by November 30, 2021. The current Harris Dam project license will expire on November 30, 2023.

In 2017, Georgia Power continued the process of developing an application to relicense the Wallace Dam project on the Oconee River. The current Wallace Dam project license will expire on June 1, 2020. Georgia Power's hydro electric licenses expiring in 2023 include the Lloyd Shoals project, the Riverview project, and the Langdale project. The FERC relicensing proceedings for these three projects are expected to begin in 2018.

Georgia Power and OPC also have a license, expiring in 2027, for the Rocky Mountain Plant, a pure pumped storage facility of 847,800 KW capacity. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

Licenses for all projects, excluding those discussed above, expire in the years 2023-2066 in the case of Alabama Power's projects and in the years 2035-2044 in the case of Georgia Power's projects.

Upon or after the expiration of each license, the U.S. Government, by act of Congress, may take over the project or the FERC may relicense the project either to the original licensee or to a new licensee. In the event of takeover or relicensing to another, the original licensee is to be compensated in accordance with the provisions of the Federal Power Act, such compensation to reflect the net investment of the licensee in the project, not in excess of the fair value of the property, plus reasonable damages to other property of the licensee resulting from the severance therefrom of the property. The FERC may grant relicenses subject to certain requirements that could result in additional costs.

The ultimate outcome of these matters cannot be determined at this time.

***Nuclear Regulation***

Alabama Power, Georgia Power, and Southern Nuclear are subject to regulation by the NRC. The NRC is responsible for licensing and regulating nuclear facilities and materials and for conducting research in support of the licensing and regulatory process, as mandated by the Atomic Energy Act of 1954, as amended; the Energy Reorganization Act of 1974, as amended; and the Nuclear Nonproliferation Act of 1978, as amended; and in accordance with the National Environmental Policy Act of 1969, as amended, and other applicable statutes. These responsibilities also include protecting public health and safety, protecting the environment, protecting and safeguarding nuclear materials and nuclear power plants in the interest of national security, and assuring conformity with antitrust laws.

The NRC licenses for Georgia Power's Plant Hatch Units 1 and 2 expire in 2034 and 2038, respectively. The NRC licenses for Alabama Power's Plant Farley Units 1 and 2 expire in 2037 and 2041, respectively. The NRC licenses for Plant Vogtle Units 1 and 2 expire in 2047 and 2049, respectively.

In 2012, the NRC issued combined construction and operating licenses (COLs) for Plant Vogtle Units 3 and 4. Receipt of the COLs allowed full construction to begin. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Nuclear Construction" of Georgia Power in Item 7 herein and Note 3 to the financial statements of Southern Company under "Nuclear Construction" and Georgia Power under "Retail Regulatory Matters – Nuclear Construction" in Item 8 herein for additional information.

See Notes 1 and 9 to the financial statements of Southern Company, Alabama Power, and Georgia Power in Item 8 herein for information on nuclear decommissioning costs and nuclear insurance.

***Environmental Laws and Regulations***

The Southern Company system's operations are regulated by state and federal environmental agencies through a variety of laws and regulations governing air, water, land, and protection of other natural resources. Compliance with these existing environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions or through market-based contracts. There is no assurance, however, that all such costs will be recovered. For Southern Company Gas, substantially all of these costs are related to former manufactured gas plants sites, which are primarily recovered through existing ratemaking provisions. See Note 3 to the financial statements of Southern Company Gas under "Environmental Matters" in Item 8 herein for additional information.

Compliance with federal environmental laws and resulting regulations has been, and will continue to be, a significant focus for Southern Company, each traditional electric operating company, Southern Power, SEGCO, and Southern Company Gas. New or revised environmental laws and regulations could affect many areas of the traditional electric operating companies', Southern Power's, and the natural gas distribution utilities' operations. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company and each of the traditional electric operating companies in Item 7 herein for additional information about environmental issues, including, but not limited to, proposed and final regulations related to air quality, water quality, CCRs, and global climate issues. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Power in Item 7 herein for additional information about environmental issues and global climate issues. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company Gas in Item 7 herein for additional information about environmental remediation liabilities.

The Southern Company system's ultimate environmental compliance strategy, including potential electric generating unit retirement and replacement decisions, and future environmental capital expenditures will depend on various factors, such as state-level adoption and implementation of requirements, the availability and cost of any deployed control technology, and the outcome of pending and/or future legal challenges. Compliance costs may result from the installation of additional environmental controls, closure and monitoring of CCR facilities, unit retirements, and adding or changing fuel sources for certain existing units, as well as related upgrades to the transmission system. Environmental compliance spending over the next several years may differ materially from the amounts estimated. Such expenditures could affect results of operations, cash flows, and financial condition if such costs are not recovered on a timely basis through regulated rates for the traditional electric operating companies and the natural gas distribution utilities or through long-term wholesale agreements for the traditional electric operating companies and Southern Power. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for energy, which could negatively affect results of operations, cash flows, and financial condition. Additionally, many commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity and natural gas. See "Construction Program" herein and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company, each of the traditional electric operating companies, Southern Power, and Southern Company Gas in Item 7 herein for additional information. The ultimate outcome of these matters cannot be determined at this time.

**Rate Matters**

***Rate Structure and Cost Recovery Plans***

*Electric*

The rates and service regulations of the traditional electric operating companies are uniform for each class of service throughout their respective retail service territories. Rates for residential electric service are generally of the block type based upon KWHs used and include minimum charges. Residential and other rates contain separate customer charges. Rates for commercial service are presently of the block type and, for large customers, the billing demand is generally used to determine capacity and minimum bill charges. These large customers' rates are generally based upon usage by the customer and include rates with special features to encourage off-peak usage. Additionally, Alabama Power, Gulf Power, and Mississippi Power are generally allowed by their respective state PSCs to negotiate the terms and cost of service to large customers. Such terms and cost of service, however, are subject to final state PSC approval.

The traditional electric operating companies recover certain costs through a variety of forward-looking, cost-based rate mechanisms. Fuel and net purchased energy costs are recovered through specific fuel cost recovery provisions. These fuel cost recovery provisions are adjusted to reflect increases or decreases in such costs as needed or on schedules as required by the respective PSCs. Approved compliance, storm damage, and certain other costs are recovered at Alabama Power, Gulf Power, and Mississippi Power through specific cost recovery mechanisms approved by their respective PSCs. Certain similar costs at Georgia Power are recovered through various base rate tariffs as approved by the Georgia PSC. Costs not recovered through specific cost recovery mechanisms are recovered at Alabama Power and Mississippi Power through annual, formulaic cost recovery proceedings and at Georgia Power and Gulf Power through periodic base rate proceedings.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Regulatory Matters" of Southern Company and each of the traditional electric operating companies in Item 7 herein and Note 3 to the financial statements of Southern Company and each of the traditional electric operating companies under "Retail Regulatory Matters" in Item 8 herein for a discussion of rate matters and certain cost recovery mechanisms. Also, see Note 1 to the financial statements of Southern Company and each of the traditional electric operating companies in Item 8 herein for a discussion of recovery of fuel costs, storm damage costs, and compliance costs through rate mechanisms.

See "Integrated Resource Planning" herein for a discussion of Georgia PSC certification of new demand-side or supply-side resources for Georgia Power. In addition, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Nuclear Construction" of Georgia Power in Item 7 herein and Note 3 to the financial statements of Southern Company under "Nuclear Construction" and Georgia Power under "Retail Regulatory Matters – Nuclear Construction" in Item 8 herein for a discussion of the Georgia Nuclear Energy Financing Act and the Georgia PSC certification of Plant Vogtle Units 3 and 4, which have allowed Georgia Power to recover financing costs for construction of Plant Vogtle Units 3 and 4 during the construction period beginning in 2011.

See Note 3 to the financial statements of Southern Company and Mississippi Power under "Kemper County Energy Facility" in Item 8 herein and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Kemper County Energy Facility – Rate Recovery" of Mississippi Power in Item 7 herein for information on cost recovery plans with respect to the Kemper County energy facility.

The traditional electric operating companies and Southern Power Company and certain of its generation subsidiaries are authorized by the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters" of each of the registrants in Item 7 herein for information on the traditional electric operating companies' and Southern Power Company's market-based rate authority and pending FERC proceedings relating to this authority.

Mississippi Power serves long-term contracts with rural electric cooperative associations and a municipality located in southeastern Mississippi under cost-based electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represented 19.3% of Mississippi Power's operating revenues in 2017 and are largely subject to rolling 10-

year cancellation notices. Historically, these wholesale customers have acted as a group and any changes in contractual relationships for one customer are likely to be followed by the other wholesale customers.

*Natural Gas*

Southern Company Gas' seven natural gas distribution utilities are subject to regulation and oversight by their respective state regulatory agencies with respect to rates charged to their customers, maintenance of accounting records, and various service and safety matters. Rates charged to these customers vary according to customer class (residential, commercial, or industrial) and rate jurisdiction. These agencies approve rates designed to provide each natural gas distribution utility the opportunity to generate revenues to recover all prudently-incurred costs, including a return on rate base sufficient to pay interest on debt, and provide a reasonable return. Rate base generally consists of the original cost of the utility plant in service, working capital, and certain other assets, less accumulated depreciation on the utility plant in service and net deferred income tax liabilities, and may include certain other additions or deductions.

With the exception of Atlanta Gas Light Company, which operates in a deregulated environment in which gas marketers rather than a traditional utility sell natural gas to end-use customers and earns revenue by charging rates to its customers based primarily on monthly fixed charges that are set by the Georgia PSC, the earnings of the natural gas distribution utilities can be affected by customer consumption patterns that are largely a function of weather conditions and price levels for natural gas.

The natural gas distribution utilities, excluding Atlanta Gas Light Company, are authorized to use natural gas cost recovery mechanisms that allow them to adjust their rates to reflect changes in the wholesale cost of natural gas and to ensure they recover all of the costs prudently incurred in purchasing natural gas for their customers. In addition to natural gas cost recovery mechanisms, the natural gas distribution utilities have other cost recovery mechanisms, such as regulatory riders, which vary by utility but allow recovery of certain costs, such as those related to infrastructure replacement programs as well as environmental remediation and energy efficiency plans.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Regulatory Matters – Utility Regulation and Rate Design" of Southern Company Gas in Item 7 herein and Note 3 to the financial statements of Southern Company Gas under "Regulatory Matters" in Item 8 herein for a discussion of rate matters and certain cost recovery mechanisms.

***Integrated Resource Planning***

Each of the traditional electric operating companies continually evaluates its electric generating resources in order to ensure that it maintains a cost-effective and reliable mix of resources to meet the existing and future demand requirements of its customers. See "Environmental Laws and Regulations" above for a discussion of existing and potential environmental regulations that may impact the future generating resource needs of the traditional electric operating companies.

Certain of the traditional electric operating companies are required to file IRPs with their respective state PSC as discussed below.

*Georgia Power*

Triennially, Georgia Power must file an IRP with the Georgia PSC that specifies how it intends to meet the future electric service needs of its customers through a combination of demand-side and supply-side resources. The Georgia PSC, under state law, must certify any new demand-side or supply-side resources for Georgia Power to receive cost recovery. Once certified, the lesser of actual or certified construction costs and purchased power costs is recoverable through rates. Certified costs may be excluded from recovery only on the basis of fraud, concealment, failure to disclose a material fact, imprudence, or criminal misconduct.

See Note 3 to the financial statements of Southern Company under "Regulatory Matters – Georgia Power – Rate Plans" and " – Integrated Resource Plan" and "Nuclear Construction" and Note 3 to the financial statements of Georgia Power under "Retail Regulatory Matters – Rate Plans," "– Integrated Resource Plan," and "– Nuclear Construction" in Item 8 herein for additional information.

*Gulf Power*

Annually by April 1, Gulf Power must file a 10-year site plan with the Florida PSC containing Gulf Power's estimate of its power-generating needs in the period and the general location of its proposed power plant sites. The 10-year site plans submitted by the state's electric utilities are reviewed by the Florida PSC and subsequently classified as either "suitable" or "unsuitable." The Florida PSC then reports its findings along with any suggested revisions to the Florida Department of Environmental Protection for its consideration at any subsequent electrical power plant site certification proceedings. Under

Florida law, any 10-year site plans submitted by an electric utility are considered tentative information for planning purposes only and may be amended at any time at the discretion of the utility with written notification to the Florida PSC.

Gulf Power's most recent 10-year site plan was classified by the Florida PSC as "suitable" in November 2017. The plan identifies environmental regulations and potential legislation or regulation that would impose mandatory restrictions on greenhouse gas emissions. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations – Air Quality," "– Environmental Laws and Regulations – Coal Combustion Residuals," and "– Global Climate Issues" of Gulf Power in Item 7 herein.

As a result of the cost to comply with environmental regulations imposed by the EPA, Gulf Power retired its coal-fired generation at Plant Smith Units 1 and 2 (357 MWs) in March 2016. In August 2016, the Florida PSC approved Gulf Power's request to reclassify the remaining net book value of Plant Smith Units 1 and 2 and the remaining materials and supplies associated with these units as of the retirement date, totaling approximately $63 million, to a regulatory asset. Gulf Power began amortizing the investment balances over 15 years effective January 1, 2018 as determined in a rate case settlement agreement approved by the Florida PSC on April 4, 2017.

*Mississippi Power*

Mississippi Power's 2010 IRP indicated that, among other things, Mississippi Power planned to construct the Kemper County energy facility as an IGCC to meet its identified needs, to add environmental controls at Plant Daniel Units 1 and 2, to defer environmental controls at Plant Watson Units 4 and 5, and to continue operation of the combined cycle Plant Daniel Units 3 and 4. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations – Air Quality" and "– Global Climate Issues" of Mississippi Power in Item 7 herein.

On February 6, 2018, the Mississippi PSC approved a settlement agreement related to cost recovery for the Kemper County energy facility, pursuant to which Mississippi Power agreed to file a Reserve Margin Plan (RMP) by August 2018. The RMP will include many of the same aspects of a traditional IRP, but the RMP will also contain alternatives proposed by Mississippi Power to address its current capacity which is in excess of Mississippi Power's long-term targeted reserve margin. The ultimate outcome of this matter cannot be determined at this time.

For additional information regarding the Kemper County energy facility, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Kemper County Energy Facility" of Mississippi Power in Item 7 herein and Note 3 to the financial statements of Southern Company and Mississippi Power under "Kemper County Energy Facility" in Item 8 herein.

**Employee Relations**

The Southern Company system had a total of 31,344 employees on its payroll at December 31, 2017.

| | Employees at December 31, 2017 |
|---|---|
| Alabama Power | 6,613 |
| Georgia Power | 6,986 |
| Gulf Power | 1,288 |
| Mississippi Power | 1,242 |
| PowerSecure | 1,448 |
| SCS | 3,740 |
| Southern Company Gas | 5,318 |
| Southern Nuclear | 3,936 |
| Southern Power | 541 |
| Other | 232 |
| Total | 31,344 |

The traditional electric operating companies and the natural gas distribution utilities have separate agreements with local unions of the IBEW and the Utilities Workers Union of America generally covering wages, working conditions, and procedures for handling grievances and arbitration. These agreements apply with certain exceptions to operating, maintenance, and construction employees.

Alabama Power has agreements with the IBEW in effect through August 15, 2019. Upon notice given at least 60 days prior to that date, negotiations may be initiated with respect to agreement terms to be effective after such date.

Georgia Power has an agreement with the IBEW covering wages and working conditions, which is in effect through June 30, 2021.

Gulf Power has an agreement with the IBEW covering wages and working conditions, which is in effect through April 15, 2019. Upon notice given at least 60 days prior to that date, negotiations may be initiated with respect to agreement terms to be effective after such date.

Mississippi Power has an agreement with the IBEW covering wages and working conditions, which is in effect through May 1, 2019. In 2015, Mississippi Power signed a separate agreement with the IBEW related solely to the Kemper County energy facility; that current agreement is in effect through March 15, 2021. In August 2017, Mississippi Power signed an agreement with the IBEW that added several job classifications and provided guidelines related to the reorganization at the Kemper County energy facility.

Southern Nuclear has a five-year agreement with the IBEW covering certain employees at Plants Hatch and Plant Vogtle Units 1 and 2, which is in effect through June 30, 2021. A five-year agreement between Southern Nuclear and the IBEW representing certain employees at Plant Farley is in effect through August 15, 2019. Upon notice given at least 60 days prior to that date, negotiations may be initiated with respect to agreement terms to be effective after such date.

The agreements also make the terms of the pension plans for the companies discussed above subject to collective bargaining with the unions at either a five-year or a 10-year cycle, depending upon union and company actions.

The natural gas distribution utilities have separate agreements with local unions of the IBEW and Utilities Workers Union of America covering wages, working conditions, and procedures for handling grievances and arbitration. Nicor Gas' agreement with the IBEW is effective through February 29, 2020. Virginia Natural Gas' agreement with the IBEW is effective through May 16, 2020. Elizabethtown Gas' agreement with the Utility Workers Union of America is effective through November 21, 2019. The agreements also make the terms of the Southern Company Gas pension plan subject to collective bargaining with the unions when significant changes to the benefit accruals are considered by Southern Company Gas.

Effective in December 2017, 538 employees transferred from SCS to Southern Power. Southern Power became obligated for related employee costs including pension, other postretirement benefits, and stock-based compensation and has recognized the respective balance sheet assets and liabilities, including accumulated other comprehensive income impacts, in its balance sheet at December 31, 2017. Prior to the transfer of employees, Southern Power's agreements with SCS provided for employee services rendered at amounts in compliance with FERC regulations.

## Item 1A. RISK FACTORS

**In addition to the other information in this Form 10-K, including MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL in Item 7 of each registrant, and other documents filed by Southern Company and/or its subsidiaries with the SEC from time to time, the following factors should be carefully considered in evaluating Southern Company and its subsidiaries. Such factors could affect actual results and cause results to differ materially from those expressed in any forward-looking statements made by, or on behalf of, Southern Company and/or its subsidiaries.**

### UTILITY REGULATORY, LEGISLATIVE, AND LITIGATION RISKS

**Southern Company and its subsidiaries are subject to substantial state and federal governmental regulation. Compliance with current and future regulatory requirements and procurement of necessary approvals, permits, and certificates may result in substantial costs to Southern Company and its subsidiaries.**

Southern Company and its subsidiaries, including the traditional electric operating companies, Southern Power, and Southern Company Gas, are subject to substantial regulation from federal, state, and local regulatory agencies. Southern Company and its subsidiaries are required to comply with numerous laws and regulations and to obtain numerous permits, approvals, and certificates from the governmental agencies that regulate various aspects of their businesses. Jointly-owned facilities may be subject to regulation by governmental agencies of more than one state and those state's governmental agencies may have different policies with respect to such jointly-owned facilities. The traditional electric operating companies and the natural gas distribution utilities seek to recover their costs (including a reasonable return on invested capital) through their retail rates, which must be approved by the applicable state PSC or other applicable state regulatory agency. A state PSC or other applicable state regulatory agency, in a future rate proceeding, may alter the timing or amount of certain costs for which recovery is allowed or modify the current authorized rate of return. Rate refunds may also be required. Additionally, the rates charged to wholesale customers by the traditional electric operating companies and by Southern Power and the rates charged to natural gas transportation customers by Southern Company Gas' pipeline investments must be approved by the FERC. These wholesale rates could be affected by changes to Southern Power's and the traditional electric operating companies' ability to conduct business pursuant to FERC market-based rate authority. The FERC rules related to retaining the authority to sell electricity at market-based rates in the wholesale markets are important for the traditional electric operating companies and Southern Power if they are to remain competitive in the wholesale markets in which they operate.

The impact of any future revision or changes in interpretations of existing regulations or the adoption of new laws and regulations applicable to Southern Company or any of its subsidiaries is uncertain. Changes in regulation or the imposition of additional regulations could influence the operating environment of Southern Company and its subsidiaries and may result in substantial costs or otherwise negatively affect their results of operations.

**The Southern Company system's costs of compliance with environmental laws are significant. The costs of compliance with current and future environmental laws and the incurrence of environmental liabilities could negatively impact the net income, cash flows, and financial condition of the registrants.**

The Southern Company system's operations are subject to extensive regulation by state and federal environmental agencies through a variety of laws and regulations governing air, water, land, and the protection of other natural resources. Compliance with these existing environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions or through market-based contracts. There is no assurance, however, that all such costs will be recovered. The registrants expect that these expenditures will continue to be significant in the future.

The EPA has adopted and is implementing regulations governing air and water quality, including the emission of nitrogen oxide, sulfur dioxide, fine particulate matter, ozone, mercury, and other air pollutants under the Clean Air Act and regulations governing cooling water intake structures and effluent guidelines for steam electric generating plants under the Clean Water Act. The EPA also is reconsidering regulations governing the disposal of CCR, including coal ash and gypsum, in landfills and surface impoundments at power generation plants.

Additionally, environmental laws and regulations covering the handling and disposal of waste and release of hazardous substances could require the Southern Company system to incur substantial costs to clean up affected sites, including certain current and former operating sites, and locations affected by historical operations or subject to contractual obligations.

Existing environmental laws and regulations may be revised or new laws and regulations related to air, water, land, and the protection of other natural resources may be adopted or become applicable to the traditional electric operating companies, Southern Power, and/or Southern Company Gas.

Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as standards for air, water, land, and protection of other natural resources, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by $CO_2$ and other emissions, CCR, releases of regulated substances, and alleged exposure to regulated substances, and/or requests for injunctive relief in connection with such matters.

The Southern Company system's ultimate environmental compliance strategy, including potential electric generating unit retirement and replacement decisions, and future environmental capital expenditures will depend on various factors, such as state adoption and implementation of requirements, the availability and cost of any deployed control technology, and the outcome of pending and/or future legal challenges. Compliance costs may result from the installation of additional environmental controls, closure and monitoring of CCR facilities, unit retirements, and adding or changing fuel sources for certain existing units, as well as related upgrades to the transmission system. Environmental compliance spending over the next several years may differ materially from the amounts estimated. Such expenditures could affect results of operations, cash flows, and financial condition if such costs are not recovered on a timely basis through regulated rates for the traditional electric operating companies and the natural gas distribution utilities or through long-term wholesale agreements for the traditional electric operating companies and Southern Power. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for energy, which could negatively affect results of operations, cash flows, and financial condition. Additionally, many commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity or natural gas.

Compliance with any new or revised environmental laws or regulations could affect many areas of the traditional electric operating companies', Southern Power's, and the natural gas distribution utilities' operations. The ultimate impact will depend on various factors, such as state adoption and implementation of requirements, the availability and cost of any deployed control technology, and the outcome of pending and/or future legal challenges. Additionally, many commercial and industrial customers may also be affected by existing and future environmental requirements, which may affect their demand for electricity and natural gas.

**The Southern Company system may be exposed to regulatory and financial risks related to the impact of greenhouse gas (GHG) legislation and regulation.**

In 2015, the EPA published final rules limiting $CO_2$ emissions from new, modified, and reconstructed fossil fuel-fired electric generating units and guidelines for states to develop plans to meet EPA-mandated $CO_2$ emission performance standards for existing units (known as the Clean Power Plan or CPP). In February 2016, the U.S. Supreme Court granted a stay of the CPP, which will remain in effect through the resolution of the litigation in the U.S. Court of Appeals for the District of Columbia challenging the legality of the CPP and any review by the U.S. Supreme Court. On March 28, 2017, the U.S. President signed an executive order directing agencies to review actions that potentially burden the development or use of domestically produced energy resources, including review of the CPP and other $CO_2$ emissions rules. On October 10, 2017, the EPA published a proposed rule to repeal the CPP and, on December 28, 2017, published an advanced notice of proposed rulemaking regarding a CPP replacement rule.

In 2015, parties to the United Nations Framework Convention on Climate Change, including the United States, adopted the Paris Agreement, which established a non-binding universal framework for addressing GHG emissions based on nationally determined contributions. On June 1, 2017, the U.S. President announced that the United States would withdraw from the Paris Agreement and begin renegotiating its terms. The ultimate impact of this agreement or any renegotiated agreement depends on its implementation by participating countries.

Costs associated with these actions could be significant to the utility industry and the Southern Company system. However, the ultimate impact of these environmental laws and regulations will depend on various factors, such as state adoption and implementation of requirements, the availability and cost of any deployed control technology, and the outcome of pending and/or future legal challenges.

Because natural gas is a fossil fuel with lower carbon content relative to other fossil fuels, future GHG constraints may create additional demand for natural gas, both for production of electricity and direct use in homes and businesses. The impact is already being seen in the power production sector due to both environmental regulations and low natural gas costs. Future GHG constraints focused on minimizing emissions from natural gas, albeit lower than other fossil fuels, could likewise result in increased costs to the Southern Company system and affect the demand for natural gas as well as the prices charged to customers and the competitive position of natural gas.

**The net income of Southern Company, the traditional electric operating companies, and Southern Power could be negatively impacted by changes in regulations related to transmission planning processes and competition in the wholesale electric markets.**

The traditional electric operating companies currently own and operate transmission facilities as part of a vertically integrated utility. A small percentage of transmission revenues are collected through the wholesale electric tariff but the majority of transmission revenues are collected through retail rates. FERC rules pertaining to regional transmission planning and cost allocation present challenges to transmission planning and the wholesale market structure in the Southeast. The key impacts of these rules include:

- possible disruption of the integrated resource planning processes within the states in the Southern Company system's service territory;
- delays and additional processes for developing transmission plans; and
- possible impacts on state jurisdiction of approving, certifying, and pricing new transmission facilities.

The FERC rules related to transmission are intended to spur the development of new transmission infrastructure to promote and encourage the integration of renewable sources of supply as well as facilitate competition in the wholesale market by providing more choices to wholesale power customers. Technology changes in the power and fuel industries continue to create significant impacts to wholesale transaction cost structures. The impact of these and other such developments and the effect of changes in levels of wholesale supply and demand are uncertain. The financial condition, net income, and cash flows of Southern Company, the traditional electric operating companies, and Southern Power could be adversely affected by these and other changes.

**The traditional electric operating companies and Southern Power could be subject to higher costs as a result of implementing and maintaining compliance with the North American Electric Reliability Corporation mandatory reliability standards along with possible associated penalties for non-compliance.**

Owners and operators of bulk power systems, including the traditional electric operating companies, are subject to mandatory reliability standards enacted by the North American Electric Reliability Corporation and enforced by the FERC. Compliance with or changes in the mandatory reliability standards may subject the traditional electric operating companies and Southern Power to higher operating costs and/or increased capital expenditures. If any traditional electric operating company or Southern Power is found to be in noncompliance with these standards, such traditional electric operating company or Southern Power could be subject to sanctions, including substantial monetary penalties.

**Southern Company and its subsidiaries are continuing to review the Tax Reform Legislation, which has and could have a further material impact on the results of operations, financial condition, and cash flows of the registrants.**

On December 22, 2017, the Tax Reform Legislation was signed into law and became effective on January 1, 2018. The Tax Reform Legislation significantly changes the U.S. Internal Revenue Code by, among other things, reducing the federal corporate income tax rate to 21% and repealing the corporate alternative minimum tax. As a result of the tax rate reduction, Southern Company recorded net, non-cash federal income tax benefits of $264 million in the fourth quarter 2017, comprised primarily of a $743 million tax benefit resulting from reductions in deferred tax liabilities at Southern Power, partially offset by tax expenses of $372 million and $93 million resulting from reductions in deferred tax assets at Mississippi Power and Southern Company Gas, respectively.

The tax rate reduction also resulted in a $6.9 billion increase in regulatory liabilities and a $0.4 billion decrease in regulatory assets across the traditional electric operating companies and the natural gas distribution utilities. The regulatory treatment of certain impacts of the Tax Reform Legislation is subject to the discretion of the FERC and the relevant state regulatory bodies.

For businesses other than regulated utility businesses, the Tax Reform Legislation allows 100% bonus depreciation of qualified property through 2022, which phases down through 2027, and limits interest expense deductions. Regulated utility businesses, including the majority of the operations of the traditional electric operating companies and the natural gas distribution companies, can continue deducting all business interest expense and are not eligible for bonus depreciation on capital assets acquired and placed in service after September 27, 2017. The Tax Reform Legislation retains normalization provisions for public utility property and existing renewable energy incentives. However, the tax rate reduction delays the utilization of renewable tax credit carryforwards as described in Note 5 to the financial statements of Southern Company, Alabama Power, Georgia Power, and Southern Power under "Federal Tax Reform Legislation" in Item 8 herein.

The Tax Reform Legislation also includes provisions that limit the utilization of future net operating losses and limit the deductibility of certain executive compensation and other expenses. Further, while it is unclear how the credit rating agencies, the FERC, and relevant state regulatory bodies may respond to the Tax Reform Legislation, certain financial metrics, such as funds from operations to debt percentage, used by the credit rating agencies to assess the registrants, Southern Company Gas Capital, and Nicor Gas may be negatively impacted.

The Tax Reform Legislation is unclear in certain respects and will require interpretations, guidance, and implementing regulations by the IRS, as well as each respective state's adoption. In addition, the regulatory treatment of certain impacts of the Tax Reform Legislation is subject to the discretion of the FERC and relevant state regulatory bodies. Southern Company and its subsidiaries are continuing to review the Tax Reform Legislation and are assessing whether any potential actions are available to mitigate adverse impacts of the legislation. Southern Company and its subsidiaries may identify additional impacts as they further assess the Tax Reform Legislation and as the IRS issues interpretations and implements regulations. Southern Company will continue to monitor the actions of state legislatures and state taxing authorities to see how the states may adopt and implement the Tax Reform Legislation. While the ultimate impact of the Tax Reform Legislation, future interpretations and implementation of regulations by the IRS and state tax authorities, and any mitigating actions Southern Company and its subsidiaries may take cannot be determined at this time, the Tax Reform Legislation had and could have a further material impact on the results of operations, financial condition and cash flows of the registrants.

## OPERATIONAL RISKS

**The financial performance of Southern Company and its subsidiaries may be adversely affected if the subsidiaries are unable to successfully operate their facilities or perform certain corporate functions.**

The financial performance of Southern Company and its subsidiaries depends on the successful operation of the electric utilities' generating, transmission, and distribution facilities and Southern Company Gas' natural gas distribution and storage facilities and the successful performance of necessary corporate functions. There are many risks that could affect these operations and performance of corporate functions, including:

- operator error or failure of equipment or processes;
- accidents or explosions;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- labor disputes;
- terrorist attacks (physical and/or cyber);
- fuel or material supply interruptions;
- transmission disruption or capacity constraints, including with respect to the Southern Company system's and third parties' transmission, storage, and transportation facilities;
- compliance with mandatory reliability standards, including mandatory cyber security standards;
- implementation of new technologies;
- information technology system failure;
- cyber intrusion;
- an environmental event, such as a spill or release; and
- catastrophic events such as fires, earthquakes, floods, droughts, hurricanes, tornadoes, and storms, pandemic health events such as influenzas, or other similar occurrences.

A decrease or elimination of revenues from the electric generation, transmission, or distribution facilities or natural gas distribution or storage facilities or an increase in the cost of operating the facilities would reduce the net income and cash flows and could adversely impact the financial condition of the affected traditional electric operating company, Southern Power, or Southern Company Gas and of Southern Company.

**Operation of nuclear facilities involves inherent risks, including environmental, safety, health, regulatory, natural disasters, terrorism, and financial risks, that could result in fines or the closure of the nuclear units owned by Alabama Power or Georgia Power and which may present potential exposures in excess of insurance coverage.**

Alabama Power owns, and contracts for the operation of, two nuclear units and Georgia Power holds undivided interests in, and contracts for the operation of, four existing nuclear units. The six existing units are operated by Southern Nuclear and represent approximately 3,680 MWs, or 8% of the Southern Company system's electric generation capacity as of December 31, 2017 . In addition, these units generated approximately 25% of the total KWHs generated by each of Alabama Power and Georgia Power in the year ended December 31, 2017 . In addition, Southern Nuclear, on behalf of Georgia Power and the other Vogtle Owners, is managing the construction of Plant Vogtle Units 3 and 4. Due solely to the increase in nuclear generating capacity, the below risks are expected to increase incrementally once Plant Vogtle Units 3 and 4 are operational. Nuclear facilities are subject to environmental, safety, health, operational, and financial risks such as:

- the potential harmful effects on the environment and human health and safety resulting from a release of radioactive materials in connection with the operation of nuclear facilities and the storage, handling, and disposal of radioactive material, including spent nuclear fuel;
- uncertainties with respect to the ability to dispose of spent nuclear fuel and the need for longer term on-site storage;
- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of licensed lives and the ability to maintain and anticipate adequate capital reserves for decommissioning;

- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with the nuclear operations of Alabama Power and Georgia Power or those of other commercial nuclear facility owners in the U.S.;
- potential liabilities arising out of the operation of these facilities;
- significant capital expenditures relating to maintenance, operation, security, and repair of these facilities, including repairs and upgrades required by the NRC;
- the threat of a possible terrorist attack, including a potential cyber security attack; and
- the potential impact of an accident or natural disaster.

It is possible that damages, decommissioning, or other costs could exceed the amount of decommissioning trusts or external insurance coverage, including statutorily required nuclear incident insurance.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines and/or shut down any unit, depending upon its assessment of the severity of the situation, until compliance is achieved. NRC orders or regulations related to increased security measures and any future safety requirements promulgated by the NRC could require Alabama Power and Georgia Power to make substantial operating and capital expenditures at their nuclear plants. In addition, if a serious nuclear incident were to occur, it could result in substantial costs to Alabama Power or Georgia Power and Southern Company. A major incident at a nuclear facility anywhere in the world could cause the NRC to delay or prohibit construction of new nuclear units or require additional safety measures at new and existing units. Moreover, a major incident at any nuclear facility in the U.S., including facilities owned and operated by third parties, could require Alabama Power and Georgia Power to make material contributory payments.

In addition, potential terrorist threats could result in increased nuclear licensing or compliance costs that are difficult to predict.

**Transporting and storing natural gas involves risks that may result in accidents and other operating risks and costs.**

Southern Company Gas' natural gas distribution and storage activities involve a variety of inherent hazards and operating risks, such as leaks, accidents, explosions, and mechanical problems, which could result in serious injury to employees and non-employees, loss of human life, significant damage to property, environmental pollution, and impairment of its operations. The location of pipelines and storage facilities near populated areas could increase the level of damage resulting from these risks. Additionally, these pipeline and storage facilities are subject to various state and other regulatory requirements. Failure to comply with these regulatory requirements could result in substantial monetary penalties or potential early retirement of storage facilities, which could trigger an associated impairment. The occurrence of any of these events not fully covered by insurance or otherwise could adversely affect Southern Company Gas' and Southern Company's financial condition and results of operations.

**Physical attacks, both threatened and actual, could impact the ability of the traditional electric operating companies, Southern Power, and Southern Company Gas to operate and could adversely affect financial results and liquidity.**

The traditional electric operating companies, Southern Power, and Southern Company Gas face the risk of physical attacks, both threatened and actual, against their respective generation and storage facilities and the transmission and distribution infrastructure used to transport energy, which could negatively impact their ability to generate, transport, and deliver power, or otherwise operate their respective facilities, or, with respect to Southern Company Gas, its ability to distribute or store natural gas, or otherwise operate its facilities, in the most efficient manner or at all. In addition, physical attacks against key suppliers or service providers could have a similar effect on Southern Company and its subsidiaries.

Despite the implementation of robust security measures, all assets are potentially vulnerable to disability, failures, or unauthorized access due to human error, natural disasters, technological failure, or internal or external physical attacks. If assets were to fail, be physically damaged, or be breached and were not recovered in a timely way, the traditional electric operating companies, Southern Power, or Southern Company Gas, as applicable, may be unable to fulfill critical business functions. Moreover, the amount and scope of insurance maintained against losses resulting from any such events or physical security breaches may not be sufficient to cover losses or otherwise adequately compensate for any disruptions to business that could result.

These events could harm the reputation of and negatively affect the financial results of the registrants through lost revenues and costs to repair damage, if such costs cannot be recovered.

**An information security incident, including a cybersecurity breach, or the failure of one or more key information technology systems, networks, or processes could impact the ability of the registrants to operate and could adversely affect financial results and liquidity.**

Information security risks have generally increased in recent years as a result of the proliferation of new technology and increased sophistication and frequency of cyber attacks and data security breaches. The traditional electric operating companies, Southern Power, and Southern Company Gas operate in highly regulated industries that require the continued operation of sophisticated information technology systems and network infrastructure, which are part of interconnected distribution systems. Because of the critical nature of the infrastructure, increased connectivity to the internet, and technology systems' inherent vulnerability to disability or failures due to hacking, viruses, acts of war or terrorism, or other types of data security breaches, Southern Company and its subsidiaries face a heightened risk of cyberattack. Parties that wish to disrupt the U.S. bulk power system or Southern Company system operations could view these computer systems, software, or networks as targets. The registrants and their third-party vendors have been subject, and will likely continue to be subject, to attempts to gain unauthorized access to their information technology systems and confidential data or to attempts to disrupt utility operations. As a result, Southern Company and its subsidiaries face on-going threats to their assets, including assets deemed critical infrastructure, where databases and systems have been, and will likely continue to be, subject to advanced computer viruses or other malicious codes, unauthorized access attempts, phishing, and other cyber attacks. While there has been no material impact on business or operations from these attacks, the registrants cannot guarantee that security efforts will prevent breaches, operational incidents, or other breakdowns of information technology systems and network infrastructure.

In addition, in the ordinary course of business, Southern Company and its subsidiaries collect and retain sensitive information, including personally identifiable information about customers, employees, and stockholders, and other confidential information. In some cases, administration of certain functions may be outsourced to third party service providers that could also be targets of cyber attacks. Generally, Southern Company and its subsidiaries enter certain contractual security guarantees and assurances with these third parties to help ensure the security and safety of this information.

Despite the implementation of robust security measures, all assets are potentially vulnerable to disability, failures, or unauthorized access due to human error, natural disasters, technological failure, or internal or external cyber attacks. If assets were to fail or be breached and were not recovered in a timely way, the affected registrant may be unable to fulfill critical business functions, and sensitive and other data could be compromised. Any cyber breach or theft, damage, or improper disclosure of sensitive electronic data may also subject the affected registrant to penalties and claims from regulators or other third parties. Moreover, the amount and scope of insurance maintained against losses resulting from any such events or security breaches may not be sufficient to cover losses or otherwise adequately compensate for any disruptions to business that could result.

These events could negatively affect the financial results of the registrants through lost revenues, costs to recover and repair damage, and costs associated with governmental actions in response to such attacks, litigation, and reputational damage if such costs cannot be recovered through insurance or otherwise.

**The Southern Company system may not be able to obtain adequate natural gas and other fuel supplies required to operate the traditional electric operating companies' and Southern Power's electric generating plants or serve Southern Company Gas' natural gas customers.**

The traditional electric operating companies and Southern Power purchase fuel, including coal, natural gas, uranium, fuel oil, and biomass, as applicable, from a number of suppliers. Disruption in the delivery of fuel, including disruptions as a result of, among other things, transportation delays, weather, labor relations, force majeure events, or environmental regulations affecting any of these fuel suppliers, could limit the ability of the traditional electric operating companies and Southern Power to operate certain facilities, which could result in higher fuel and operating costs and potentially reduce the net income of the affected traditional electric operating company or Southern Power and Southern Company.

Southern Company Gas' primary business is the distribution and sale of natural gas through its regulated and unregulated subsidiaries. Natural gas supplies can be subject to disruption in the event production or distribution is curtailed, such as in the event of a hurricane or a pipeline failure. Southern Company Gas also relies on natural gas pipelines and other storage and transportation facilities owned and operated by third parties to deliver natural gas to wholesale markets and to Southern Company Gas' distribution systems. The availability of shale gas and potential regulations affecting its accessibility may have a material impact on the supply and cost of natural gas. Disruption in natural gas supplies could limit the ability to fulfill these contractual obligations.

The traditional electric operating companies and Southern Power have become more dependent on natural gas for a portion of their electric generating capacity. In many instances, the cost of purchased power for the traditional electric operating companies and Southern Power is influenced by natural gas prices. Historically, natural gas prices have been more volatile than prices of other fuels. In recent years, domestic natural gas prices have been depressed by robust supplies, including production from shale gas. These market conditions, together with additional regulation of coal-fired generating units, have increased the traditional electric operating companies' reliance on natural gas-fired generating units.

The traditional electric operating companies are also dependent on coal for a portion of their electric generating capacity. The traditional electric operating companies depend on coal supply contracts, and the counterparties to these agreements may not fulfill their obligations to supply coal to the traditional electric operating companies. The suppliers may experience financial or technical problems that inhibit their ability to fulfill their obligations. In addition, the suppliers may not be required to supply coal under certain circumstances, such as in the event of a natural disaster. If the traditional electric operating companies are unable to obtain their coal requirements under these contracts, they may be required to purchase their coal requirements at higher prices, which may not be recoverable through rates.

**The revenues of Southern Company, the traditional electric operating companies, and Southern Power depend in part on sales under PPAs. The failure of a counterparty to one of these PPAs to perform its obligations, the failure of the traditional electric operating companies or Southern Power to satisfy minimum requirements under the PPAs, or the failure to renew the PPAs or successfully remarket the related generating capacity could have a negative impact on the net income and cash flows of the affected traditional electric operating company or Southern Power and of Southern Company.**

Most of Southern Power's generating capacity has been sold to purchasers under PPAs. Southern Power's top three customers, Georgia Power, Duke Energy Corporation, and Morgan Stanley Capital Group accounted for 11.3%, 6.7%, and 4.5%, respectively, of Southern Power's total revenues for the year ended December 31, 2017 . In addition, the traditional electric operating companies enter into PPAs with non-affiliated parties. Revenues are dependent on the continued performance by the purchasers of their obligations under these PPAs. The failure of one of the purchasers to perform its obligations could have a negative impact on the net income and cash flows of the affected traditional electric operating company or Southern Power and of Southern Company. Although the credit evaluations undertaken and contractual protections implemented by Southern Power and the traditional electric operating companies take into account the possibility of default by a purchaser, actual exposure to a default by a purchaser may be greater than predicted or specified in the applicable contract.

Additionally, neither Southern Power nor any traditional electric operating company can predict whether the PPAs will be renewed at the end of their respective terms or on what terms any renewals may be made. The failure of the traditional electric operating companies or Southern Power to satisfy minimum operational or availability requirements under these PPAs could result in payment of damages or termination of the PPAs.

**The asset management arrangements between Southern Company Gas' wholesale gas services and its customers, including the natural gas distribution utilities, may not be renewed or may be renewed at lower levels, which could have a significant impact on Southern Company Gas' financial results.**

Southern Company Gas' wholesale gas services currently manages the storage and transportation assets of the natural gas distribution utilities except Nicor Gas. The profits earned from the management of these affiliate assets are shared with the respective affiliate's customers (and for Atlanta Gas Light Company with the Georgia PSC's Universal Service Fund), except for Chattanooga Gas Company and Elkton Gas where wholesale gas services are provided under annual fixed-fee agreements. These asset management agreements are subject to regulatory approval and such agreements may not be renewed or may be renewed with less favorable terms.

Southern Company Gas' wholesale gas services also has asset management agreements with certain non-affiliated customers and its financial results could be significantly impacted if these agreements are not renewed or are amended or renewed with less favorable terms. Sustained low natural gas prices could reduce the demand for these types of asset management arrangements.

**Increased competition could negatively impact Southern Company's and its subsidiaries' revenues, results of operations, and financial condition.**

The Southern Company system faces increasing competition from other companies that supply energy or generation and storage technologies. Changes in technology may make the Southern Company system's electric generating facilities owned by the traditional electric operating companies and Southern Power less competitive. Southern Company Gas' business is dependent on natural gas prices remaining competitive as compared to other forms of energy. Southern Company Gas also faces competition in its unregulated markets.

A key element of the business models of the traditional electric operating companies and Southern Power is that generating power at central station power plants achieves economies of scale and produces power at a competitive cost. There are distributed generation and storage technologies that produce and store power, including fuel cells, microturbines, wind turbines, solar cells, and batteries. Advances in technology or changes in laws or regulations could reduce the cost of these or other alternative methods of producing power to a level that is competitive with that of most central station power electric production or result in smaller-scale, more fuel efficient, and/or more cost effective distributed generation that allows for increased self-generation by customers. Broader use of distributed generation by retail energy customers may also result from customers' changing perceptions of the merits of utilizing existing generation technology or tax or other economic incentives. Additionally, a state PSC or legislature may modify certain aspects of the traditional electric operating companies' business as a result of these advances in technology.

It is also possible that rapid advances in central station power generation technology could reduce the value of the current electric generating facilities owned by the traditional electric operating companies and Southern Power. Changes in technology could also alter the channels through which electric customers buy or utilize power, which could reduce the revenues or increase the expenses of Southern Company, the traditional electric operating companies, or Southern Power.

Southern Company Gas' gas marketing services is affected by competition from other energy marketers providing similar services in Southern Company Gas' service territories, most notably in Illinois and Georgia. Southern Company Gas' wholesale gas services competes for sales with national and regional full-service energy providers, energy merchants and producers, and pipelines based on the ability to aggregate competitively-priced commodities with transportation and storage capacity. Southern Company Gas competes with natural gas facilities in the Gulf Coast region of the U.S., as the majority of the existing and proposed high deliverability salt-dome natural gas storage facilities in North America are located in the Gulf Coast region.

If new technologies become cost competitive and achieve sufficient scale, the market share of the traditional electric operating companies, Southern Power, and Southern Company Gas could be eroded, and the value of their respective electric generating facilities or natural gas distribution and storage facilities could be reduced. Additionally, Southern Company Gas' market share could be reduced if Southern Company Gas cannot remain price competitive in its unregulated markets. If state PSCs or other applicable state regulatory agencies fail to adjust rates to reflect the impact of any changes in loads, increasing self-generation, and the growth of distributed generation, the financial condition, results of operations, and cash flows of Southern Company and the affected traditional electric operating company or Southern Company Gas could be materially adversely affected.

**Failure to attract and retain an appropriately qualified workforce could negatively impact Southern Company's and its subsidiaries' results of operations.**

Events such as an aging workforce without appropriate replacements, mismatch of skill sets to future needs, or unavailability of contract resources may lead to operating challenges such as lack of resources, loss of knowledge, and a lengthy time period associated with skill development, including with the workforce needs associated with major construction projects and ongoing operations. The Southern Company system's costs, including costs for contractors to replace employees, productivity costs, and safety costs, may rise. Failure to hire and adequately obtain replacement employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect Southern Company and its subsidiaries' ability to manage and operate their businesses. If Southern Company and its subsidiaries are unable to successfully attract and retain an appropriately qualified workforce, results of operations could be negatively impacted.

## CONSTRUCTION RISKS

**The registrants may incur additional costs or delays in the construction of new plants or other facilities and may not be able to recover their investments. Also, existing facilities of the traditional electric operating companies, Southern Power, and Southern Company Gas require ongoing capital expenditures, including those to meet environmental standards.**

### General

The businesses of the registrants require substantial capital expenditures for investments in new facilities and, for the traditional electric operating companies, capital improvements to transmission, distribution, and generation facilities, and, for Southern Company Gas, capital improvements to natural gas distribution and storage facilities, including those to meet environmental standards. Certain of the traditional electric operating companies and Southern Power are in the process of constructing new generating facilities and adding environmental controls equipment at existing generating facilities. Southern Company Gas is replacing certain pipelines in its natural gas distribution system and is involved in two new gas pipeline construction projects. The Southern Company system intends to continue its strategy of developing and constructing other new facilities, expanding or updating existing facilities, and adding environmental control equipment. These types of projects are long term in nature and in some cases include the development and construction of facilities with designs that have not been finalized or previously constructed. The completion of these types of projects without delays or significant cost overruns is subject to substantial risks, including:

- shortages and inconsistent quality of equipment, materials, and labor;
- changes in labor costs and productivity;
- work stoppages;
- contractor or supplier delay or non-performance under construction, operating, or other agreements or non-performance by other major participants in construction projects;
- delays in or failure to receive necessary permits, approvals, tax credits, and other regulatory authorizations;
- delays associated with start-up activities, including major equipment failure and system integration, and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by any PSC or other applicable state regulatory agency);

- operational readiness, including specialized operator training and required site safety programs;
- impacts of new and existing laws and regulations, including environmental laws and regulations;
- the outcome of legal challenges to projects, including legal challenges to regulatory approvals;
- failure to construct in accordance with permitting and licensing requirements;
- failure to satisfy any environmental performance standards and the requirements of tax credits and other incentives;
- continued public and policymaker support for such projects;
- adverse weather conditions or natural disasters;
- other unforeseen engineering or design problems;
- changes in project design or scope;
- environmental and geological conditions;
- delays or increased costs to interconnect facilities to transmission grids; and
- unanticipated cost increases, including materials and labor, and increased financing costs as a result of changes in market interest rates or as a result of construction schedule delays.

If a traditional electric operating company, Southern Power, or Southern Company Gas is unable to complete the development or construction of a project or decides to delay or cancel construction of a project, it may not be able to recover its investment in that project and may incur substantial cancellation payments under equipment purchase orders or construction contracts. Additionally, each Southern Company Gas pipeline construction project involves separate joint venture participants, Southern Power participates in partnership agreements with respect to renewable energy projects, and Georgia Power jointly owns Plant Vogtle Units 3 and 4 with other co-owners. Any failure by a partner or co-owner to perform its obligations under the applicable agreements could have a material negative impact on the applicable project under construction. In addition, partnership and joint ownership agreements may provide partners or co-owners with certain decision-making authority in connection with projects under construction.

Even if a construction project (including a joint venture construction project) is completed, the total costs may be higher than estimated and may not be recoverable through regulated rates, if applicable. In addition, construction delays and contractor performance shortfalls can result in the loss of revenues and may, in turn, adversely affect the net income and financial position of the affected registrant.

Construction delays could result in the loss of otherwise available investment tax credits, PTCs, and other tax incentives. Furthermore, if construction projects are not completed according to specification, a traditional electric operating company, Southern Power, or Southern Company Gas and Southern Company may incur liabilities and suffer reduced plant efficiency, higher operating costs, and reduced net income.

Once facilities become operational, ongoing capital expenditures are required to maintain reliable levels of operation. Significant portions of the traditional electric operating companies' existing facilities were constructed many years ago. Older equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to maintain efficiency, to comply with changing environmental requirements, or to provide safe and reliable operations.

The largest construction project currently underway in the Southern Company system is Plant Vogtle Units 3 and 4.

**Plant Vogtle Units 3 and 4 construction and rate recovery**

In 2009, the Georgia PSC certified construction of Plant Vogtle Units 3 and 4. In 2012, the NRC issued the related combined construction and operating licenses, which allowed full construction of the two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities to begin. Until March 2017, construction on Plant Vogtle Units 3 and 4 continued under a substantially fixed price engineering, procurement, and construction agreement, pursuant to which the EPC Contractor agreed to design, engineer, procure, construct, and test Plant Vogtle Units 3 and 4. On March 29, 2017, the EPC Contractor filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code.

In connection with the EPC Contractor's bankruptcy filing, Georgia Power, acting for itself and as agent for the Vogtle Owners, entered into an agreement with the EPC Contractor to allow construction to continue (Interim Assessment Agreement). The Interim Assessment Agreement expired on July 27, 2017 upon the effectiveness of a services agreement between the Vogtle Owners and the EPC Contractor for the EPC Contractor to transition construction management of Plant Vogtle Units 3 and 4 to Southern Nuclear and to provide ongoing design, engineering, and procurement services to Southern Nuclear (Vogtle Services Agreement). In August 2017, following completion of comprehensive cost to complete and cancellation cost assessments, Georgia Power filed its seventeenth Vogtle Construction Monitoring (VCM) report with the Georgia PSC, which included a recommendation to continue construction of Plant Vogtle Units 3 and 4, with Southern Nuclear serving as project manager and Bechtel Power Corporation (Bechtel) serving as the primary construction contractor. Facility design and engineering remains the responsibility of the EPC Contractor under the Vogtle Services Agreement. The construction completion agreement between Georgia Power, for itself and as agent for the other Vogtle Owners, and Bechtel (Bechtel Agreement) is a cost reimbursable plus fee arrangement, whereby Bechtel will be reimbursed for actual costs plus a base fee and an at-risk fee, which is subject to adjustment based on Bechtel's performance against cost and schedule targets.

On November 2, 2017, the Vogtle Owners entered into an amendment to their joint ownership agreements for Plant Vogtle Units 3 and 4 (as amended, Vogtle Joint Ownership Agreements) to provide for, among other conditions, additional Vogtle Owner approval requirements. Pursuant to the Vogtle Joint Ownership Agreements, the holders of at least 90% of the ownership interests in Plant Vogtle Units 3 and 4 must vote to continue construction if certain adverse events occur, including (i) the bankruptcy of Toshiba Corporation; (ii) termination or rejection in bankruptcy of certain agreements, including the Vogtle Services Agreement or the Bechtel Agreement; (iii) the Georgia PSC or Georgia Power determines that any of Georgia Power's costs relating to the construction of Plant Vogtle Units 3 and 4 will not be recovered in retail rates because such costs are deemed unreasonable or imprudent; or (iv) an increase in the construction budget contained in the seventeenth VCM report of more than $1 billion or extension of the project schedule contained in the seventeenth VCM report of more than one year. In addition, pursuant to the Vogtle Joint Ownership Agreements, the required approval of holders of ownership interests in Plant Vogtle Units 3 and 4 is at least (i) 90% for a change of the primary construction contractor and (ii) 67% for material amendments to the Vogtle Services Agreement or agreements with Southern Nuclear or the primary construction contractor, including the Bechtel Agreement.

On December 21, 2017, the Georgia PSC voted to approve (and issued its related order on January 11, 2018) Georgia Power's recommendation to continue construction and resolved the following regulatory matters related to Plant Vogtle Units 3 and 4: (i) none of the $3.3 billion of costs incurred through December 31, 2015 and reflected in the fourteenth VCM report should be disallowed from rate base on the basis of imprudence; (ii) the December 31, 2015 agreement between Westinghouse and the Vogtle Owners resolving disputes between the Vogtle Owners and the EPC Contractor under the original engineering, procurement, and construction agreement for Plant Vogtle Units 3 and 4 (Contractor Settlement Agreement) was reasonable and prudent and none of the amounts paid pursuant to the Contractor Settlement Agreement should be disallowed from rate base on the basis of imprudence; (iii) (a) capital costs incurred up to $5.680 billion would be presumed to be reasonable and prudent with the burden of proof on any party challenging such costs, (b) Georgia Power would have the burden to show that any capital costs above $5.680 billion were prudent, and (c) a revised capital cost forecast of $7.3 billion (after reflecting the impact of payments received under the Guarantee Settlement Agreement and the Customer Refunds, each as defined below) is found reasonable; (iv) construction of Plant Vogtle Units 3 and 4 should be completed, with Southern Nuclear serving as project manager and Bechtel as primary contractor; (v) approved and deemed reasonable Georgia Power's revised schedule placing Plant Vogtle Units 3 and 4 in service in November 2021 and November 2022, respectively; (vi) confirmed that the revised cost forecast does not represent a cost cap and that prudence decisions on cost recovery will be made at a later date, consistent with applicable Georgia law; (vii) reduced the return on equity (ROE) used to calculate the Nuclear Construction Cost Recovery (NCCR) tariff (a) from 10.95% (the ROE rate setting point authorized by the Georgia PSC in the 2013 Alternative Rate Plan) to 10.00% effective January 1, 2016, (b) from 10.00% to 8.30%, effective January 1, 2020, and (c) from 8.30% to 5.30%, effective January 1, 2021 (provided that the ROE in no case will be less than Georgia Power's average cost of long-term debt); (viii) reduced the ROE used for allowance for funds used during construction equity for Plant Vogtle Units 3 and 4 from 10.00% to Georgia Power's average cost of long-term debt, effective January 1, 2018; and (ix) agreed that upon Unit 3 reaching commercial operation, retail base rates would be adjusted to include carrying costs on those capital costs deemed prudent in the settlement agreement approved by the Georgia PSC on December 20, 2016. The January 11, 2018 order also stated that if Plant Vogtle Units 3 and 4 are not commercially operational by June 1, 2021 and June 1, 2022, respectively, the ROE used to calculate the NCCR tariff will be further reduced by 10 basis points each month (but not lower than Georgia Power's average cost of long-term debt) until the respective unit is commercially operational. In its January 11, 2018 order, the Georgia PSC stated if other certain conditions and assumptions upon which Georgia Power's seventeenth VCM report are based do not materialize, both Georgia Power and the Georgia PSC reserve the right to reconsider the decision to continue construction.

On February 12, 2018, Georgia Interfaith Power & Light, Inc. and Partnership for Southern Equity, Inc. filed a petition appealing the Georgia PSC's January 11, 2018 order with the Fulton County Superior Court. Georgia Power believes the appeal has no merit; however, an adverse outcome in this appeal could have a material impact on Southern Company's and Georgia Power's results of operations, financial condition, and liquidity.

Georgia Power expects Plant Vogtle Units 3 and 4 to be placed in service by November 2021 and November 2022, respectively. Georgia Power's revised capital cost forecast for its 45.7% proportionate share of Plant Vogtle Units 3 and 4 is $8.8 billion ($7.3 billion after reflecting the impact of payments received under a settlement agreement regarding Toshiba's guarantee of certain obligations of the EPC Contractor (Guarantee Settlement Agreement) and certain refunds to customers ordered by the Georgia PSC (Customer Refunds)). Georgia Power's construction work in progress balance for Plant Vogtle Units 3 and 4 was $3.3 billion at December 31, 2017, which is net of the Guarantee Settlement Agreement payments less the Customer Refunds. Georgia Power estimates that its financing costs for construction of Plant Vogtle Units 3 and 4 will total approximately $3.1 billion, of which $1.6 billion had been incurred through December 31, 2017.

As construction continues, challenges with management of contractors, subcontractors, and vendors, labor productivity and availability, fabrication, delivery, assembly, and installation of plant systems, structures, and components (some of which are based on new technology and have not yet operated in the global nuclear industry at this scale), or other issues could arise and change the projected schedule and estimated cost.

There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4 at the federal and state level and additional challenges may arise. Processes are in place that are designed to assure compliance with the requirements specified in the Westinghouse Design Control Document and the combined construction and operating licenses, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance matters, including the timely resolution of Inspections, Tests, Analyses, and Acceptance Criteria and the related approvals by the NRC, may arise, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs.

The ultimate outcome of these matters cannot be determined at this time.

See Note 3 to the financial statements of Southern Company under "Nuclear Construction" and of Georgia Power under "Retail Regulatory Matters - Nuclear Construction" for additional information regarding Plant Vogtle Units 3 and 4.

**Southern Company Gas' significant investments in pipelines and pipeline development projects involve financial and execution risks.**

Southern Company Gas has made significant investments in existing pipelines and pipeline development projects. Many of the existing pipelines are, and when completed many of the pipeline development projects will be, operated by third parties. If one of these agents fails to perform in a proper manner, the value of the investment could decline and Southern Company Gas could lose part or all of the investment. In addition, from time to time, Southern Company Gas may be required to contribute additional capital to a pipeline joint venture or guarantee the obligations of such joint venture.

With respect to certain pipeline development projects, Southern Company Gas will rely on its joint venture partners for construction management and will not exercise direct control over the process. All of the pipeline development projects are dependent on contractors for the successful and timely completion of the projects. Further, the development of pipeline projects involves numerous regulatory, environmental, construction, safety, political, and legal uncertainties and may require the expenditure of significant amounts of capital. These projects may not be completed on schedule, at the budgeted cost, or at all. There may be cost overruns and construction difficulties that cause Southern Company Gas' capital expenditures to exceed its initial expectations. Moreover, Southern Company Gas' revenues will not increase immediately upon the expenditure of funds on a pipeline project. Pipeline construction occurs over an extended period of time and Southern Company Gas will not receive material increases in revenues until the project is placed in service.

The occurrence of any of the foregoing events could adversely affect the results of operations, cash flows, and financial condition of Southern Company Gas and Southern Company.

## FINANCIAL, ECONOMIC, AND MARKET RISKS

**The electric generation and energy marketing operations of the traditional electric operating companies and Southern Power and the natural gas operations of Southern Company Gas are subject to risks, many of which are beyond their control, including changes in energy prices and fuel costs, which may reduce revenues and increase costs.**

The generation, energy marketing, and natural gas operations of the Southern Company system are subject to changes in energy prices and fuel costs, which could increase the cost of producing power, decrease the amount received from the sale of energy, and/or make electric generating facilities less competitive. The market prices for these commodities may fluctuate significantly over relatively short periods of time. Among the factors that could influence energy prices and fuel costs are:

- prevailing market prices for coal, natural gas, uranium, fuel oil, biomass, and other fuels, as applicable, used in the generation facilities of the traditional electric operating companies and Southern Power and, in the case of natural gas, distributed by Southern Company Gas, including associated transportation costs, and supplies of such commodities;
- demand for energy and the extent of additional supplies of energy available from current or new competitors;
- liquidity in the general wholesale electricity and natural gas markets;
- weather conditions impacting demand for electricity and natural gas;
- seasonality;
- transmission or transportation constraints, disruptions, or inefficiencies;
- availability of competitively priced alternative energy sources;
- forced or unscheduled plant outages for the Southern Company system, its competitors, or third party providers;
- the financial condition of market participants;

- the economy in the Southern Company system's service territory, the nation, and worldwide, including the impact of economic conditions on demand for electricity and the demand for fuels, including natural gas;
- natural disasters, wars, embargos, acts of terrorism, and other catastrophic events; and
- federal, state, and foreign energy and environmental regulation and legislation.

Certain of these factors could increase the expenses of the traditional electric operating companies, Southern Power, or Southern Company Gas and Southern Company. For the traditional electric operating companies and Southern Company Gas' regulated gas distribution operations, such increases may not be fully recoverable through rates. Other of these factors could reduce the revenues of the traditional electric operating companies, Southern Power, or Southern Company Gas and Southern Company.

Historically, the traditional electric operating companies and Southern Company Gas from time to time have experienced underrecovered fuel and/or purchased gas cost balances and may experience such balances in the future. While the traditional electric operating companies and Southern Company Gas are generally authorized to recover fuel and/or purchased gas costs through cost recovery clauses, recovery may be denied if costs are deemed to be imprudently incurred, and delays in the authorization of such recovery could negatively impact the cash flows of the affected traditional electric operating company or Southern Company Gas and Southern Company.

**The registrants are subject to risks associated with a changing economic environment, customer behaviors, including increased energy conservation, and adoption patterns of technologies by the customers of the traditional electric operating companies, Southern Power, and Southern Company Gas.**

The consumption and use of energy are fundamentally linked to economic activity. This relationship is affected over time by changes in the economy, customer behaviors, and technologies. Any economic downturn could negatively impact customer growth and usage per customer, thus reducing the sales of energy and revenues. Additionally, any economic downturn or disruption of financial markets, both nationally and internationally, could negatively affect the financial stability of customers and counterparties of the traditional electric operating companies, Southern Power, and Southern Company Gas.

Outside of economic disruptions, changes in customer behaviors in response to energy efficiency programs, changing conditions and preferences, or changes in the adoption of technologies could affect the relationship of economic activity to the consumption of energy.

Both federal and state programs exist to influence how customers use energy, and several of the traditional electric operating companies and Southern Company Gas have PSC or other applicable state regulatory agency mandates to promote energy efficiency. Conservation programs could impact the financial results of the registrants in different ways. For example, if any traditional electric operating company or Southern Company Gas is required to invest in conservation measures that result in reduced sales from effective conservation, regulatory lag in adjusting rates for the impact of these measures could have a negative financial impact on such traditional electric operating company or Southern Company Gas and Southern Company. Customers could also voluntarily reduce their consumption of energy in response to decreases in their disposable income, increases in energy prices, or individual conservation efforts.

In addition, the adoption of technology by customers can have both positive and negative impacts on sales. Many new technologies utilize less energy than in the past. However, new electric and natural gas technologies such as electric and natural gas vehicles can create additional demand. The Southern Company system uses best available methods and experience to incorporate the effects of changes in customer behavior, state and federal programs, PSC or other applicable state regulatory agency mandates, and technology, but the Southern Company system's planning processes may not appropriately estimate and incorporate these effects.

All of the factors discussed above could adversely affect Southern Company's, the traditional electric operating companies', Southern Power's, and/or Southern Company Gas' results of operations, financial condition, and liquidity.

**The operating results of the registrants are affected by weather conditions and may fluctuate on a seasonal and quarterly basis. In addition, catastrophic events, such as fires, earthquakes, hurricanes, tornadoes, floods, droughts, and storms, could result in substantial damage to or limit the operation of the properties of the traditional electric operating companies, Southern Power, and/or Southern Company Gas and could negatively impact results of operation, financial condition, and liquidity.**

Electric power and natural gas supply are generally seasonal businesses. In many parts of the country, demand for power peaks during the summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter months. In most of the areas the traditional electric operating companies serve, electric power sales peak during the summer with a smaller peak during the winter, while in most of the areas Southern Company Gas serves, natural gas demand peaks during the winter. As a result, the overall operating results of the registrants may fluctuate substantially on a seasonal basis. In addition, the traditional electric operating companies, Southern Power, and Southern Company Gas have historically sold less power and natural gas when weather conditions are milder. Unusually mild weather in the future could reduce the revenues, net income, and available cash of the affected registrant.

Further, volatile or significant weather events could result in substantial damage to the transmission and distribution lines of the traditional electric operating companies, the generating facilities of the traditional electric operating companies and Southern Power, and the natural gas distribution and storage facilities of Southern Company Gas. The traditional electric operating companies, Southern Power, and Southern Company Gas have significant investments in the Atlantic and Gulf Coast regions and Southern Power has wind and natural gas investments in various states which could be subject to severe weather, as well as solar investments in various states which could be subject to natural disasters. Further, severe drought conditions can reduce the availability of water and restrict or prevent the operation of certain generating facilities.

In the event a traditional electric operating company or Southern Company Gas experiences any of these weather events or any natural disaster or other catastrophic event, recovery of costs in excess of reserves and insurance coverage is subject to the approval of its state PSC or other applicable state regulatory agency. Historically, the traditional electric operating companies from time to time have experienced deficits in their storm cost recovery reserve balances and may experience such deficits in the future. Any denial by the applicable state PSC or other applicable state regulatory agency or delay in recovery of any portion of such costs could have a material negative impact on a traditional electric operating company's or Southern Company Gas' and Southern Company's results of operations, financial condition, and liquidity.

In addition, damages resulting from significant weather events within the service territory of any traditional electric operating company or Southern Company Gas or affecting Southern Power's customers may result in the loss of customers and reduced demand for energy for extended periods. Any significant loss of customers or reduction in demand for energy could have a material negative impact on a traditional electric operating company's, Southern Power's, or Southern Company Gas' and Southern Company's results of operations, financial condition, and liquidity.

**Acquisitions, dispositions, or other strategic ventures or investments may not result in anticipated benefits and may present risks not originally contemplated, which may have a material adverse effect on the liquidity, results of operations, and financial condition of Southern Company and its subsidiaries.**

Southern Company and its subsidiaries have made significant acquisitions and investments in the past and may in the future make additional acquisitions, dispositions, or other strategic ventures or investments, including the proposed sale by Pivotal Utility Holdings, a wholly-owned subsidiary of Southern Company Gas, of the assets of its natural gas distribution utilities, Elizabethtown Gas and Elkton Gas, and the potential sale by Southern Power of a 33% equity interest in a newly-formed holding company that owns substantially all of Southern Power's solar assets. Southern Company and its subsidiaries continually seek opportunities to create value through various transactions, including acquisitions or sales of assets. Specifically, Southern Power continually seeks opportunities to execute its strategy to create value through various transactions, including acquisitions and sales of assets, development and construction of new generating facilities, and entry into PPAs primarily with investor-owned utilities, independent power producers, municipalities, and other load-serving entities, as well as commercial and industrial customers.

Southern Company and its subsidiaries may face significant competition for transactional opportunities and anticipated transactions may not be completed on acceptable terms or at all. In addition, these transactions are intended to, but may not, result in the generation of cash or income, the realization of savings, the creation of efficiencies, or the reduction of risk. These transactions may also affect the liquidity, results of operations, and financial condition of Southern Company and its subsidiaries.

These transactions also involve risks, including:

- they may not result in an increase in income or provide an adequate return on capital or other anticipated benefits;
- they may result in Southern Company or its subsidiaries entering into new or additional lines of business, which may have new or different business or operational risks;
- they may not be successfully integrated into the acquiring company's operations and/or internal control processes;
- the due diligence conducted prior to a transaction may not uncover situations that could result in financial or legal exposure or the acquiring company may not appropriately evaluate the likelihood or quantify the exposure from identified risks;
- they may result in decreased earnings, revenues, or cash flow;
- expected benefits of a transaction may be dependent on the cooperation or performance of a counterparty; or
- for the traditional electric operating companies and Southern Company Gas, costs associated with such investments that were expected to be recovered through rates may not be recoverable.

**Southern Company and Southern Company Gas are holding companies and are dependent on cash flows from their respective subsidiaries to meet their ongoing and future financial obligations, including making interest and principal payments on outstanding indebtedness and, for Southern Company, to pay dividends on its common stock.**

Southern Company and Southern Company Gas are holding companies and, as such, they have no operations of their own. Substantially all of Southern Company's and Southern Company Gas' respective consolidated assets are held by subsidiaries. A significant portion of Southern Company Gas' debt is issued by its 100%-owned subsidiary, Southern Company Gas Capital, and is fully and unconditionally guaranteed by Southern Company Gas. Southern Company's and Southern Company Gas' ability to meet their respective financial obligations, including making interest and principal payments on outstanding indebtedness, and, for Southern Company, to pay dividends on its common stock, is primarily dependent on the net income and cash flows of their respective subsidiaries and the ability of those subsidiaries to pay upstream dividends or to repay borrowed funds. Prior to funding Southern Company or Southern Company Gas, the respective subsidiaries have regulatory restrictions and financial obligations that must be satisfied, including among others, debt service and preferred stock dividends. These subsidiaries are separate legal entities and have no obligation to provide Southern Company or Southern Company Gas with funds. In addition, Southern Company and Southern Company Gas may provide capital contributions or debt financing to subsidiaries under certain circumstances, which would reduce the funds available to meet their respective financial obligations, including making interest and principal payments on outstanding indebtedness, and to pay dividends on Southern Company's common stock.

**A downgrade in the credit ratings of any of the registrants, Southern Company Gas Capital, or Nicor Gas could negatively affect their ability to access capital at reasonable costs and/or could require posting of collateral or replacing certain indebtedness.**

There are a number of factors that rating agencies evaluate to arrive at credit ratings for the registrants, Southern Company Gas Capital, and Nicor Gas, including capital structure, regulatory environment, the ability to cover liquidity requirements, and other commitments for capital. The registrants, Southern Company Gas Capital, and Nicor Gas could experience a downgrade in their ratings if any rating agency concludes that the level of business or financial risk of the industry or the applicable company has deteriorated. Changes in ratings methodologies by the agencies could also have a negative impact on credit ratings. If one or more rating agencies downgrade any registrant, Southern Company Gas Capital, or Nicor Gas, borrowing costs likely would increase, including automatic increases in interest rates under applicable term loans and credit facilities, the pool of investors and funding sources would likely decrease, and, particularly for any downgrade to below investment grade, significant collateral requirements may be triggered in a number of contracts. Any credit rating downgrades could require altering the mix of debt financing currently used, and could require the issuance of secured indebtedness and/or indebtedness with additional restrictive covenants binding the applicable company.

**Uncertainty in demand for energy can result in lower earnings or higher costs. If demand for energy falls short of expectations, it could result in potentially stranded assets. If demand for energy exceeds expectations, it could result in increased costs for purchasing capacity in the open market or building additional electric generation and transmission facilities or natural gas distribution and storage facilities.**

Southern Company, the traditional electric operating companies, and Southern Power each engage in a long-term planning process to estimate the optimal mix and timing of new generation assets required to serve future load obligations. Southern Company Gas engages in a long-term planning process to estimate the optimal mix and timing of building new pipelines and storage facilities, replacing existing pipelines, rewatering storage facilities, and entering new markets and/or expanding in existing markets. These planning processes must look many years into the future in order to accommodate the long lead times associated with the permitting and construction of new generation and associated transmission facilities and natural gas distribution and storage facilities. Inherent risk exists in predicting demand this far into the future as these future loads are dependent on many uncertain factors, including economic conditions, customer usage patterns, efficiency programs, and customer technology adoption. Because regulators may not permit the traditional electric operating companies or Southern Company Gas' regulated operating companies to adjust rates to recover the costs of new generation and associated transmission assets and/or new pipelines and related infrastructure in a timely manner or at all, Southern Company and its subsidiaries may not be able to fully recover these costs or may have exposure to regulatory lag associated with the time between the incurrence of costs and the recovery in customers' rates. In addition, under Southern Power's model of selling capacity and energy at negotiated market-based rates under long-term PPAs, Southern Power might not be able to fully execute its business plan if market prices drop below original forecasts. Southern Power and/or the traditional electric operating companies may not be able to extend existing PPAs or find new buyers for existing generation assets as existing PPAs expire, or they may be forced to market these assets at prices lower than originally intended. These situations could have negative impacts on net income and cash flows for the affected registrant.

The traditional electric operating companies are currently obligated to supply power to retail customers and wholesale customers under long-term PPAs. Southern Power is currently obligated to supply power to wholesale customers under long-term PPAs. At peak times, the demand for power required to meet this obligation could exceed the Southern Company system's available generation capacity. Market or competitive forces may require that the traditional electric operating companies purchase capacity on the open market or build additional generation and transmission facilities, and for Southern Power to purchase energy or capacity on the open market. Because regulators may not permit the traditional electric operating companies to pass all of these purchase or construction costs on to their customers, the traditional electric operating companies may not be able to recover some or all of these costs or may have exposure to regulatory lag associated with the time between the incurrence of costs of purchased or constructed capacity and the traditional electric operating companies' recovery in customers' rates. Under Southern Power's long-term fixed price PPAs, Southern Power may not be able to recover all of these costs. These situations could have negative impacts on net income and cash flows for the affected registrant.

**The businesses of the registrants and Nicor Gas are dependent on their ability to successfully access funds through capital markets and financial institutions. The inability of any of the registrants or Nicor Gas to access funds may limit its ability to execute its business plan by impacting its ability to fund capital investments or acquisitions that it may otherwise rely on to achieve future earnings and cash flows.**

The registrants and Nicor Gas rely on access to both short-term money markets and longer-term capital markets as a significant source of liquidity for capital requirements not satisfied by the cash flow from their respective operations. If any of the registrants or Nicor Gas is not able to access capital at competitive rates or on favorable terms, its ability to implement its business plan will be limited by impacting its ability to fund capital investments or acquisitions that it may otherwise rely on to achieve future earnings and cash flows. In addition, the registrants and Nicor Gas rely on committed bank lending agreements as back-up liquidity which allows them to access low cost money markets. Each of the registrants and Nicor Gas believes that it will maintain sufficient access to these financial markets based upon current credit ratings. However, certain events or market disruptions may increase the cost of borrowing or adversely affect the ability to raise capital through the issuance of securities or other borrowing arrangements or the ability to secure committed bank lending agreements used as back-up sources of capital. Such disruptions could include:

- an economic downturn or uncertainty;
- bankruptcy or financial distress at an unrelated energy company, financial institution, or sovereign entity;
- capital markets volatility and disruption, either nationally or internationally;
- changes in tax policy;
- volatility in market prices for electricity and natural gas;
- terrorist attacks or threatened attacks on the Southern Company system's facilities or unrelated energy companies' facilities;
- war or threat of war; or
- the overall health of the utility and financial institution industries.

As of December 31, 2017, Mississippi Power's current liabilities exceeded current assets by approximately $911 million primarily due to a $900 million unsecured term loan that matures on March 31, 2018. Mississippi Power expects to refinance the unsecured term loan with external security issuances and/or borrowings from financial institutions or Southern Company. Mississippi Power has been informed by Southern Company that in the event sufficient funds are not available from external sources, Southern Company intends to provide Mississippi Power with loans and/or equity to fund the remaining indebtedness to mature and other cash needs over the next 12 months.

Georgia Power's ability to make future borrowings through its term loan credit facility with the Federal Financing Bank is subject to the satisfaction of customary conditions, as well as certification of compliance with the requirements of the loan guarantee program under Title XVII of the Energy Policy Act of 2005, including accuracy of project-related representations and warranties, delivery of updated project-related information and evidence of compliance with the prevailing wage requirements of the Davis-Bacon Act of 1931, as amended, and certification from the DOE's consulting engineer that proceeds of the advances are used to reimburse certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Title XVII Loan Guarantee Program. Prior to obtaining any further advances under Georgia Power's loan guarantee agreement with the DOE, Georgia Power is required to obtain the DOE's approval of the Bechtel Agreement.

**Failure to comply with debt covenants or conditions could adversely affect the ability of the registrants, Southern Company Gas Capital, or Nicor Gas to execute future borrowings.**

The debt and credit agreements of the registrants, Southern Company Gas Capital, and Nicor Gas contain various financial and other covenants. Georgia Power's loan guarantee agreement with the DOE contains additional covenants, events of default, and mandatory prepayment events relating to the construction of Plant Vogtle Units 3 and 4. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements, which would negatively affect the applicable company's financial condition and liquidity.

**Volatility in the securities markets, interest rates, and other factors could substantially increase defined benefit pension and other postretirement plan costs and the costs of nuclear decommissioning.**

The costs of providing pension and other postretirement benefit plans are dependent on a number of factors, such as the rates of return on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plan, changes in actuarial assumptions, future government regulation, changes in life expectancy, and the frequency and amount of the Southern Company system's required or voluntary contributions made to the plans. Changes in actuarial assumptions and differences between the assumptions and actual values, as well as a significant decline in the value of investments that fund the pension and other postretirement plans, if not offset or mitigated by a decline in plan liabilities, could increase pension and other postretirement expense, and the Southern Company system could be required from time to time to fund the pension plans with significant amounts of cash. Such cash funding obligations could have a material impact on liquidity by reducing cash flows and could negatively affect results of operations. Additionally, Alabama Power and Georgia Power each hold significant assets in their nuclear decommissioning trusts to satisfy obligations to decommission Alabama Power's and Georgia Power's nuclear plants. The rate of return on assets held in those trusts can significantly impact both the costs of decommissioning and the funding requirements for the trusts.

**The registrants are subject to risks associated with their ability to obtain adequate insurance at acceptable costs.**

The financial condition of some insurance companies, the threat of terrorism, and natural disasters, among other things, could have disruptive effects on insurance markets. The availability of insurance covering risks that the registrants and their respective competitors typically insure against may decrease, and the insurance that the registrants are able to obtain may have higher deductibles, higher premiums, and more restrictive policy terms. Further, the insurance policies may not cover all of the potential exposures or the actual amount of loss incurred.

Any losses not covered by insurance, or any increases in the cost of applicable insurance, could adversely affect the results of operations, cash flows, or financial condition of the affected registrant.

**The use of derivative contracts by Southern Company and its subsidiaries in the normal course of business could result in financial losses that negatively impact the net income of the registrants or in reported net income volatility.**

Southern Company and its subsidiaries, including the traditional electric operating companies, Southern Power, and Southern Company Gas, use derivative instruments, such as swaps, options, futures, and forwards, to manage their commodity and interest rate exposures and, to a lesser extent, manage foreign currency exchange rate exposure and engage in limited trading activities. The registrants could recognize financial losses as a result of volatility in the market values of these contracts or if a counterparty fails to perform. These risks are managed through risk management policies, limits, and procedures, which might not work as planned and cannot entirely eliminate the risks associated with these activities. In addition, derivative contracts entered into for hedging purposes might not offset the underlying exposure being hedged as expected, resulting in financial losses. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management's judgment or use of estimates. The factors used in the valuation of these instruments become more difficult to predict and the calculations become less reliable the further into the future these estimates are made. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

In addition, Southern Company Gas utilizes derivative instruments to lock in economic value in wholesale gas services, which may not qualify or are not designated as hedges for accounting purposes. The difference in accounting treatment for the underlying position and the financial instrument used to hedge the value of the contract can cause volatility in reported net income of Southern Company and Southern Company Gas while the positions are open due to mark-to-market accounting.

**Future impairments of goodwill or long-lived assets could have a material adverse effect on the registrants' results of operations.**

Goodwill is assessed for impairment at least annually and more frequently if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value and long-lived assets are assessed for impairment whenever events or circumstances indicate that an asset's carrying amount may not be recoverable. In connection with the completion of the Merger, the application of the acquisition method of accounting was pushed down to Southern Company Gas. The excess of the purchase price over the fair values of Southern Company Gas' assets and liabilities was recorded as goodwill. This resulted in a significant increase in the goodwill recorded on Southern Company's and Southern Company Gas' consolidated balance sheets. At December 31, 2017, goodwill was $6.3 billion and $6.0 billion for Southern Company and Southern Company Gas, respectively.

In addition, Southern Company and its subsidiaries have long-lived assets recorded on their balance sheets. To the extent the value of goodwill or long-lived assets become impaired, the affected registrant may be required to incur impairment charges that could have a material impact on their results of operations. For example, a wholly-owned subsidiary of Southern Company

Gas owns and operates a natural gas storage facility consisting of two salt dome caverns where recent seismic mapping indicates that proximity of one of the caverns to the edge of the salt dome may be less than the required minimum and could result in Southern Company Gas retiring the cavern early. Early retirement of the cavern could trigger impairment of other long-lived assets associated with the natural gas storage facility. In addition, a subsidiary of Southern Company has several leveraged lease agreements, with terms ranging up to 45 years, which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. Southern Company reviews all important lease assumptions at least annually, or more frequently if events or changes in circumstances indicate that a change in assumptions has occurred or may occur. With respect to Southern Company's subsidiary's investments in leveraged leases, the recovery of its investment is dependent on the profitable operation of the leased assets by the respective lessees. A significant deterioration in the performance of the leased asset could result in the impairment of the related lease receivable.

**Item 1B. UNRESOLVED STAFF COMMENTS.**

None.

**Item 2. PROPERTIES**

**Electric**

***Electric Properties***

The traditional electric operating companies, Southern Power, and SEGCO, at December 31, 2017 , owned and/or operated 33 hydroelectric generating stations, 29 fossil fuel generating stations, three nuclear generating stations, 15 combined cycle/cogeneration stations, 35 solar facilities, eight wind facilities, one biomass facility, and one landfill gas facility. The amounts of capacity for each company, as of December 31, 2017 , are shown in the table below.

| Generating Station | Location | Nameplate Capacity (1) | |
|---|---|---|---|
| | | (KWs) | |
| **FOSSIL STEAM** | | | |
| Gadsden | Gadsden, AL | 120,000 | |
| Gorgas | Jasper, AL | 1,021,250 | |
| Barry | Mobile, AL | 1,300,000 | |
| Greene County | Demopolis, AL | 300,000 | (2) |
| Gaston Unit 5 | Wilsonville, AL | 880,000 | |
| Miller | Birmingham, AL | 2,532,288 | (3) |
| **Alabama Power Total** | | 6,153,538 | |
| Bowen | Cartersville, GA | 3,160,000 | |
| Hammond | Rome, GA | 800,000 | |
| McIntosh | Effingham County, GA | 163,117 | |
| Scherer | Macon, GA | 750,924 | (4) |
| Wansley | Carrollton, GA | 925,550 | (5) |
| Yates | Newnan, GA | 700,000 | |
| **Georgia Power Total** | | 6,499,591 | |
| Crist | Pensacola, FL | 970,000 | |
| Daniel | Pascagoula, MS | 500,000 | (6) |
| Scherer Unit 3 | Macon, GA | 204,500 | (4) |
| **Gulf Power Total** | | 1,674,500 | |
| Daniel | Pascagoula, MS | 500,000 | (6) |
| Greene County | Demopolis, AL | 200,000 | (2) |
| Watson | Gulfport, MS | 862,000 | |
| **Mississippi Power Total** | | 1,562,000 | |
| Gaston Units 1-4 | Wilsonville, AL | | |
| **SEGCO Total** | | 1,000,000 | (7) |
| **Total Fossil Steam** | | 16,889,629 | |
| **NUCLEAR STEAM** | | | |
| Farley | Dothan, AL | | |
| **Alabama Power Total** | | 1,720,000 | |
| Hatch | Baxley, GA | 899,612 | (8) |
| Vogtle Units 1 and 2 | Augusta, GA | 1,060,240 | (9) |
| **Georgia Power Total** | | 1,959,852 | |
| **Total Nuclear Steam** | | 3,679,852 | |
| **COMBUSTION TURBINES** | | | |
| Greene County | Demopolis, AL | | |
| **Alabama Power Total** | | 720,000 | |
| Boulevard | Savannah, GA | 19,700 | |

| Generating Station | Location | Nameplate Capacity (1) | |
|---|---|---|---|
| McDonough Unit 3 | Atlanta, GA | 78,800 | |
| McIntosh Units 1 through 8 | Effingham County, GA | 640,000 | |
| McManus | Brunswick, GA | 481,700 | |
| Robins | Warner Robins, GA | 158,400 | |
| Wansley | Carrollton, GA | 26,322 | (5) |
| Wilson | Augusta, GA | 354,100 | |
| **Georgia Power Total** | | 1,759,022 | |
| Lansing Smith Unit A | Southport, FL | 39,400 | |
| Pea Ridge Units 1 through 3 | Pea Ridge, FL | 15,000 | |
| **Gulf Power Total** | | 54,400 | |
| Chevron Cogenerating Station | Pascagoula, MS | 147,292 | (10) |
| Sweatt | Meridian, MS | 39,400 | |
| Watson | Gulfport, MS | 39,360 | |
| **Mississippi Power Total** | | 226,052 | |
| Addison | Thomaston, GA | 668,800 | |
| Cleveland County | Cleveland County, NC | 720,000 | |
| Dahlberg | Jackson County, GA | 756,000 | |
| Oleander | Cocoa, FL | 791,301 | |
| Rowan | Salisbury, NC | 455,250 | |
| **Southern Power Total** | | 3,391,351 | |
| Gaston **(SEGCO)** | Wilsonville, AL | 19,680 | (7) |
| **Total Combustion Turbines** | | 6,170,505 | |
| **COGENERATION** | | | |
| Washington County | Washington County, AL | 123,428 | |
| Lowndes County | Burkeville, AL | 104,800 | |
| Theodore | Theodore, AL | 236,418 | |
| **Alabama Power Total** | | 464,646 | |
| **COMBINED CYCLE** | | | |
| Barry | Mobile, AL | | |
| **Alabama Power Total** | | 1,070,424 | |
| McIntosh Units 10&11 | Effingham County, GA | 1,318,920 | |
| McDonough-Atkinson Units 4 through 6 | Atlanta, GA | 2,520,000 | |
| **Georgia Power Total** | | 3,838,920 | |
| Lansing Smith Unit 3 | Southport, FL | | |
| **Gulf Power Total** | | 545,500 | |

| Generating Station | Location | Nameplate Capacity (1) | |
|---|---|---|---|
| Daniel | Pascagoula, MS | 1,070,424 | |
| Kemper County/Ratcliffe | Kemper County, MS | 769,898 | (11) |
| **Mississippi Power Total** | | 1,840,322 | |
| Franklin | Smiths, AL | 1,857,820 | |
| Harris | Autaugaville, AL | 1,318,920 | |
| Mankato | Mankato, MN | 375,000 | |
| Rowan | Salisbury, NC | 530,550 | |
| Stanton Unit A | Orlando, FL | 428,649 | (12) |
| Wansley | Carrollton, GA | 1,073,000 | |
| **Southern Power Total** | | 5,583,939 | |
| **Total Combined Cycle** | | 12,879,105 | |
| **HYDROELECTRIC FACILITIES** | | | |
| Bankhead | Holt, AL | 53,985 | |
| Bouldin | Wetumpka, AL | 225,000 | |
| Harris | Wedowee, AL | 132,000 | |
| Henry | Ohatchee, AL | 72,900 | |
| Holt | Holt, AL | 46,944 | |
| Jordan | Wetumpka, AL | 100,000 | |
| Lay | Clanton, AL | 177,000 | |
| Lewis Smith | Jasper, AL | 157,500 | |
| Logan Martin | Vincent, AL | 135,000 | |
| Martin | Dadeville, AL | 182,000 | |
| Mitchell | Verbena, AL | 170,000 | |
| Thurlow | Tallassee, AL | 81,000 | |
| Weiss | Leesburg, AL | 87,750 | |
| Yates | Tallassee, AL | 47,000 | |
| **Alabama Power Total** | | 1,668,079 | |
| Bartletts Ferry | Columbus, GA | 173,000 | |
| Goat Rock | Columbus, GA | 38,600 | |
| Lloyd Shoals | Jackson, GA | 14,400 | |
| Morgan Falls | Atlanta, GA | 16,800 | |
| North Highlands | Columbus, GA | 29,600 | |
| Oliver Dam | Columbus, GA | 60,000 | |
| Rocky Mountain | Rome, GA | 215,256 | (13) |
| Sinclair Dam | Milledgeville, GA | 45,000 | |
| Tallulah Falls | Clayton, GA | 72,000 | |
| Terrora | Clayton, GA | 16,000 | |
| Tugalo | Clayton, GA | 45,000 | |
| Wallace Dam | Eatonton, GA | 321,300 | |
| Yonah | Toccoa, GA | 22,500 | |
| 6 Other Plants | Various Georgia locations | 18,080 | |
| **Georgia Power Total** | | 1,087,536 | |
| **Total Hydroelectric Facilities** | | 2,755,615 | |

| Generating Station | Location | Nameplate Capacity (1) | |
|---|---|---|---|
| **RENEWABLE SOURCES:** | | | |
| **SOLAR FACILITIES** | | | |
| Fort Benning | Columbus, GA | 30,000 | |
| Fort Gordon | Augusta, GA | 30,000 | |
| Fort Stewart | Fort Stewart, GA | 30,000 | |
| Kings Bay | Camden County, GA | 30,000 | |
| Dalton | Dalton, GA | 6,012 | |
| 3 Other Plants | Various Georgia locations | 2,984 | |
| **Georgia Power Total** | | 128,996 | |
| Adobe | Kern County, CA | 20,000 | |
| Apex | North Las Vegas, NV | 20,000 | |
| Boulder I | Clark County, NV | 100,000 | (14) |
| Butler | Taylor County, GA | 103,700 | |
| Butler Solar Farm | Taylor County, GA | 22,000 | |
| Calipatria | Imperial County, CA | 20,000 | |
| Campo Verde | Imperial County, CA | 147,420 | |
| Cimarron | Springer, NM | 30,640 | |
| Decatur County | Decatur County, GA | 20,000 | |
| Decatur Parkway | Decatur County, GA | 84,000 | |
| Desert Stateline | San Bernadino County, CA | 299,900 | (14) |
| East Pecos | Pecos County, TX | 120,000 | |
| Garland | Kern County, CA | 205,130 | (14) |
| Granville | Oxford, NC | 2,500 | |
| Henrietta | Kings County, CA | 102,000 | (14) |
| Imperial Valley | Imperial County, CA | 163,200 | (14) |
| Lamesa | Dawson County, TX | 102,000 | |
| Lost Hills - Blackwell | Kern County, CA | 33,440 | (14) |
| Macho Springs | Luna County, NM | 55,000 | |
| Morelos del Sol | Kern County, CA | 15,000 | |
| North Star | Fresno County, CA | 61,600 | (14) |
| Pawpaw | Taylor County, GA | 30,480 | |
| Roserock | Pecos County, TX | 160,000 | (14) |
| Rutherford | Rutherford County, NC | 74,800 | |
| Sandhills | Taylor County, GA | 146,890 | |
| Spectrum | Clark County, NV | 30,240 | |
| Tranquillity | Fresno County, CA | 205,300 | (14) |
| **Southern Power Total** | | 2,375,240 | (15) |
| **Total Solar** | | 2,504,236 | |

| Generating Station | Location | Nameplate Capacity (1) | |
|---|---|---|---|
| **WIND FACILITIES** | | | |
| Bethel | Castro County, TX | 276,000 | |
| Grant Plains | Grant County, OK | 147,200 | |
| Grant Wind | Grant County, OK | 151,800 | |
| Kay Wind | Kay County, OK | 299,000 | |
| Passadumkeag | Penobscot County, ME | 42,900 | |
| Salt Fork | Donley & Gray Counties TX | 174,000 | |
| Tyler Bluff | Cooke County, TX | 125,580 | |
| Wake Wind | Crosby & Floyd Counties, TX | 257,250 | (14) |
| **Southern Power Total** | | 1,473,730 | |
| **LANDFILL GAS FACILITY** | | | |
| Perdido | Escambia County, FL | | |
| **Gulf Power Total** | | 3,200 | |
| **BIOMASS FACILITY** | | | |
| Nacogdoches | Sacul, TX | | |
| **Southern Power Total** | | 115,500 | |
| **Total Generating Capacity** | | 46,936,018 | |

**Notes:**

(1) See "Jointly-Owned Facilities" herein for additional information.

(2) Owned by Alabama Power and Mississippi Power as tenants in common in the proportions of 60% and 40%, respectively.

(3) Capacity shown is Alabama Power's portion (95.92%) of total plant capacity.

(4) Capacity shown for Georgia Power is 8.4% of Units 1 and 2 and 75% of Unit 3. Capacity shown for Gulf Power is 25% of Unit 3.

(5) Capacity shown is Georgia Power's portion (53.5%) of total plant capacity.

(6) Represents 50% of Plant Daniel Units 1 and 2, which are owned as tenants in common by Gulf Power and Mississippi Power.

(7) SEGCO is jointly-owned by Alabama Power and Georgia Power. See BUSINESS in Item 1 herein for additional information.

(8) Capacity shown is Georgia Power's portion (50.1%) of total plant capacity.

(9) Capacity shown is Georgia Power's portion (45.7%) of total plant capacity.

(10) Generation is dedicated to a single industrial customer.

(11) The capacity shown is the gross capacity using natural gas fuel without supplemental firing.

(12) Capacity shown is Southern Power's portion (65%) of total plant capacity.

(13) Capacity shown is Georgia Power's portion (25.4%) of total plant capacity. OPC operates the plant.

(14) Each facility is owned by Southern Power through a majority-owned subsidiary (90.1% Wake Wind, 66% Desert Stateline, and 51% for each of the following facilities: Boulder 1, Garland, Henrietta, Imperial Valley, Lost Hills-Blackwell, North Star, Roserock, and Tranquillity). The capacity shown in the table is 100% of the nameplate capacity for the respective facility.

(15) Southern Power is pursuing the sale of a 33% equity interest in a newly-formed holding company that owns substantially all of Southern Power's solar assets, which, if successful, is expected to close in the middle of 2018.

Except as discussed below under "Titles to Property," the principal plants and other important units of the traditional electric operating companies, Southern Power, and SEGCO are owned in fee by the respective companies. It is the opinion of management of each such company that its operating properties are adequately maintained and are substantially in good operating condition, and suitable for their intended purpose.

Mississippi Power owns a 79-mile length of 500-kilovolt transmission line which is leased to Entergy Gulf States Louisiana, LLC. The line, completed in 1984, extends from Plant Daniel to the Louisiana state line. Entergy Gulf States Louisiana, LLC is paying a use fee over a 40-year period covering all expenses and the amortization of the original $57 million cost of the line. At December 31, 2017 , the unamortized portion of this cost was approximately $13 million.

Mississippi Power owns a lignite mine and equipment that were intended to provide fuel for the Kemper IGCC. Mississippi Power also has acquired mineral reserves located around the Kemper County energy facility. The mine, operated by North American Coal Corporation, started commercial operation in 2013. Liberty Fuels Company, LLC, the operator of the mine, has a legal obligation to perform mine reclamation and Mississippi Power has a contractual obligation to fund all reclamation activities. Mississippi Power expects mine reclamation activities to begin in 2018. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Kemper County Energy Facility – Lignite Mine and $CO_2$ Pipeline Facilities" of Mississippi Power in Item 7 herein and Note 3 to the financial statements of Southern Company and Mississippi Power under "Kemper County Energy Facility – Lignite Mine and $CO_2$ Pipeline Facilities" in Item 8 herein for additional information on the lignite mine.

In 2018, Mississippi Power will file a reserve margin plan which could impact Mississippi Power's generating stations as well as the generating stations jointly owned by Mississippi Power and other traditional electric operating companies. See BUSINESS in Item 1 herein under "Rate Matters – Integrated Resource Planning – Mississippi Power" for additional information.

In 2017 , the maximum demand on the traditional electric operating companies, Southern Power, and SEGCO was 34,874,000 KWs and occurred on August 17, 2017 . The all-time maximum demand of 38,777,000 KWs on the traditional electric operating companies, Southern Power, and SEGCO occurred on August 22, 2007. These amounts exclude demand served by capacity retained by MEAG Power, OPC, and SEPA. The reserve margin for the traditional electric operating companies, Southern Power, and SEGCO in 2017 was 30.8%. See SELECTED FINANCIAL DATA in Item 6 herein for additional information.

***Jointly-Owned Facilities***

Alabama Power, Georgia Power, and Southern Power at December 31, 2017 had undivided interests in certain generating plants and other related facilities with non-affiliated parties. The percentages of ownership of the total plant or facility are as follows:

| | | Percentage Ownership | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Total Capacity | Alabama Power | Power South | Georgia Power | OPC | MEAG Power | Dalton | Southern Power | OUC | FMPA | KUA |
| | (MWs) | | | | | | | | | | |
| Plant Miller Units 1 and 2 | 1,320 | 91.8% | 8.2% | —% | —% | —% | —% | —% | —% | —% | —% |
| Plant Hatch | 1,796 | — | — | 50.1 | 30.0 | 17.7 | 2.2 | — | — | — | — |
| Plant Vogtle Units 1 and 2 | 2,320 | — | — | 45.7 | 30.0 | 22.7 | 1.6 | — | — | — | — |
| Plant Scherer Units 1 and 2 | 1,636 | — | — | 8.4 | 60.0 | 30.2 | 1.4 | — | — | — | — |
| Plant Wansley | 1,779 | — | — | 53.5 | 30.0 | 15.1 | 1.4 | — | — | — | — |
| Rocky Mountain | 848 | — | — | 25.4 | 74.6 | — | — | — | — | — | — |
| Plant Stanton A | 660 | — | — | — | — | — | — | 65.0 | 28.0 | 3.5 | 3.5 |

Alabama Power and Georgia Power have contracted to operate and maintain the respective units in which each has an interest (other than Rocky Mountain) as agent for the joint owners. SCS provides operation and maintenance services for Plant Stanton A. Southern Nuclear operates and provides services to Alabama Power's and Georgia Power's nuclear plants.

In addition, Georgia Power has commitments regarding a portion of a 5% interest in Plant Vogtle Units 1 and 2 owned by MEAG Power that are in effect until the later of retirement of the plant or the latest stated maturity date of MEAG Power's bonds issued to finance such ownership interest. The payments for capacity are required whether any capacity is available. The energy cost is a function of each unit's variable operating costs. Except for the portion of the capacity payments related to the Georgia PSC's disallowances of Plant Vogtle Units 1 and 2 costs, the cost of such capacity and energy is included in purchased power from non-affiliates in Georgia Power's statements of income in Item 8 herein. Also see Note 7 to the financial statements of Georgia Power under "Commitments – Fuel and Purchased Power Agreements" in Item 8 herein for additional information.

Construction continues on Plant Vogtle Units 3 and 4, which are jointly owned by the Vogtle Owners (with each owner holding the same undivided ownership interest as shown in the table above with respect to Plant Vogtle Units 1 and 2). See Note 3 to the financial statements of Southern Company and Georgia Power under "Nuclear Construction" and "Retail Regulatory Matters – Nuclear Construction," respectively, in Item 8 herein.

***Titles to Property***

The traditional electric operating companies', Southern Power's, and SEGCO's interests in the principal plants (other than certain pollution control facilities and the land on which five combustion turbine generators of Mississippi Power are located, which is held by easement) and other important units of the respective companies are owned in fee by such companies, subject only to the (1) liens pursuant to pollution control revenue bonds of Gulf Power on specific pollution control facilities at Plant Daniel, (2) liens pursuant to the assumption of debt obligations by Mississippi Power in connection with the acquisition of Plant Daniel Units 3 and 4, (3) liens pursuant to the agreements entered into with Mississippi Power's largest customer, Chevron Products Company (Chevron), on October 4, 2017, on the co-generation assets located at the Chevron refinery, (4) liens associated with Georgia Power's reimbursement obligations to the DOE under its loan guarantee, which are secured by a first priority lien on (a) Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 and (b) Georgia Power's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4, and (5) liens associated with two PPAs assumed as part of the acquisition of the Mankato project in October 2016 by Southern Power Company. See Note 6 to the financial statements of Southern Company, Georgia Power, Gulf Power, Mississippi Power, and Southern Power under "Assets Subject to Lien," Note 6 to the financial statements of Southern Company and Georgia Power under "DOE Loan Guarantee Borrowings," and Note 6 to the financial statements of Southern Company and Mississippi Power under "Plant Daniel Revenue Bonds" in Item 8 herein for additional information. The traditional electric operating companies own the fee interests in certain of their principal plants as tenants in common. See "Jointly-Owned Facilities" herein for additional information. Properties such as electric transmission and distribution lines, steam heating mains, and gas pipelines are constructed principally on rights-of-way, which are maintained under franchise or are held by easement only. A substantial portion of lands submerged by reservoirs is held under flood right easements. In addition, certain of the renewable generating facilities occupy or use real property that is not owned, primarily through various leases, easements, rights-of-way, permits, or licenses from private landowners or governmental entities.

**Natural Gas**

Southern Company Gas considers its properties to be adequately maintained, substantially in good operating condition, and suitable for their intended purpose. The following provides the location and general character of the materially important properties that are used by the segments of Southern Company Gas. Substantially all of Nicor Gas' properties are subject to the lien of the indenture securing its first mortgage bonds. See Note 6 to the financial statements of Southern Company Gas under "Long-Term Debt – First Mortgage Bonds" in Item 8 herein for additional information.

***Distribution and Transmission Mains*** – Southern Company Gas' distribution systems transport natural gas from its pipeline suppliers to customers in its service areas. These systems consist primarily of distribution and transmission mains, compressor stations, peak shaving/storage plants, service lines, meters, and regulators. At December 31, 2017 , Southern Company Gas' gas distribution operations segment owned approximately 82,000 miles of underground distribution and transmission mains, which are located on easements or rights-of-way that generally provide for perpetual use.

***Storage Assets – Gas Distribution Operations*** – Southern Company Gas owns and operates eight underground natural gas storage facilities in Illinois with a total inventory capacity of approximately 150 Bcf, approximately 135 Bcf of which can be cycled on an annual basis. This system is designed to meet about 50% of the estimated peak-day deliveries and approximately 40% of the normal winter deliveries in Illinois. This level of storage capability provides Nicor Gas with supply flexibility, improves the reliability of deliveries, and helps mitigate the risk associated with seasonal price movements.

Southern Company Gas also has five liquefied natural gas (LNG) plants located in Georgia, New Jersey, and Tennessee with total LNG storage capacity of approximately 7.6 Bcf. In addition, Southern Company Gas owns one propane storage facility in Virginia with storage capacity of approximately 0.3 Bcf. The LNG plants and propane storage facility are used by Southern Company Gas' gas distribution operations segment to supplement natural gas supply during peak usage periods.

***Storage Assets – All Other*** – Southern Company Gas subsidiaries own three high-deliverability natural gas storage and hub facilities that are operated by the gas midstream operations segment. Jefferson Island Storage & Hub, LLC operates a storage facility in Louisiana consisting of two salt dome gas storage caverns. Golden Triangle Storage, Inc. operates a storage facility in Texas consisting of two salt dome caverns. Central Valley Gas Storage, LLC operates a depleted field storage facility in California. In addition, Southern Company Gas has a LNG facility in Alabama that produces LNG for Pivotal LNG, Inc. to support its business of selling LNG as a substitute fuel in various markets.

In August 2017, in connection with an ongoing integrity project into the salt dome gas storage caverns in Louisiana, updated seismic mapping indicated the proximity of one of the caverns to the edge of the salt dome may be less than the required minimum and could result in Southern Company Gas retiring the cavern e arly. See FUTURE EARNINGS POTENTIAL – "Other Matters" and Note 3 to the financial statements of Southern Company and Southern Company Gas in Item 8 herein for additional information.

***Jointly-Owned Properties*** – Southern Company Gas' gas midstream operations segment has a 50% undivided ownership interest in a 115 -mile pipeline facility in northwest Georgia that was placed in service on August 1, 2017 . Southern Company Gas also has an agreement to lease its 50% undivided ownership in the pipeline facility. See Note 4 to the financial statements of Southern Company and Southern Company Gas in Item 8 herein for additional information.

**Item 3. LEGAL PROCEEDINGS**

See Note 3 to the financial statements of each registrant in Item 8 herein for descriptions of legal and administrative proceedings discussed therein.

**Item 4. MINE SAFETY DISCLOSURES**

Not applicable.

**EXECUTIVE OFFICERS OF SOUTHERN COMPANY**

*(Identification of executive officers of Southern Company is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2017 .*

**Thomas A. Fanning**
Chairman, President, and Chief Executive Officer
Age 60
Elected in 2003. Chairman and Chief Executive Officer since December 2010 and President since August 2010.

**Art P. Beattie**
Executive Vice President and Chief Financial Officer
Age 63
Elected in 2010. Executive Vice President and Chief Financial Officer since August 2010.

**W. Paul Bowers**
Executive Vice President
Age 61
Elected in 2001. Executive Vice President since February 2008 and Chief Executive Officer, President, and Director of Georgia Power since January 2011. Chairman of Georgia Power's Board of Directors since May 2014.

**S. W. Connally, Jr.**
Chairman, President, and Chief Executive Officer of Gulf Power
Age 48
Elected in 2012. Elected Chairman in July 2015 and President, Chief Executive Officer, and Director of Gulf Power since July 2012.

**Mark A. Crosswhite**
Executive Vice President
Age 55
Elected in 2010. Executive Vice President since July 2012 and President, Chief Executive Officer, and Director of Alabama Power since March 2014. Chairman of Alabama Power's Board of Directors since May 2014. Previously served as Executive Vice President and Chief Operating Officer of Southern Company from July 2012 through February 2014.

**Andrew W. Evans**
Executive Vice President
Age 51
Elected in July 2016. Executive Vice President since July 2016. President of Southern Company Gas since May 2015 and Chief Executive Officer and Chairman of Southern Company Gas' Board of Directors since January 2016. Previously served as Chief Operating Officer of Southern Company Gas from May 2015 through December 2015 and Executive Vice President and Chief Financial Officer of Southern Company Gas from May 2006 through May 2015.

**Kimberly S. Greene**
Executive Vice President
Age 51
Elected in 2013. Executive Vice President and Chief Operating Officer since March 2014. Director of Southern Company Gas since July 2016. Previously served as President and Chief Executive Officer of SCS from April 2013 to February 2014. Before rejoining Southern Company, Ms. Greene served at Tennessee Valley Authority as Executive Vice President and Chief Generation Officer from 2011 through April 2013.

**James Y. Kerr II**
Executive Vice President and General Counsel
Age 53
Elected in 2014. Also serves as Chief Compliance Officer. Before joining Southern Company, Mr. Kerr was a partner with McGuireWoods LLP and a senior advisor at McGuireWoods Consulting LLC from 2008 through February 2014.

**Stephen E. Kuczynski**
Chairman, President, and Chief Executive Officer of Southern Nuclear
Age 55
Elected in 2011. Chairman, President, and Chief Executive Officer of Southern Nuclear since July 2011.

**Mark S. Lantrip**
Executive Vice President
Age 63
Elected in 2014. Chairman, President, and Chief Executive Officer of SCS since March 2014. Previously served as Treasurer of Southern Company from October 2007 to February 2014 and Executive Vice President of SCS from November 2010 to March 2014.

**Nancy E. Sykes**
Executive Vice President of SCS
Age 49
Elected in 2016. Also serves as Chief Human Resources Officer of SCS. Before joining Southern Company, Ms. Sykes served as vice president and chief human resources officer at United States Steel Corporation from May 2015 to November 2016. Previously served as Vice President, Human Resources Asia-Pacific at Goodyear Tire and Rubber Company from October 2012 until May 2015.

**Anthony L. Wilson**
Chairman, President, and Chief Executive Officer of Mississippi Power
Age 53
Elected in 2015. President of Mississippi Power since October 2015 and Chief Executive Officer and Director since January 2016. Chairman of Mississippi Power's Board of Directors since August 2016. Previously served as Executive Vice President of Mississippi Power from May 2015 to October 2015 and Executive Vice President of Georgia Power from January 2012 to May 2015.

**Christopher C. Womack**
Executive Vice President
Age 59
Elected in 2008. Executive Vice President and President of External Affairs since January 2009.

The officers of Southern Company were elected at the first meeting of the directors following the last annual meeting of stockholders held on May 24, 2017 , for a term of one year or until their successors are elected and have qualified.

**EXECUTIVE OFFICERS OF ALABAMA POWER**

*(Identification of executive officers of Alabama Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2017 .*

**Mark A. Crosswhite**
Chairman, President, and Chief Executive Officer
Age 55
Elected in 2014. President, Chief Executive Officer, and Director since March 1, 2014. Chairman since May 2014. Previously served as Executive Vice President and Chief Operating Officer of Southern Company from July 2012 through February 2014.

**Greg J. Barker**
Executive Vice President
Age 54
Elected in 2016. Executive Vice President for Customer Services since February 2016. Previously served as Senior Vice President of Marketing and Economic Development from April 2012 to February 2016.

**Philip C. Raymond**
Executive Vice President, Chief Financial Officer, and Treasurer
Age 58
Elected in 2010. Executive Vice President, Chief Financial Officer, and Treasurer since August 2010.

**Zeke W. Smith**
Executive Vice President
Age 58
Elected in 2010. Executive Vice President of External Affairs since November 2010.

**James P. Heilbron**
Senior Vice President and Senior Production Officer
Age 46
Elected in 2013. Senior Vice President and Senior Production Officer since March 2013. Previously served as Senior Vice President and Senior Production Officer of Southern Power Company from July 2010 to February 2013.

**R. Scott Moore**
Senior Vice President
Age 50
Elected in 2017. Senior Vice President of Power Delivery since May 2017. Previously served as Vice President of Transmission from August 2012 to May 2017.

The officers of Alabama Power were elected at the meeting of the directors held on April 28, 2017 for a term of one year or until their successors are elected and have qualified, except for Mr. Moore, whose election as Senior Vice President was effective May 20, 2017.

**EXECUTIVE OFFICERS OF MISSISSIPPI POWER**

*(Identification of executive officers of Mississippi Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2017 .*

**Anthony L. Wilson**
Chairman, President, and Chief Executive Officer
Age 53
Elected in 2015. President since October 2015 and Chief Executive Officer and Director since January 2016. Chairman of Mississippi Power's Board since August 2016. Previously served as Executive Vice President from May 2015 to October 2015 and Executive Vice President of Georgia Power from January 2012 to May 2015.

**John W. Atherton**
Vice President
Age 57
Elected in 2004. Vice President of Corporate Services and Community Relations since October 2012.

**A. Nicole Faulk**
Vice President
Age 44
Elected in 2015. Vice President of Customer Services Organization effective April 2015. Previously served as Region Vice President for the West Region of Georgia Power from March 2015 through April 2015 and Region Manager for the Metro West Region of Georgia Power from December 2011 to March 2015.

**Moses H. Feagin**
Vice President, Treasurer, and Chief Financial Officer
Age 53
Elected in 2010. Vice President, Treasurer, and Chief Financial Officer since August 2010.

**R. Allen Reaves, Jr.**
Vice President
Age 58
Elected in 2010. Vice President and Senior Production Officer since August 2010.

**Billy F. Thornton**
Vice President
Age 57
Elected in 2012. Vice President of External Affairs since October 2012.

The officers of Mississippi Power were elected at the meeting of the directors held on May 1, 2017 for a term of one year or until their successors are elected and have qualified.

# PART II

## Item 5. MARKET FOR REGISTRANTS' COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

(a)(1) The common stock of Southern Company is listed and traded on the NYSE. The common stock is also traded on regional exchanges across the U.S. The high and low stock prices as reported on the NYSE for each quarter of the past two years were as follows:

| | High | Low |
|---|---|---|
| **2017** | | |
| First Quarter | $ 51.47 | $ 47.57 |
| Second Quarter | 51.97 | 47.87 |
| Third Quarter | 50.80 | 46.71 |
| Fourth Quarter | 53.51 | 47.92 |
| **2016** | | |
| First Quarter | $ 51.73 | $ 46.00 |
| Second Quarter | 53.64 | 47.62 |
| Third Quarter | 54.64 | 50.00 |
| Fourth Quarter | 52.23 | 46.20 |

There is no market for the other registrants' common stock, all of which is owned by Southern Company.

(a)(2) Number of Southern Company's common stockholders of record at January 31, 2018 : 120,413

Each of the other registrants have one common stockholder, Southern Company.

(a)(3) Dividends on each registrant's common stock are payable at the discretion of their respective board of directors and depend upon earnings, financial condition, and other factors. The dividends on common stock declared by Southern Company, the traditional electric operating companies (other than Mississippi Power), Southern Power Company, and Southern Company Gas to their stockholder(s) for the past two years are set forth below. No dividends were declared by Mississippi Power on its common stock in 2016 or 2017 . Southern Company Gas' dividends are only shown for periods subsequent to the Merger.

| Registrant | Quarter | 2017 | 2016 |
|---|---|---|---|
| | | *(in thousands)* | |
| **Southern Company** | First | $ 555,791 | $ 496,718 |
| | Second | 578,525 | 526,267 |
| | Third | 581,501 | 529,876 |
| | Fourth | 584,015 | 551,110 |
| **Alabama Power** | First | 178,507 | 191,206 |
| | Second | 178,507 | 191,206 |
| | Third | 178,507 | 191,206 |
| | Fourth | 178,507 | 191,206 |
| **Georgia Power** | First | 320,242 | 326,269 |
| | Second | 320,242 | 326,269 |
| | Third | 320,242 | 326,269 |
| | Fourth | 320,242 | 326,269 |
| **Gulf Power** | First | 31,250 | 30,017 |
| | Second | 31,250 | 30,017 |
| | Third | 31,250 | 30,017 |
| | Fourth | 71,250 | 30,017 |
| **Southern Power Company** | First | 79,211 | 68,082 |
| | Second | 79,211 | 68,082 |
| | Third | 79,211 | 68,082 |
| | Fourth | 79,211 | 68,082 |
| **Southern Company Gas** | First | 110,641 | — |
| | Second | 110,641 | — |
| | Third | 110,641 | 62,750 |
| | Fourth | 110,641 | 62,750 |

The dividend paid per share of Southern Company's common stock was 56.00¢ for the first quarter 2017 and 58.00¢ each for the second, third, and fourth quarters of 2017 . In 2016 , Southern Company paid a dividend per share of 54.25¢ for the first quarter and 56.00¢ each for the second, third, and fourth quarters.

The traditional electric operating companies and Southern Power Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital. The authority of the natural gas distribution utilities to pay dividends to Southern Company Gas is subject to regulation. By regulation, Nicor Gas is restricted, to the extent of its retained earnings balance, in the amount it can dividend or loan to affiliates. Additionally, Elizabethtown Gas is restricted by its policy, as established by the New Jersey Board of Public Utilities, to 70% of its quarterly net income it can dividend to Southern Company Gas. Also, as stipulated in the New Jersey Board of Public Utilities' order approving the Merger, Southern Company Gas is prohibited from paying dividends to its parent company, Southern Company, if Southern Company Gas' senior unsecured debt rating falls below investment grade.

(a)(4) Securities authorized for issuance under equity compensation plans.

See Part III, Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

(b) Use of Proceeds

Not applicable.

(c) Issuer Purchases of Equity Securities

None.

**Item 6. SELECTED FINANCIAL DATA**



**Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS**



**Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK**

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of each of the registrants in Item 7 herein and Note 1 of each of the registrant's financial statements under "Financial Instruments" in Item 8 herein. See also Notes 10 and 11 to the financial statements of Southern Company, Alabama Power, and Georgia Power, Notes 9 and 10 to the financial statements of Gulf Power, Mississippi Power, and Southern Company Gas, and Notes 8 and 9 to the financial statements of Southern Power in Item 8 herein.

**Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA**

*INDEX TO 2017 FINANCIAL STATEMENTS*

**Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE**

None.

**Item 9A. CONTROLS AND PROCEDURES**

**Disclosure Controls and Procedures.**

As of the end of the period covered by this Annual Report on Form 10-K, Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and Southern Company Gas conducted separate evaluations under the supervision and with the participation of each company's management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended). Based upon these evaluations, the Chief Executive Officer and the Chief Financial Officer, in each case, concluded that the disclosure controls and procedures are effective.

**Internal Control Over Financial Reporting.**

**(a) Management's Annual Report on Internal Control Over Financial Reporting.**



**(b) Attestation Report of the Registered Public Accounting Firm.**

The report of Deloitte & Touche LLP, Southern Company's independent registered public accounting firm, regarding Southern Company's Internal Control over Financial Reporting is included on page II-9 of this Form 10-K. This report is not applicable to Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and Southern Company Gas as these companies are not accelerated filers or large accelerated filers.

**(c) Changes in internal control over financial reporting.**

There have been no changes in Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's, Southern Power's, or Southern Company Gas' internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended) during the fourth quarter 2017 that have materially affected or are reasonably likely to materially affect Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's, Southern Power's, or Southern Company Gas' internal control over financial reporting.

**Item 9B. OTHER INFORMATION**

None.

# THE SOUTHERN COMPANY
# AND SUBSIDIARY COMPANIES

# FINANCIAL SECTION

**MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING**
**Southern Company and Subsidiary Companies 2017 Annual Report**

The management of The Southern Company (Southern Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of Southern Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Southern Company's internal control over financial reporting was effective as of December 31, 2017 .

Deloitte & Touche LLP, as auditors of Southern Company's financial statements, has issued an attestation report on the effectiveness of Southern Company's internal control over financial reporting as of December 31, 2017 , which is included herein.

/s/ Thomas A. Fanning
Thomas A. Fanning
Chairman, President, and Chief Executive Officer

/s/ Art P. Beattie
Art P. Beattie
Executive Vice President and Chief Financial Officer

February 20, 2018

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the stockholders and the Board of Directors of The Southern Company and Subsidiary Companies

**Opinions on the Financial Statements and Internal Control over Financial Reporting**

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of The Southern Company and Subsidiary Companies (the Company) as of December 31, 2017 and 2016 , the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2017 , and the related notes (collectively referred to as the "financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2017 , based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the financial statements (pages II-64 to II-151 ) referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016 , and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017 , in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017 , based on criteria established in *Internal Control – Integrated Framework (2013)* issued by COSO.

**Basis for Opinions**

The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting (page II-8 ). Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

**Definition and Limitations of Internal Control over Financial Reporting**

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 20, 2018

We have served as the Company's auditor since 2002.

**DEFINITIONS**

| Term | Meaning |
|---|---|
| 2012 MPSC CPCN Order | A detailed order issued by the Mississippi PSC in April 2012 confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing acquisition, construction, and operation of Mississippi Power's Kemper County energy facility |
| 2013 ARP | Alternative Rate Plan approved by the Georgia PSC in 2013 for Georgia Power for the years 2014 through 2016 and subsequently extended through 2019 |
| AFUDC | Allowance for funds used during construction |
| Alabama Power | Alabama Power Company |
| ARO | Asset retirement obligation |
| ASC | Accounting Standards Codification |
| ASU | Accounting Standards Update |
| Atlanta Gas Light | Atlanta Gas Light Company, a wholly-owned subsidiary of Southern Company Gas |
| Atlantic Coast Pipeline | Atlantic Coast Pipeline, LLC, a joint venture to construct and operate a natural gas pipeline in which Southern Company Gas has a 5% ownership interest |
| Bechtel | Bechtel Power Corporation |
| CCR | Coal combustion residuals |
| Clean Air Act | Clean Air Act Amendments of 1990 |
| $CO_2$ | Carbon dioxide |
| COD | Commercial operation date |
| Contractor Settlement Agreement | The December 31, 2015 agreement between Westinghouse and the Vogtle Owners resolving disputes between the Vogtle Owners and the EPC Contractor under the Vogtle 3 and 4 Agreement |
| Cooperative Energy | Electric cooperative in Mississippi |
| CPCN | Certificate of public convenience and necessity |
| CWIP | Construction work in progress |
| Dalton Pipeline | A pipeline facility in Georgia in which Southern Company Gas has a 50% undivided ownership interest |
| DOE | U.S. Department of Energy |
| Eligible Project Costs | Certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the loan guarantee program established under Title XVII of the Energy Policy Act of 2005 |
| EPA | U.S. Environmental Protection Agency |
| EPC Contractor | Westinghouse and its affiliate, WECTEC Global Project Services Inc.; the former engineering, procurement, and construction contractor for Plant Vogtle Units 3 and 4 |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| FFB | Federal Financing Bank |
| GAAP | U.S. generally accepted accounting principles |
| Georgia Power | Georgia Power Company |
| Gulf Power | Gulf Power Company |
| IGCC | Integrated coal gasification combined cycle, the technology originally approved for Mississippi Power's Kemper County energy facility (Plant Ratcliffe) |
| Interim Assessment Agreement | Agreement entered into by the Vogtle Owners and the EPC Contractor to allow construction to continue after the EPC Contractor's bankruptcy filing |
| IRS | Internal Revenue Service |
| ITC | Investment tax credit |
| KWH | Kilowatt-hour |
| LIBOR | London Interbank Offered Rate |

**DEFINITIONS**
(continued)

| Term | Meaning |
|---|---|
| LIFO | Last-in, first-out |
| Loan Guarantee Agreement | Loan guarantee agreement entered into by Georgia Power with the DOE in 2014, under which the proceeds of borrowings may be used to reimburse Georgia Power for Eligible Project Costs incurred in connection with its construction of Plant Vogtle Units 3 and 4 |
| LTSA | Long-term service agreement |
| Merger | The merger, effective July 1, 2016, of a wholly-owned, direct subsidiary of Southern Company with and into Southern Company Gas, with Southern Company Gas continuing as the surviving corporation |
| Mirror CWIP | A regulatory liability used by Mississippi Power to record financing costs associated with construction of the Kemper County energy facility, which were subsequently refunded to customers |
| Mississippi Power | Mississippi Power Company |
| mmBtu | Million British thermal units |
| Moody's | Moody's Investors Service, Inc. |
| MPUS | Mississippi Public Utilities Staff |
| MW | Megawatt |
| natural gas distribution utilities | Southern Company Gas' seven natural gas distribution utilities (Nicor Gas, Atlanta Gas Light, Virginia Natural Gas, Inc., Elizabethtown Gas, Florida City Gas, Chattanooga Gas Company, and Elkton Gas) |
| NCCR | Georgia Power's Nuclear Construction Cost Recovery |
| NDR | Alabama Power's Natural Disaster Reserve |
| New Jersey BPU | New Jersey Board of Public Utilities, the state regulatory agency for Elizabethtown Gas |
| Nicor Gas | Northern Illinois Gas Company, a wholly-owned subsidiary of Southern Company Gas |
| $NO_X$ | Nitrogen oxide |
| NRC | U.S. Nuclear Regulatory Commission |
| OCI | Other comprehensive income |
| PennEast Pipeline | PennEast Pipeline Company, LLC, a joint venture to construct and operate a natural gas pipeline in which Southern Company Gas has a 20% ownership interest |
| PowerSecure | PowerSecure, Inc. |
| power pool | The operating arrangement whereby the integrated generating resources of the traditional electric operating companies and Southern Power (excluding subsidiaries) are subject to joint commitment and dispatch in order to serve their combined load obligations |
| PPA | Power purchase agreements, as well as, for Southern Power, contracts for differences that provide the owner of a renewable facility a certain fixed price for the electricity sold to the grid |
| PSC | Public Service Commission |
| PTC | Production tax credit |
| Rate CNP | Alabama Power's Rate Certificated New Plant |
| Rate CNP Compliance | Alabama Power's Rate Certificated New Plant Compliance |
| Rate CNP PPA | Alabama Power's Rate Certificated New Plant Power Purchase Agreement |
| Rate ECR | Alabama Power's Rate Energy Cost Recovery |
| Rate NDR | Alabama Power's Rate Natural Disaster Reserve |
| Rate RSE | Alabama Power's Rate Stabilization and Equalization plan |
| ROE | Return on equity |
| S&P | S&P Global Ratings, a division of S&P Global Inc. |
| SCS | Southern Company Services, Inc. (the Southern Company system service company) |
| SEC | U.S. Securities and Exchange Commission |
| SEGCO | Southern Electric Generating Company |

**DEFINITIONS**
(continued)

| Term | Meaning |
|---|---|
| $SO_2$ | Sulfur dioxide |
| Southern Company Gas | Southern Company Gas and its subsidiaries |
| Southern Company Gas Capital | Southern Company Gas Capital Corporation, a 100%-owned subsidiary of Southern Company Gas |
| Southern Company system | The Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), SEGCO, Southern Nuclear, SCS, Southern Linc, PowerSecure (as of May 9, 2016), and other subsidiaries |
| Southern Linc | Southern Communications Services, Inc. |
| Southern Nuclear | Southern Nuclear Operating Company, Inc. |
| Southern Power | Southern Power Company and its subsidiaries |
| Tax Reform Legislation | The Tax Cuts and Jobs Act, which was signed into law on December 22, 2017 and became effective on January 1, 2018 |
| Toshiba | Toshiba Corporation, parent company of Westinghouse |
| Toshiba Guarantee | Certain payment obligations of the EPC Contractor guaranteed by Toshiba |
| traditional electric operating companies | Alabama Power, Georgia Power, Gulf Power, and Mississippi Power |
| VCM | Vogtle Construction Monitoring |
| Vogtle 3 and 4 Agreement | Agreement entered into with the EPC Contractor in 2008 by Georgia Power, acting for itself and as agent for the Vogtle Owners, pursuant to which the EPC Contractor agreed to design, engineer, procure, construct, and test Plant Vogtle Units 3 and 4 |
| Vogtle Owners | Georgia Power, Oglethorpe Power Corporation, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light, and Sinking Fund Commissioners |
| Vogtle Services Agreement | The June 9, 2017 services agreement between the Vogtle Owners and the EPC Contractor, as amended and restated on July 20, 2017, for the EPC Contractor to transition construction management of Plant Vogtle Units 3 and 4 to Southern Nuclear and to provide ongoing design, engineering, and procurement services to Southern Nuclear |
| Westinghouse | Westinghouse Electric Company LLC |

**MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS**
**Southern Company and Subsidiary Companies 2017 Annual Report**

## OVERVIEW

### Business Activities

The Southern Company (Southern Company or the Company) is a holding company that owns all of the common stock of the traditional electric operating companies and the parent entities of Southern Power and Southern Company Gas and owns other direct and indirect subsidiaries. The primary businesses of the Southern Company system are electricity sales by the traditional electric operating companies and Southern Power and the distribution of natural gas by Southern Company Gas. The four traditional electric operating companies are vertically integrated utilities providing electric service in four Southeastern states. Southern Power develops, constructs, acquires, owns, and manages power generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Company Gas distributes natural gas through natural gas distribution utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations. See FUTURE EARNINGS POTENTIAL – "General" herein for information regarding agreements entered into by a wholly-owned subsidiary of Southern Company Gas to sell two of its natural gas distribution utilities.

Many factors affect the opportunities, challenges, and risks of the Southern Company system's electricity and natural gas businesses. These factors include the ability to maintain constructive regulatory environments, to maintain and grow sales and customers, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, stringent environmental standards, reliability, fuel, restoration following major storms, and capital expenditures, including constructing new electric generating plants, expanding the electric transmission and distribution systems, and updating and expanding the natural gas distribution systems.

The traditional electric operating companies and natural gas distribution utilities have various regulatory mechanisms that operate to address cost recovery. Effectively operating pursuant to these regulatory mechanisms and appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Southern Company system for the foreseeable future. See Note 3 to the financial statements under "Regulatory Matters" for additional information.

Another major factor affecting the Southern Company system's businesses is the profitability of the competitive market-based wholesale generating business. Southern Power's strategy is to create value through various transactions including acquisitions and sales of assets, development and construction of new generating facilities, and entry into PPAs primarily with investor-owned utilities, independent power producers, municipalities, electric cooperatives, and other load-serving entities, as well as commercial and industrial customers. In general, Southern Power has committed to the construction or acquisition of new generating capacity only after entering into or assuming long-term PPAs for the new facilities. Southern Power is also currently pursuing the sale of a portion of equity interests in its solar assets. See FUTURE EARNINGS POTENTIAL – "General" herein for additional information.

Southern Company's other business activities include providing energy technologies and services to electric utilities and large industrial, commercial, institutional, and municipal customers. Customer solutions include distributed generation systems, utility infrastructure solutions, and energy efficiency products and services. Other business activities also include investments in telecommunications, leveraged lease projects, and gas storage facilities. Management continues to evaluate the contribution of each of these activities to total shareholder return and may pursue acquisitions, dispositions, and other strategic ventures or investments accordingly.

In striving to achieve attractive risk-adjusted returns while providing cost-effective energy to more than nine million electric and gas utility customers, the Southern Company system continues to focus on several key performance indicators. These indicators include, but are not limited to, customer satisfaction, plant availability, electric and natural gas system reliability, execution of major construction projects, and earnings per share (EPS). Southern Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the results of the Southern Company system.

See RESULTS OF OPERATIONS herein for information on the Company's financial performance.

### Kemper County Energy Facility Status

The Kemper County energy facility was approved by the Mississippi PSC as an IGCC facility in the 2010 CPCN proceedings, subject to a construction cost cap of $2.88 billion, net of $245 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (Initial DOE Grants) and excluding the cost of the lignite mine and equipment, the cost of the $CO_2$ pipeline facilities, AFUDC, and certain general exceptions (Cost Cap Exceptions). The combined cycle and associated common facilities portions of the Kemper County energy facility were placed in service in August 2014. In December 2015, the Mississippi PSC issued an order (In-Service Asset Rate Order), authorizing rates that provided for the recovery of approximately $126 million annually related to the assets previously placed in service.

On June 21, 2017, the Mississippi PSC stated its intent to issue an order (which occurred on July 6, 2017) directing Mississippi Power to pursue a settlement under which the Kemper County energy facility would be operated as a natural gas plant, rather than an IGCC plant, and address all issues associated with the Kemper County energy facility (Kemper Settlement Order). The Kemper Settlement Order established a new docket for the purposes of pursuing a global settlement of the related costs (Kemper Settlement Docket).

On June 28, 2017, Mississippi Power notified the Mississippi PSC that it would begin a process to suspend operations and start-up activities on the gasifier portion of the Kemper County energy facility, given the uncertainty as to its future. At the time of project suspension, the total cost estimate for the Kemper County energy facility was approximately $7.38 billion, including approximately $5.95 billion of costs subject to the construction cost cap, and was net of the $137 million in additional grants from the DOE received on April 8, 2016 (Additional DOE Grants). In the aggregate, Mississippi Power had incurred charges of $3.07 billion ($1.89 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through May 31, 2017. Given the Mississippi PSC's stated intent regarding no further rate increase for the Kemper County energy facility and the subsequent suspension, cost recovery of the gasifier portions became no longer probable; therefore, Mississippi Power recorded an additional charge to income in June 2017 of $2.8 billion ($2.0 billion after tax), which included estimated costs associated with the gasifier portions of the plant and lignite mine.

On February 6, 2018, the Mississippi PSC voted to approve a settlement agreement related to cost recovery for the Kemper County energy facility among Mississippi Power, the MPUS, and certain intervenors (Kemper Settlement Agreement). The Kemper Settlement Agreement provides for an annual revenue requirement of approximately $99.3 million for costs related to the Kemper County energy facility, which includes the impact of Tax Reform Legislation. The revenue requirement is based on (i) a fixed ROE for 2018 of 8.6%, excluding any performance adjustment, (ii) a ROE for 2019 calculated in accordance with Mississippi Power's Performance Evaluation Plan (PEP), excluding the performance adjustment, (iii) for future years, a performance-based ROE calculated pursuant to PEP, and (iv) amortization periods for the related regulatory assets and liabilities of eight years and six years, respectively. The revenue requirement also reflects a disallowance related to a portion of Mississippi Power's investment in the Kemper County energy facility requested for inclusion in rate base, which was recorded in the fourth quarter 2017 as an additional charge to income of approximately $78 million ($85 million net of accumulated depreciation of $7 million) pre-tax ($48 million after tax).

Under the Kemper Settlement Agreement, retail customer rates will reflect a reduction of approximately $26.8 million annually and include no recovery for costs associated with the gasifier portion of the Kemper County energy facility in 2018 or at any future date. On February 12, 2018, Mississippi Power made the required compliance filing with the Mississippi PSC. The Kemper Settlement Agreement also requires (i) the CPCN for the Kemper County energy facility to be modified to limit it to natural gas combined cycle operation and (ii) Mississippi Power to file a reserve margin plan with the Mississippi PSC by August 2018.

During the third and fourth quarters of 2017, Mississippi Power recorded charges to income of $242 million ($206 million after tax), including $164 million for ongoing project costs, estimated mine and gasifier-related costs, and certain termination costs during the suspension period prior to conclusion of the Kemper Settlement Docket, as well as the charge associated with the Kemper Settlement Agreement. Additional pre-tax cancellation costs, including mine and plant closure and contract termination costs, currently estimated at approximately $50 million to $100 million (excluding salvage), are expected to be incurred in 2018. Mississippi Power has begun efforts to dispose of or abandon the mine and gasifier-related assets.

Total pre-tax charges to income related to the Kemper County energy facility were $3.4 billion ($2.4 billion after tax) for the year ended December 31, 2017. In the aggregate, since the Kemper County energy facility project started, Mississippi Power has incurred charges of $6.2 billion ($4.1 billion after tax) through December 31, 2017.

As a result of the Mississippi PSC order on February 6, 2018, rate recovery for the Kemper County energy facility is resolved, subject to any future legal challenges.

See Note 3 to the financial statements under " Kemper County Energy Facility " for additional information.

**Plant Vogtle Units 3 and 4 Status**

In 2009, the Georgia PSC certified construction of Plant Vogtle Units 3 and 4. In 2012, the NRC issued the related combined construction and operating licenses, which allowed full construction of the two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities to begin. Until March 2017, construction on Plant Vogtle Units

3 and 4 continued under the Vogtle 3 and 4 Agreement, which was a substantially fixed price agreement. On March 29, 2017, the EPC Contractor filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code.

In connection with the EPC Contractor's bankruptcy filing, Georgia Power, acting for itself and as agent for the Vogtle Owners, entered into the Interim Assessment Agreement with the EPC Contractor to allow construction to continue. The Interim Assessment Agreement expired on July 27, 2017 when the Vogtle Services Agreement became effective. In August 2017, following completion of comprehensive cost to complete and cancellation cost assessments, Georgia Power filed its seventeenth VCM report with the Georgia PSC, which included a recommendation to continue construction of Plant Vogtle Units 3 and 4, with Southern Nuclear serving as project manager and Bechtel serving as the primary construction contractor. On December 21, 2017, the Georgia PSC approved Georgia Power's recommendation to continue construction.

Georgia Power expects Plant Vogtle Units 3 and 4 to be placed in service by November 2021 and November 2022, respectively. Georgia Power's revised capital cost forecast for its 45.7% proportionate share of Plant Vogtle Units 3 and 4 is $8.8 billion ( $7.3 billion after reflecting the impact of payments received under a settlement agreement regarding the Toshiba Guarantee (Guarantee Settlement Agreement) and certain refunds to customers ordered by the Georgia PSC (Customer Refunds)). Georgia Power's CWIP balance for Plant Vogtle Units 3 and 4 was $3.3 billion at December 31, 2017 , which is net of the Guarantee Settlement Agreement payments less the Customer Refunds. Georgia Power estimates that its financing costs for construction of Plant Vogtle Units 3 and 4 will total approximately $3.1 billion , of which $1.6 billion had been incurred through December 31, 2017 .

See Note 3 to the financial statements under " Nuclear Construction " for additional information.

**Earnings**

Consolidated net income attributable to Southern Company was $842 million in 2017 , a decrease of $1.6 billion , or 65.6% **,** from the prior year. The decrease was primarily due to pre-tax charges of $3.4 billion ($2.4 billion after tax) related to the Kemper IGCC at Mississippi Power. Also contributing to the change were increases of $240 million in net income from Southern Company Gas (excluding the impact of $111 million in additional expense related to the Tax Reform Legislation) reflecting the 12-month period in 2017 compared to the six-month period following the Merger closing on July 1, 2016, $264 million related to net tax benefits from the Tax Reform Legislation, higher retail electric revenues resulting from increases in base rates partially offset by milder weather and lower customer usage, and increases in renewable energy sales at Southern Power. These increases were partially offset by higher interest and depreciation and amortization.

Consolidated net income attributable to Southern Company was $2.4 billion in 2016 , an increase of $81 million , or 3.4% , from the prior year. Consolidated net income increased by $114 million as a result of earnings from Southern Company Gas, which was acquired on July 1, 2016. Also contributing to the increase were higher retail electric revenues resulting from non-fuel retail rate increases and warmer weather, primarily in the third quarter 2016, as well as the 2015 correction of a Georgia Power billing error, partially offset by accruals in 2016 for expected refunds at Alabama Power and Georgia Power. Additionally, the increase was due to increases in income tax benefits and renewable energy sales at Southern Power. These increases were partially offset by higher interest expense, non-fuel operations and maintenance expenses, depreciation and amortization, lower wholesale capacity revenues, and higher estimated losses associated with the Kemper IGCC.

See Note 12 to the financial statements under " Southern Company – Merger with Southern Company Gas " for additional information regarding the Merger.

Basic EPS was $0.84 in 2017 , $2.57 in 2016 , and $2.60 in 2015 . Diluted EPS, which factors in additional shares related to stock-based compensation, was $0.84 in 2017 , $2.55 in 2016 , and $2.59 in 2015 . EPS for 2017 was negatively impacted by $0.04 per share as a result of an increase in the average shares outstanding. See FINANCIAL CONDITION AND LIQUIDITY – " Financing Activities " herein for additional information.

**Dividends**

Southern Company has paid dividends on its common stock since 1948. Dividends paid per share of common stock were $2.30 in 2017 , $2.22 in 2016 , and $2.15 in 2015 . In January 2018 , Southern Company declared a quarterly dividend of 58 cents per share. This is the 281st consecutive quarter that Southern Company has paid a dividend equal to or higher than the previous quarter. For 2017 , the dividend payout ratio was 273% compared to 86% for 2016. The increase was due to a significant reduction in earnings resulting from charges related to the Kemper IGCC. See "Earnings" and RESULTS OF OPERATIONS – "Electricity Business – Estimated Loss on Kemper IGCC " herein and Note 3 to the financial statements under " Kemper County Energy Facility " for additional information.

## RESULTS OF OPERATIONS

Discussion of the results of operations is divided into three parts – the Southern Company system's primary business of electricity sales, its gas business, and its other business activities.

| | Amount | | |
|---|---|---|---|
| | **2017** | 2016 | 2015 |
| | | *(in millions)* | |
| Electricity business | **$ 878** | $ 2,571 | $ 2,401 |
| Gas business | **243** | 114 | — |
| Other business activities | **(279)** | (237) | (34) |
| Net Income | **$ 842** | $ 2,448 | $ 2,367 |

### Electricity Business

Southern Company's electric utilities generate and sell electricity to retail and wholesale customers.

A condensed statement of income for the electricity business follows:

| | Amount | Increase (Decrease) from Prior Year | |
|---|---|---|---|
| | **2017** | **2017** | 2016 |
| | | *(in millions)* | |
| Electric operating revenues | **$ 18,540** | **$ 599** | $ 499 |
| Fuel | **4,400** | **39** | (389) |
| Purchased power | **863** | **113** | 105 |
| Cost of other sales | **69** | **11** | 58 |
| Other operations and maintenance | **4,340** | **(183)** | 231 |
| Depreciation and amortization | **2,457** | **224** | 213 |
| Taxes other than income taxes | **1,063** | **24** | 44 |
| Estimated loss on Kemper IGCC | **3,362** | **2,934** | 63 |
| Total electric operating expenses | **16,554** | **3,162** | 325 |
| Operating income | **1,986** | **(2,563)** | 174 |
| Allowance for equity funds used during construction | **152** | **(48)** | (26) |
| Interest expense, net of amounts capitalized | **1,011** | **80** | 157 |
| Other income (expense), net | **(83)** | **(8)** | (43) |
| Income taxes | **82** | **(1,009)** | (235) |
| Net income | **962** | **(1,690)** | 183 |
| Less: | | | |
| Dividends on preferred and preference stock of subsidiaries | **38** | **(7)** | (9) |
| Net income attributable to noncontrolling interests | **46** | **10** | 22 |
| Net Income Attributable to Southern Company | **$ 878** | **$ (1,693)** | $ 170 |

***Electric Operating Revenues***

Electric operating revenues for 2017 were $18.5 billion , reflecting a $599 million increase from 2016. Details of electric operating revenues were as follows:

| | Amount | |
|---|---|---|
| | **2017** | 2016 |
| | *(in millions)* | |
| Retail electric — prior year | $ **15,234** | $ 14,987 |
| Estimated change resulting from — | | |
| Rates and pricing | **508** | 427 |
| Sales decline | **(71)** | (35) |
| Weather | **(281)** | 153 |
| Fuel and other cost recovery | **(60)** | (298) |
| Retail electric — current year | **15,330** | 15,234 |
| Wholesale electric revenues | **2,426** | 1,926 |
| Other electric revenues | **681** | 698 |
| Other revenues | **103** | 83 |
| Electric operating revenues | $ **18,540** | $ 17,941 |
| Percent change | **3.3%** | 2.9% |

Retail electric revenues increased $96 million , or 0.6% , in 2017 as compared to the prior year. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing in 2017 was primarily due to a Rate RSE increase at Alabama Power effective in January 2017, the recovery of Plant Vogtle Units 3 and 4 construction financing costs under the NCCR tariff at Georgia Power, and an increase in retail base rates effective July 2017 at Gulf Power. See Note 3 to the financial statements under " Regulatory Matters – Gulf Power – Retail Base Rate Cases " for additional information.

Retail electric revenues increased $247 million , or 1.6% , in 2016 as compared to the prior year. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing in 2016 was primarily due to increases in base tariffs at Georgia Power under the 2013 ARP and the NCCR tariff and increased revenues at Alabama Power under Rate CNP Compliance, all effective January 1, 2016. Also contributing to the increase in rates and pricing for 2016 was the 2015 correction of an error affecting billings since 2013 to a small number of large commercial and industrial customers under a rate plan allowing for variable demand-driven pricing at Georgia Power and the implementation of rates at Mississippi Power for certain Kemper County energy facility in-service assets, effective September 2015. These increases were partially offset by accruals in 2016 for expected refunds at Alabama Power and Georgia Power. See Note 3 to the financial statements under " Kemper County Energy Facility – Rate Recovery " for additional information.

See Note 3 to the financial statements under " Regulatory Matters – Alabama Power – Rate RSE " and " – Rate CNP Compliance " and " Nuclear Construction " and Note 1 to the financial statements under "General" for additional information. Also see "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales decline and weather.

Electric rates for the traditional electric operating companies include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the energy component of PPA costs, and do not affect net income. The traditional electric operating companies each have one or more regulatory mechanisms to recover other costs such as environmental and other compliance costs, storm damage, new plants, and PPA capacity costs.

Wholesale electric revenues consist of PPAs primarily with investor-owned utilities and electric cooperatives and short-term opportunity sales. Wholesale electric revenues from PPAs (other than solar and wind PPAs) have both capacity and energy components. Capacity revenues generally represent the greatest contribution to net income and are designed to provide recovery of fixed costs plus a return on investment. Energy revenues will vary depending on fuel prices, the market prices of wholesale energy compared to the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. Energy sales from solar and wind PPAs do not have a capacity charge and customers either purchase the energy output of a dedicated renewable facility through an energy charge or through a fixed price related to the energy. As a result, the Company's ability to recover fixed and variable operations and maintenance expenses is dependent upon the level of energy generated from these facilities, which can be impacted by weather conditions, equipment performance, transmission constraints, and other factors. Wholesale electric revenues at Mississippi Power include FERC-regulated municipal and rural association sales as well as market-based sales. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Southern Company system's variable cost to produce the energy.

Wholesale electric revenues from power sales were as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| Capacity and other | **$ 838** | $ 771 | $ 875 |
| Energy | **1,588** | 1,155 | 923 |
| Total | **$ 2,426** | $ 1,926 | $ 1,798 |

In 2017, wholesale revenues increased $500 million , or 26.0% , as compared to the prior year due to a $433 million increase in energy revenues and a $67 million increase in capacity revenues, primarily at Southern Power. The increase in energy revenues was primarily due to increases in renewable energy sales arising from new solar and wind facilities and non-PPA revenues from short-term sales. The increase in capacity revenues was primarily due to a PPA related to new natural gas facilities and additional customer capacity requirements.

In 2016, wholesale revenues increased $128 million , or 7.1% , as compared to the prior year due to a $232 million increase in energy revenues, partially offset by a $104 million decrease in capacity revenues. The increase in energy revenues was primarily due to increases in short-term sales and renewable energy sales at Southern Power, partially offset by lower fuel prices. The decrease in capacity revenues was primarily due to the expiration of wholesale contracts at Georgia Power and Gulf Power, the elimination in consolidation of a Southern Power PPA that was remarketed from a third party to Georgia Power in January 2016, and unit retirements at Georgia Power, partially offset by an increase due to a new wholesale contract at Alabama Power in the first quarter 2016.

*Other Electric Revenues*

Other electric revenues decreased $17 million , or 2.4% , and increased $41 million , or 6.2% , in 2017 and 2016, respectively, as compared to the prior years. The 2017 decrease was primarily due to a $15 million decrease in open access transmission tariff revenues, primarily as a result of the expiration of long-term transmission services contracts at Georgia Power. The 2016 increase was primarily due to a $14 million increase in customer temporary facilities services revenues and a $12 million increase in outdoor lighting revenues at Georgia Power, primarily attributable to LED conversions.

*Energy Sales*

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2017 and the percent change from the prior year were as follows:

| | **Total KWHs** | **Total KWH Percent Change** | | **Weather-Adjusted Percent Change** | |
|---|---|---|---|---|---|
| | **2017** | **2017** | 2016 | **2017** | 2016 |
| | *(in billions)* | | | | |
| Residential | **50.5** | **(5.3)%** | 2.3 % | **(0.3)%** | 0.2 % |
| Commercial | **52.3** | **(2.6)** | 0.4 | **(0.9)** | (1.0) |
| Industrial | **52.8** | **—** | (2.1) | **—** | (2.2) |
| Other | **0.9** | **(4.0)** | (1.7) | **(3.9)** | (1.7) |
| Total retail | **156.5** | **(2.6)** | 0.2 | **(0.4)%** | (1.0)% |
| Wholesale | **49.0** | **32.4** | 21.4 | | |
| Total energy sales | **205.5** | **3.9 %** | 3.6 % | | |

Changes in retail energy sales are generally the result of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales decreased 4.2 billion KWHs in 2017 as compared to the prior year. This decrease was primarily due to milder weather and decreased customer usage, partially offset by customer growth. Weather-adjusted residential KWH sales decreased primarily due to decreased customer usage resulting from an increase in penetration of energy-efficient residential appliances and an increase in multi-family housing, partially offset by customer growth. Weather-adjusted commercial KWH sales decreased primarily due to decreased customer usage resulting from customer initiatives in energy savings and an ongoing migration to the electronic commerce business model, partially offset by customer growth. Industrial KWH energy sales were flat primarily due to decreased sales in the paper, stone, clay, and glass, transportation, and chemicals sectors, offset by increased sales in the primary metals and textile sectors. Additionally, Hurricane Irma negatively impacted customer usage for all customer classes.

Retail energy sales increased 261 million KWHs in 2016 as compared to the prior year. This increase was primarily due to warmer weather in the third quarter 2016 as compared to the corresponding period in 2015 and customer growth, partially offset by decreased customer usage. The decrease in industrial KWH energy sales was primarily due to decreased sales in the primary metals, chemicals, paper, pipeline, and stone, clay, and glass sectors. A strong dollar, low oil prices, and weak global economic conditions constrained growth in the industrial sector in 2016. Weather-adjusted commercial KWH sales decreased primarily due to decreased customer usage resulting from an increase in electronic commerce transactions and energy saving initiatives, partially offset by customer growth. Weather-adjusted residential KWH sales increased primarily due to customer growth, partially offset by decreased customer usage primarily resulting from an increase in multi-family housing and efficiency improvements in residential appliances and lighting. Household income, one of the primary drivers of residential customer usage, had modest growth in 2016.

See "Electric Operating Revenues" above for a discussion of significant changes in wholesale revenues related to changes in price and KWH sales.

*Other Revenues*

Other revenues increased $20 million , or 24.1% , in 2017 as compared to the prior year. The 2017 increase was primarily due to additional third party infrastructure services.

Other revenues increased $83 million in 2016 as compared to the prior year. The 2016 increase was primarily due to revenues from certain non-regulated sales of products and services by the traditional electric operating companies that were reclassified as other revenues for consistency of presentation on a consolidated basis following the PowerSecure acquisition. In prior periods, these revenues were included in other income (expense), net.

***Fuel and Purchased Power Expenses***

Fuel costs constitute one of the largest expenses for the electric utilities. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the electric utilities purchase a portion of their electricity needs from the wholesale market.

Details of the Southern Company system's generation and purchased power were as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| Total generation *(in billions of KWHs)* | **194** | 188 | 187 |
| Total purchased power *(in billions of KWHs)* | **20** | 19 | 13 |
| Sources of generation *(percent)* — | | | |
| Gas | **46** | 46 | 46 |
| Coal | **30** | 33 | 34 |
| Nuclear | **16** | 16 | 16 |
| Hydro | **2** | 2 | 3 |
| Other | **6** | 3 | 1 |
| Cost of fuel, generated *(in cents per net KWH)* — | | | |
| Gas | **2.79** | 2.48 | 2.60 |
| Coal | **2.81** | 3.04 | 3.55 |
| Nuclear | **0.79** | 0.81 | 0.79 |
| Average cost of fuel, generated *(in cents per net KWH)* | **2.44** | 2.40 | 2.64 |
| Average cost of purchased power *(in cents per net KWH)* (*) | **5.19** | 4.81 | 6.11 |

(*) Average cost of purchased power includes fuel purchased by the Southern Company system for tolling agreements where power is generated by the provider.

In 2017, total fuel and purchased power expenses were $5.3 billion , an increase of $152 million , or 3.0% , as compared to the prior year. The increase was primarily the result of a $196 million increase in the average cost of fuel and purchased power primarily due to higher natural gas prices, partially offset by a $44 million net decrease in the volume of KWHs generated and purchased.

In 2016, total fuel and purchased power expenses were $5.1 billion , a decrease of $284 million , or 5.3% , as compared to the prior year. The decrease was primarily the result of a $650 million decrease in the average cost of fuel and purchased power primarily due to lower coal and natural gas prices, partially offset by a $366 million increase in the volume of KWHs generated and purchased.

Fuel and purchased power energy transactions at the traditional electric operating companies are generally offset by fuel revenues and do not have a significant impact on net income. See FUTURE EARNINGS POTENTIAL – " Regulatory Matters – Fuel Cost Recovery " herein for additional information. Fuel expenses incurred under Southern Power's PPAs are generally the responsibility of the counterparties and do not significantly impact net income.

*Fuel*

In 2017, fuel expense was $4.4 billion , an increase of $39 million , or 0.9% **,** as compared to the prior year. The increase was primarily due to a 12.5% increase in the average cost of natural gas per KWH generated and a 2.8% increase in the volume of KWHs generated by natural gas, partially offset by a 7.9% decrease in the volume of KWHs generated by coal and a 7.6% decrease in the average cost of coal per KWH generated.

In 2016, fuel expense was $4.4 billion , a decrease of $389 million , or 8.2% , as compared to the prior year. The decrease was primarily due to a 14.4% decrease in the average cost of coal per KWH generated, a 4.6% decrease in the average cost of natural gas per KWH generated, and a 2.7% decrease in the volume of KWHs generated by coal, partially offset by a 3.5% increase in the volume of KWHs generated by natural gas.

*Purchased Power*

In 2017, purchased power expense was $863 million , an increase of $113 million , or 15.1% , as compared to the prior year. The increase was primarily due to a 7.9% increase in the average cost per KWH purchased, primarily as a result of higher natural gas prices, and a 5.0% increase in the volume of KWHs purchased.

In 2016, purchased power expense was $750 million , an increase of $105 million , or 16.3% , as compared to the prior year. The increase was primarily due to a 45.6% increase in the volume of KWHs purchased, partially offset by a 21.3% decrease in the average cost per KWH purchased primarily as a result of lower natural gas prices.

Energy purchases will vary depending on demand for energy within the Southern Company system's electric service territory, the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, and the availability of the Southern Company system's generation.

***Cost of Other Sales***

Cost of other sales were $69 million and $58 million in 2017 and 2016, respectively. These costs were related to certain non-regulated sales of products and services by the traditional electric operating companies that were reclassified as cost of other sales for consistency of presentation on a consolidated basis following the PowerSecure acquisition. In prior periods, these costs were included in other income (expense), net.

***Other Operations and Maintenance Expenses***

Other operations and maintenance expenses decreased $183 million , or 4.0% , in 2017 as compared to the prior year. The decrease was primarily due to cost containment and modernization activities implemented at Georgia Power that contributed to decreases of $85 million in generation maintenance costs, $49 million in other employee compensation and benefits, $46 million in transmission and distribution overhead line maintenance, and $22 million in customer accounts, service, and sales costs. Other factors include a $40 million increase in gains from sales of assets at Georgia Power and a $34 million decrease in scheduled outage and maintenance costs at generation facilities. These decreases were partially offset by a $56 million increase associated with new facilities at Southern Power, a $37 million increase in transmission and distribution costs primarily due to vegetation management at Alabama Power, and $32.5 million resulting from the write-down of Gulf Power's ownership of Plant Scherer Unit 3 in accordance with a rate case settlement agreement approved by the Florida PSC on April 4, 2017 (2017 Rate Case Settlement Agreement).

Other operations and maintenance expenses increased $231 million , or 5.4% , in 2016 as compared to the prior year. The increase was primarily related to a $76 million increase in transmission and distribution expenses primarily related to overhead line maintenance, a $37 million decrease in gains from sales of assets at Georgia Power, a $36 million charge in connection with cost containment activities at Georgia Power, and a $35 million increase at Southern Power associated with new solar and wind facilities placed in service in 2015 and 2016. Additionally, the increase was due to a $19 million increase in generation expenses primarily related to environmental costs, a $19 million increase in business development and support expenses at Southern Power, and an $11 million increase in scheduled outage and maintenance costs at generation facilities, partially offset by a $41 million net decrease in employee compensation and benefits, including pension costs.

Production expenses and transmission and distribution expenses fluctuate from year to year due to variations in outage and maintenance schedules and normal changes in the cost of labor and materials.

***Depreciation and Amortization***

Depreciation and amortization increased $224 million , or 10.0% , in 2017 as compared to the prior year. The increase reflects $203 million related to additional plant in service at the traditional electric operating companies and Southern Power and a $13 million increase in amortization related to environmental compliance at Mississippi Power. The increase was partially offset by a $34 million increase in the reductions in depreciation authorized in Gulf Power's 2013 rate case settlement approved by the Florida PSC as compared to the corresponding period in 2016.

Depreciation and amortization increased $213 million , or 10.5% , in 2016 as compared to the prior year primarily due to additional plant in service at the traditional electric operating companies and Southern Power.

See Note 1 to the financial statements under " Regulatory Assets and Liabilities " and " Depreciation and Amortization " for additional information.

***Taxes Other Than Income Taxes***

Taxes other than income taxes increased $24 million , or 2.3% , in 2017 as compared to the prior year primarily due to an increase in property taxes due to new facilities at Southern Power.

Taxes other than income taxes increased $44 million , or 4.4% , in 2016 as compared to the prior year primarily due to an increase in property taxes due to higher assessed value of property at the traditional electric operating companies, increases in state and municipal utility license tax bases at Alabama Power, an increase in payroll taxes at Georgia Power, and an increase in franchise taxes at Mississippi Power.

***Estimated Loss on Kemper IGCC***

In 2017, 2016, and 2015, estimated probable losses on the Kemper IGCC of $3.4 billion , $428 million , and $365 million , respectively, were recorded at Southern Company. On June 28, 2017, Mississippi Power suspended the gasifier portion of the project and recorded a charge to earnings for the remaining $2.8 billion book value of the gasifier portion of the project. Prior to the suspension, Mississippi Power recorded losses for revisions of estimated costs expected to be incurred on construction of the Kemper IGCC in excess of the $2.88 billion cost cap established by the Mississippi PSC, net of $245 million of the Initial DOE Grants and excluding the Cost Cap Exceptions.

See Note 3 to the financial statements under " Kemper County Energy Facility " for additional information.

***Allowance for Equity Funds Used During Construction***

AFUDC equity decreased $48 million , or 24.0% , in 2017 as compared to the prior year primarily due to Mississippi Power's suspension of the Kemper IGCC project in June 2017.

AFUDC equity decreased $26 million , or 11.5% , in 2016 as compared to the prior year primarily due to environmental and generation projects being placed in service at Alabama Power and Gulf Power, partially offset by a higher AFUDC rate and an increase in Kemper County energy facility CWIP subject to AFUDC at Mississippi Power prior to the suspension of the gasifier portion of the project.

See Note 3 to the financial statements under " Kemper County Energy Facility " for additional information.

***Interest Expense, Net of Amounts Capitalized***

Interest expense, net of amounts capitalized increased $80 million , or 8.6% , in 2017 as compared to the prior year primarily due to an increase in average outstanding long-term debt, primarily at Southern Power and Georgia Power, and a $37 million decrease in interest capitalized, primarily at Southern Power and Mississippi Power, partially offset by a net reduction of $36 million following Mississippi Power's settlement with the IRS related to research and experimental deductions. See Note 5 to the financial statements under " Unrecognized Tax Benefits " for additional information.

Interest expense, net of amounts capitalized increased $157 million , or 20.3% , in 2016 as compared to the prior year primarily due to an increase in interest expense at Southern Power related to additional debt issued primarily to fund its growth strategy and continuous construction program, increases in both the average outstanding long-term debt balance and the average interest rate at the traditional electric operating companies, and the May 2015 termination of an asset purchase agreement between Mississippi Power and Cooperative Energy and the resulting reversal of accrued interest on related deposits.

See Note 6 to the financial statements for additional information.

***Other Income (Expense), Net***

Other income (expense), net decreased $8 million , or 10.7% , in 2017 as compared to the prior year primarily due to increases in charitable donations. The change also includes an increase of $159 million in currency losses arising from a translation of euro-denominated fixed-rate notes into U.S. dollars, fully offset by an equal change in gains on the foreign currency hedges that were reclassified from accumulated OCI into earnings at Southern Power.

Other income (expense), net decreased $43 million , or 134.4% , in 2016 as compared to the prior year primarily due to the reclassification of revenues and costs associated with certain non-regulated sales of products and services by the traditional electric operating companies to other revenues and cost of other sales for consistency of presentation on a consolidated basis following the PowerSecure acquisition. The net amounts reclassified were $25 million. Also contributing to the decrease was an $8 million decrease in customer contributions in aid of construction and a $6 million decrease in wholesale operating fee revenue at Georgia Power.

***Income Taxes***

Income taxes decreased $1.0 billion , or 92.5% , in 2017 as compared to the prior year primarily due to $809 million in tax benefits related to estimated losses on the Kemper IGCC at Mississippi Power and $346 million in net tax benefits resulting from the Tax Reform Legislation.

Income taxes decreased $235 million , or 17.7% , in 2016 as compared to the prior year primarily due to increased federal income tax benefits related to ITCs for solar plants placed in service and PTCs from wind generation at Southern Power in 2016.

See Note 5 to the financial statements for additional information.

**Gas Business**

Southern Company Gas distributes natural gas through utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations.

On July 1, 2016, Southern Company Gas became a wholly-owned, direct subsidiary of Southern Company. Prior to the completion of the Merger, Southern Company and Southern Company Gas operated as separate companies. The condensed statements of income herein includes Southern Company Gas' results of operations since July 1, 2016. See Note 12 to the financial statements under " Southern Company – Merger with Southern Company Gas " for additional information regarding the Merger, including certain pro forma results of operations.

A condensed statement of income for the gas business follows:

| | Amount | Increase (Decrease) from Prior Year |
|---|---|---|
| | 2017 | 2017 |
| | *(in millions)* | |
| Operating revenues | $ 3,920 | $ 2,268 |
| Cost of natural gas | 1,601 | 988 |
| Cost of other sales | 29 | 19 |
| Other operations and maintenance | 940 | 417 |
| Depreciation and amortization | 501 | 263 |
| Taxes other than income taxes | 184 | 113 |
| Total operating expenses | 3,255 | 1,800 |
| Operating income | 665 | 468 |
| Earnings from equity method investments | 106 | 46 |
| Interest expense, net of amounts capitalized | 200 | 119 |
| Other income (expense), net | 39 | 25 |
| Income taxes | 367 | 291 |
| Net income | $ 243 | $ 129 |

The changes in the table above for Southern Company Gas reflect the 12-month period in 2017 compared to the six-month period following the Merger closing on July 1, 2016. Additionally, earnings from equity method investments include Southern Company Gas' acquisition of a 50% equity interest in Southern Natural Gas Company, L.L.C. (SNG) completed in September 2016. See Note 12 to the financial statements under "Southern Company Gas" for additional information on Southern Company Gas' investment in SNG.

***Seasonality of Results***

During the period from November through March when natural gas usage and operating revenues are generally higher (Heating Season), more customers are connected to Southern Company Gas' distribution systems, and natural gas usage is higher in periods of colder weather. Occasionally in the summer, operating revenues are impacted due to peak usage by power generators in response to summer energy demands. Southern Company Gas' base operating expenses, excluding cost of natural gas, bad debt expense, and certain incentive compensation costs, are incurred relatively equally over any given year. Thus, operating results can vary significantly from quarter to quarter as a result of seasonality. For 2017, the percentage of operating revenues and net income generated during the Heating Season (January through March and November through December) were 67.3% and 73.7% , respectively. For July 1, 2016 through December 31, 2016, the percentage of operating revenues and net income generated during the Heating Season (November and December) were 67.1% and 96.5% , respectively. The 2017 net income generated during the Heating Season was significantly impacted by additional tax expense recorded in the fourth quarter resulting from the Tax Reform Legislation. See FUTURE EARNINGS POTENTIAL – " Income Tax Matters – Federal Tax Reform Legislation " herein for additional information.

**Other Business Activities**

Southern Company's other business activities include the parent company (which does not allocate operating expenses to business units), products and services in the areas of distributed generation, energy efficiency, and utility infrastructure, and investments in leveraged lease projects and telecommunications. These businesses are classified in general categories and may comprise the following subsidiaries: PowerSecure is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure; Southern Company Holdings, Inc. (Southern Holdings) invests in various projects, including leveraged lease projects; and Southern Linc provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber optics services within the Southeast.

On May 9, 2016, Southern Company acquired all of the outstanding stock of PowerSecure for an aggregate purchase price of $429 million . As a result, PowerSecure became a wholly-owned subsidiary of Southern Company. See Note 12 to the financial statements under " Southern Company – Acquisition of PowerSecure " for additional information.

A condensed statement of income for Southern Company's other business activities follows:

| | Amount | Increase (Decrease) from Prior Year | |
|---|---|---|---|
| | **2017** | **2017** | 2016 |
| | | *(in millions)* | |
| Operating revenues | **$ 571** | **$ 268** | $ 256 |
| Cost of other sales | **415** | **223** | 192 |
| Other operations and maintenance | **201** | **7** | 70 |
| Depreciation and amortization | **52** | **21** | 17 |
| Taxes other than income taxes | **3** | **—** | 1 |
| Total operating expenses | **671** | **251** | 280 |
| Operating income (loss) | **(100)** | **17** | (24) |
| Interest expense | **483** | **178** | 239 |
| Other income (expense), net | **(3)** | **28** | (24) |
| Income taxes (benefit) | **(307)** | **(91)** | (84) |
| Net income (loss) | **$ (279)** | **$ (42)** | $ (203) |

***Operating Revenues***

Southern Company's non-electric operating revenues for these other business activities increased $268 million , or 88.4% , in 2017 as compared to the prior year. The increase was primarily the result of the inclusion of PowerSecure results for the 12-month period in 2017 compared to eight months in 2016. Non-electric operating revenues for these other business activities increased $256 million , or 544.7% , in 2016 as compared to the prior year. The increase was primarily related to revenues from products and services following the acquisition of PowerSecure.

***Cost of Other Sales***

Cost of other sales increased $223 million and $192 million in 2017 and 2016, respectively. These cost increases were primarily related to sales of products and services by PowerSecure, which was acquired on May 9, 2016.

***Other Operations and Maintenance Expenses***

Other operations and maintenance expenses for these other business activities increased $7 million , or 3.6% , in 2017 as compared to the prior year. The increase was primarily due to a $44 million increase as a result of the inclusion of PowerSecure results for the 12-month period in 2017 compared to eight months in 2016, partially offset by a $35 million decrease in parent company expenses related to the Merger and the acquisition of PowerSecure. Other operations and maintenance expenses for these other business activities increased $70 million , or 56.5% , in 2016 as compared to the prior year. The increase was primarily due to $47 million in operations and maintenance expenses following the acquisition of PowerSecure and an increase in parent company expenses of $16 million related to the Merger and the acquisition of PowerSecure.

***Interest Expense***

Interest expense for these other business activities increased $178 million , or 58.4% , in 2017 as compared to the prior year primarily due to an increase in average outstanding long-term debt at the parent company. Interest expense for these other business activities increased $239 million , or 362.1% , in 2016 as compared to the prior year primarily due to an increase in outstanding long-term debt at the parent company primarily relating to financing a portion of the purchase price for the Merger.

***Other Income (Expense), Net***

Other income (expense), net for these other business activities increased $28 million in 2017 as compared to the prior year. The increase was primarily due to $30 million of expenses incurred in 2016 associated with bridge financing for the Merger. Other income (expense), net for these other business activities decreased $24 million in 2016 as compared to the prior year. The decrease was primarily due to an increase of $16 million related to the bridge financing for the Merger.

***Income Taxes (Benefit)***

The income tax benefit for these other business activities increased $91 million , or 42.1% , in 2017 as compared to the prior year primarily as a result of pre-tax earnings (losses) and net tax benefits related to the Tax Reform Legislation. The income tax benefit for these other business activities increased $84 million , or 63.6% , in 2016 as compared to the prior year primarily as a result of changes in pre-tax earnings (losses), partially offset by state income tax benefits realized in 2015.

See FUTURE EARNINGS POTENTIAL – " Income Tax Matters – Federal Tax Reform Legislation " herein and Note 5 to the financial statements for additional information.

**Effects of Inflation**

The electric operating companies and natural gas distribution utilities are subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Southern Power is party to long-term contracts reflecting market-based rates, including inflation expectations. Any adverse effect of inflation on Southern Company's results of operations has not been substantial in recent years.

**FUTURE EARNINGS POTENTIAL**

**General**

The four traditional electric operating companies operate as vertically integrated utilities providing electric service to customers within their service territories in the Southeast. The seven natural gas distribution utilities provide service to customers in their service territories in Illinois, Georgia, Virginia, New Jersey, Florida, Tennessee, and Maryland. Prices for electricity provided and natural gas distributed to retail customers are set by state PSCs or other applicable state regulatory agencies under cost-based regulatory principles. Prices for wholesale electricity sales and natural gas distribution, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. Southern Power continues to focus on long-term PPAs. See ACCOUNTING POLICIES – " Application of Critical Accounting Policies and Estimates – Utility Regulation " herein and Note 3 to the financial statements for additional information about regulatory matters. As discussed further herein, in October 2017, a wholly-owned subsidiary of Southern Company Gas entered into agreements for the sale of the assets of two of its natural gas distribution utilities, Elizabethtown Gas and Elkton Gas, to South Jersey Industries, Inc.

The results of operations for the past three years are not necessarily indicative of Southern Company's future earnings potential. The level of Southern Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Southern Company system's primary businesses of selling electricity and distributing natural gas. These factors include the traditional electric operating companies' and the natural gas distribution utilities' ability to maintain a constructive regulatory environment that allows for the timely recovery of prudently-incurred costs during a time of increasing costs and limited projected demand growth over the next several years. Plant Vogtle Units 3 and 4 construction and rate recovery are also major factors. In addition, the profitability of Southern Power's competitive wholesale business and successful additional investments in renewable and other energy projects are also major factors.

On December 22, 2017, the Tax Reform Legislation was signed into law and became effective on January 1, 2018, which among other things, reduces the federal corporate income tax rate to 21% and changes rates of depreciation and the business interest deduction. See " Income Tax Matters – Federal Tax Reform Legislation " and FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein and Notes 3 and 5 to the financial statements for additional information.

Future earnings for the electricity and natural gas businesses will be driven primarily by customer growth. Earnings in the electricity business will also depend upon maintaining and growing sales, considering, among other things, the adoption and/or penetration rates of increasingly energy-efficient technologies, increasing volumes of electronic commerce transactions, and higher multi-family home construction, all of which could contribute to a net reduction in customer usage. Earnings for both the electricity and natural gas businesses are subject to a variety of other factors. These factors include weather, competition, new energy contracts with other utilities and other wholesale customers, energy conservation practiced by customers, the use of alternative energy sources by customers, the prices of electricity and natural gas, the price elasticity of demand, and the rate of economic growth or decline in the service territory. In addition, the level of future earnings for the wholesale electric business also depends on numerous factors including regulatory matters, creditworthiness of customers, total electric generating capacity available and related costs, future acquisitions and construction of electric generating facilities, the impact of tax credits from renewable energy projects, and the successful remarketing of capacity as current contracts expire. Demand for electricity and natural gas is primarily driven by the pace of economic growth that may be affected by changes in regional and global economic conditions, which may impact future earnings. In addition, the volatility of natural gas prices has a significant impact on the natural gas distribution utilities' customer rates, long-term competitive position against other energy sources, and the ability of Southern Company Gas' gas marketing services and wholesale gas services businesses to capture value from locational and seasonal spreads. Additionally, changes in commodity prices subject a significant portion of Southern Company Gas' operations to earnings variability.

As part of its ongoing effort to adapt to changing market conditions, Southern Company continues to evaluate and consider a wide array of potential business strategies. These strategies may include business combinations, partnerships, and acquisitions involving other utility or non-utility businesses or properties, disposition of certain assets or businesses, internal restructuring, or some combination thereof. Furthermore, Southern Company may engage in new business ventures that arise from competitive and regulatory changes in the utility industry. Pursuit of any of the above strategies, or any combination thereof, may significantly affect the business operations, risks, and financial condition of Southern Company. See Note 12 to the financial statements for additional information regarding Southern Company's recent acquisition and disposition activities.

On October 15, 2017, a wholly-owned subsidiary of Southern Company Gas entered into agreements for the sale of the assets of two of its natural gas distribution utilities, Elizabethtown Gas and Elkton Gas, to South Jersey Industries, Inc. for a total cash purchase price of $1.7 billion. As of December 31, 2017, the net book value of the assets to be disposed of in the sale was approximately $1.3 billion, which includes approximately $0.5 billion of goodwill. The goodwill is not deductible for tax purposes and, as a result, a deferred tax liability has not yet been provided. Through the completion of the asset sales, Southern Company Gas intends to invest less than $0.1 billion in capital additions required for ordinary business operations of these assets. The completion of each asset sale is subject to the satisfaction or waiver of certain conditions, including, among other customary closing conditions, the receipt of required regulatory approvals, including the FERC, the Federal Communications Commission, the New Jersey BPU, and, with respect to the sale of Elkton Gas, the Maryland PSC. Southern Company Gas and South Jersey Industries, Inc. made joint filings on December 22, 2017 and January 16, 2018 with the New Jersey BPU and the Maryland PSC, respectively, requesting regulatory approval. The asset sales are expected to be completed by the end of the third quarter 2018.

In addition, Southern Power is pursuing the sale of a 33% equity interest in a newly-formed holding company that owns substantially all of Southern Power's solar assets, which, if successful, is expected to close in the middle of 2018.

The ultimate outcome of these matters cannot be determined at this time.

**Environmental Matters**

The Southern Company system's operations are regulated by state and federal environmental agencies through a variety of laws and regulations governing air, water, land, and protection of other natural resources. The Southern Company system maintains a comprehensive environmental compliance strategy to assess upcoming requirements and compliance costs associated with these environmental laws and regulations. The costs, including capital expenditures and operations and maintenance costs, required to comply with environmental laws and regulations may impact future unit retirement and replacement decisions, results of operations, cash flows, and financial condition. Compliance costs may result from the installation of additional environmental controls, closure and monitoring of CCR facilities, unit retirements, and adding or changing fuel sources for certain existing units, as well as related upgrades to the transmission system. A major portion of these compliance costs are expected to be recovered through existing ratemaking provisions. The ultimate impact of the environmental laws and regulations discussed below will depend on various factors, such as state adoption and implementation of requirements, the availability and cost of any deployed control technology, and the outcome of pending and/or future legal challenges.

New or revised environmental laws and regulations could affect many areas of the traditional electric operating companies', Southern Power's, and the natural gas distribution utilities' operations. The impact of any such changes cannot be determined at this time. Environmental compliance costs could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis for the traditional electric operating companies and the natural gas distribution utilities or through long-term wholesale agreements for the traditional electric operating companies and Southern Power . Further, increased costs that are recovered through regulated rates could contribute to reduced demand for electricity and natural gas , which could negatively affect results of operations, cash flows, and financial condition. Additionally, many commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity and natural gas .

The Southern Company system's commitment to the environment has been demonstrated in many ways, including participating in partnerships resulting in approximately $126 million of funding that has restored or enhanced more than 1.7 million acres of habitat since 2003; the removal of more than 15 million pounds of trash and debris from waterways through the Renew Our Rivers program; a 21% reduction in surface water withdrawal from 2015 to 2016; reductions in $SO_2$ and $NO_X$ air emissions of 95% and 85%, respectively, since 1990; the reduction of mercury air emissions of over 90% since 2005; and the Southern Company system's changing energy mix.

Through 2017 , the traditional electric operating companies have invested approximately $12.9 billion in environmental capital retrofit projects to comply with environmental requirements, with annual totals of approximately $0.9 billion, $0.5 billion, and

$0.9 billion for 2017 , 2016 , and 2015 , respectively. Although the timing, requirements, and estimated costs could change as environmental laws and regulations are adopted or modified, as compliance plans are revised or updated, and as legal challenges to rules are initiated or completed, the Southern Company system's current compliance strategy estimates capital expenditures of $2.8 billion from 2018 through 2022 , with annual totals of approximately $1.1 billion , $0.3 billion , $0.4 billion , $0.5 billion , and $0.5 billion for 2018 , 2019 , 2020 , 2021 , and 2022 , respectively. These estimates do not include any potential compliance costs associated with the regulation of $CO_2$ emissions from fossil fuel-fired electric generating units. See " Global Climate Issues " herein for additional information. The Southern Company system also anticipates expenditures associated with ash pond closure and ground water monitoring under the Disposal of Coal Combustion Residuals from Electric Utilities rule (CCR Rule), which are reflected in the Company's ARO liabilities. See FINANCIAL CONDITION AND LIQUIDITY – " Capital Requirements and Contractual Obligations " herein and Note 1 to the financial statements under " Asset Retirement Obligations and Other Costs of Removal " for additional information.

***Environmental Laws and Regulations***

*Air Quality*

The EPA has set National Ambient Air Quality Standards (NAAQS) for six air pollutants (carbon monoxide, lead, nitrogen dioxide, ozone, particulate matter, and $SO_2$ ), which it reviews and revises periodically. Revisions to these standards can require additional emission controls, improvements in control efficiency, or fuel changes which can result in increased compliance and operational costs. NAAQS requirements can also adversely affect the siting of new facilities. In 2015, the EPA published a more stringent eight-hour ozone NAAQS. The EPA plans to complete designations for this rule by no later than April 30, 2018 and intends to designate an eight-county area within metropolitan Atlanta as nonattainment . No other areas within the Southern Company system's electric service territory have been or are anticipated to be designated nonattainment under the 2015 ozone NAAQS. In 2010, the EPA revised the NAAQS for $SO_2$ , establishing a new one-hour standard, and is completing designations in multiple phases. The EPA has issued several rounds of area designations and no areas in the vicinity of Southern Company system -owned $SO_2$ sources have been designated nonattainment under the 2010 one-hour $SO_2$ NAAQS. However, final eight-hour ozone and $SO_2$ one-hour designations for certain areas are still pending and, if other areas are designated as nonattainment in the future, increased compliance costs could result.

In 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) and its $NO_X$ annual, $NO_X$ seasonal, and $SO_2$ annual programs. CSAPR is an emissions trading program that addresses the impacts of the interstate transport of $SO_2$ and $NO_X$ emissions from fossil fuel-fired power plants located in upwind states in the eastern half of the U.S. on air quality in downwind states. The Southern Company system has fossil fuel-fired generation in several states subject to these requirements. In October 2016, the EPA published a final rule that revised the CSAPR seasonal $NO_X$ program, establishing more stringent $NO_X$ emissions budgets in Alabama , Mississippi , and Texas . The EPA also removed North Carolina from the CSAPR $NO_X$ seasonal program and completely removed Florida from all CSAPR programs. Georgia's seasonal $NO_X$ budget remains unchanged. The outcome of ongoing CSAPR litigation, to which Mississippi Power is a party, could have an impact on the State of Mississippi's allowance allocations under the CSAPR seasonal $NO_X$ program. Increases in either future fossil fuel-fired generation or the cost of CSAPR allowances could have a negative financial impact on results of operations for Southern Company .

The EPA finalized regional haze regulations in 2005 and 2017. These regulations require states, tribal governments, and various federal agencies to develop and implement plans to reduce pollutants that impair visibility and demonstrate reasonable progress toward the goal of restoring natural visibility conditions in certain areas, including national parks and wilderness areas. States must submit a revised state implementation plan (SIP) to the EPA by July 31, 2021, demonstrating reasonable progress towards achieving visibility improvement goals. State implementation of reasonable progress could require further reductions in $SO_2$ or $NO_X$ emissions, which could result in increased compliance costs.

In 2015, the EPA published a final rule requiring certain states (including Alabama, Florida, Georgia, Mississippi, North Carolina, and Texas ) to revise or remove the provisions of their SIPs regulating excess emissions at industrial facilities, including electric generating facilities, during periods of startup, shut-down, or malfunction (SSM). The state excess emission rules provide necessary operational flexibility to affected units during periods of SSM and, if removed, could affect unit availability and result in increased operations and maintenance costs for the Southern Company system . The EPA has not yet responded to the SIP revisions proposed by states within the Southern Company system's traditional electric service territory.

*Water Quality*

In 2014, the EPA finalized requirements under Section 316(b) of the Clean Water Act (CWA) to regulate cooling water intake structures at existing power plants and manufacturing facilities in order to minimize their effects on fish and other aquatic life. The regulation requires plant-specific studies to determine applicable measures to protect organisms that either get caught on the intake screens (impingement) or are drawn into the cooling system (entrainment). The ultimate impact of this rule will depend on the outcome of these plant-specific studies and any additional protective measures required to be incorporated into each plant's National Pollutant Discharge Elimination System (NPDES) permit based on site-specific factors.

In 2015, the EPA finalized the steam electric effluent limitations guidelines (ELG) rule that set national standards for wastewater discharges from steam electric generating units. The rule prohibits effluent discharges of certain wastestreams and imposes stringent arsenic, mercury, selenium, and nitrate/nitrite limits on scrubber wastewater discharges. The revised technology-based limits and compliance dates may require extensive modifications to existing ash and wastewater management systems or the installation and operation of new ash and wastewater management systems. Compliance with the ELG rule is expected to require capital expenditures and increased operational costs primarily affecting the traditional electric operating companies' coal-fired electric generation. Compliance applicability dates range from November 1, 2018 to December 31, 2023 with state environmental agencies incorporating specific applicability dates in the NPDES permitting process based on information provided for each waste stream. The EPA has committed to a new rulemaking that could potentially revise the limitations and applicability dates of the ELG rule. The EPA expects to finalize this rulemaking in 2020.

In 2015, the EPA and the U.S. Army Corps of Engineers (Corps) jointly published a final rule that revised the regulatory definition of waters of the United States (WOTUS) for all CWA programs. The rule significantly expanded the scope of federal jurisdiction over waterbodies (such as rivers, streams, and canals), which could impact new generation projects and permitting and reporting requirements associated with the installation, expansion, and maintenance of transmission , distribution, and pipeline projects. On July 27, 2017, the EPA and the Corps proposed to rescind the 2015 WOTUS rule. The WOTUS rule has been stayed by the U.S. Court of Appeals for the Sixth Circuit since late 2015, but on January 22, 2018, the U.S. Supreme Court determined that federal district courts have jurisdiction over the pending challenges to the rule. On February 6, 2018, the EPA and the Corps published a final rule delaying implementation of the 2015 WOTUS rule to 2020.

*Coal Combustion Residuals*

In 2015, the EPA finalized non-hazardous solid waste regulations for the disposal of CCR, including coal ash and gypsum, in landfills and surface impoundments (CCR units) at active generating power plants. The CCR Rule requires CCR units to be evaluated against a set of performance criteria and potentially closed if minimum criteria are not met. Closure of existing CCR units could require installation of equipment and infrastructure to manage CCR in accordance with the rule. The EPA has announced plans to reconsider certain portions of the CCR Rule by no later than December 2019, which could result in changes to deadlines and corrective action requirements.

The EPA's reconsideration of the CCR Rule is due in part to a legislative development that impacts the potential oversight role of state agencies. Under the Water Infrastructure Improvements for the Nation Act, which became law in 2016, states are allowed to establish permit programs for implementing the CCR Rule. The Georgia Department of Natural Resources has incorporated the requirements of the CCR Rule into its solid waste regulations, which established additional requirements for all of Georgia Power's CCR units, and has requested that the EPA approve its state permitting program. The other states in the Southern Company system's electric service territory have not yet submitted plans to the EPA.

Based on cost estimates for closure and monitoring of ash ponds pursuant to the CCR Rule, Southern Company recorded AROs for each CCR unit in 2015. As further analysis is performed and closure details are developed, the traditional electric operating companies will continue to periodically update these cost estimates as necessary. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 1 to the financial statements under " Asset Retirement Obligations and Other Costs of Removal " for additional information regarding Southern Company's AROs as of December 31, 2017 .

*Environmental Remediation*

The Southern Company system must comply with environmental laws and regulations governing the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Southern Company system could incur substantial costs to clean up affected sites. The traditional electric operating companies and Southern Company Gas conduct studies to determine the extent of any required cleanup and Southern Company has recognized the estimated costs to clean up known impacted sites in its financial statements. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The traditional electric operating companies and the natural gas distribution utilities in Illinois, New Jersey, Georgia, and Florida have all received authority from their respective state PSCs or other applicable state regulatory agencies to recover approved environmental compliance costs through regulatory mechanisms. These regulatory mechanisms are adjusted annually or as necessary within limits approved by the state PSCs or other applicable state regulatory agencies. The traditional electric operating companies and Southern Company Gas may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under " Environmental Matters – Environmental Remediation " for additional information.

***Global Climate Issues***

In 2015, the EPA published final rules limiting $CO_2$ emissions from new, modified, and reconstructed fossil fuel-fired electric generating units and guidelines for states to develop plans to meet EPA-mandated $CO_2$ emission performance standards for existing units (known as the Clean Power Plan or CPP). In February 2016, the U.S. Supreme Court granted a stay of the CPP, which will remain in effect through the resolution of litigation in the U.S. Court of Appeals for the District of Columbia challenging the legality of the CPP and any review by the U.S. Supreme Court. On March 28, 2017, the U.S. President signed an executive order directing agencies to review actions that potentially burden the development or use of domestically produced energy resources, including review of the CPP and other $CO_2$ emissions rules. On October 10, 2017, the EPA published a proposed rule to repeal the CPP and, on December 28, 2017, published an advanced notice of proposed rulemaking regarding a CPP replacement rule.

In 2015, parties to the United Nations Framework Convention on Climate Change, including the United States, adopted the Paris Agreement, which established a non-binding universal framework for addressing greenhouse gas (GHG) emissions based on nationally determined contributions. On June 1, 2017, the U.S. President announced that the United States would withdraw from the Paris Agreement and begin renegotiating its terms. The ultimate impact of this agreement or any renegotiated agreement depends on its implementation by participating countries.

Domestic GHG policies may emerge in the future requiring the United States to transition to a lower GHG emitting economy. The Southern Company system has transitioned from an electric generating mix of 71% coal and 11% natural gas in 2005 to 30% percent coal and 46% natural gas mix in 2017 and currently includes over 8,000 MWs of renewable projects. In addition, the Southern Company system has retired 4,226 MWs of coal- and oil-fired generating capacity since 2010 and converted 3,280 MWs of generating capacity from coal to natural gas since 2015. Southern Company Gas replaced 5,300 miles of bare steel and cast-iron pipe, resulting in removal of 2.5 million metric tons of GHG from its natural gas distribution system since 1998. Based on ownership or financial control of facilities, the Southern Company system's 2016 GHG emissions ($CO_2$ equivalent) were approximately 99 million metric tons, with 2017 emissions estimated at 96 million metric tons. This equates to a reduction of 27% between 2005 and 2016 and a preliminary estimate of 30% through 2017. To better represent GHG emission reductions, the Southern Company system is transitioning to a maximum emission baseline year of 2007 and a baseline calculation methodology consistent with the EPA's Greenhouse Gas Reporting Program methodology. On a preliminary basis, these baseline adjustments result in an estimated GHG emission reduction of 36% from 2007 through 2017.

**FERC Matters**

***Market-Based Rate Authority***

The traditional electric operating companies and Southern Power have authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In 2015, the FERC issued an order finding that the traditional electric operating companies' and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The FERC directed the traditional electric operating companies and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional electric operating companies and Southern Power filed a request for rehearing and filed their response with the FERC in 2015.

In December 2016, the traditional electric operating companies and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. On May 17, 2017, the FERC accepted the traditional electric operating companies' and Southern Power's compliance filing accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

On October 25, 2017, the FERC issued an order in response to the traditional electric operating companies' and Southern Power's June 29, 2017 triennial updated market power analysis. The FERC directed the traditional electric operating companies and Southern Power to show cause within 60 days why market-based rate authority should not be revoked in certain areas adjacent to the area presently under mitigation in accordance with the February 2, 2017 order or to provide a mitigation plan to further address market power concerns. On November 10, 2017, the traditional electric operating companies and Southern Power responded to the FERC and proposed to resolve matters by applying the alternative mitigation authorized by the February 2, 2017 order to the adjacent areas made the subject of the October 25, 2017 order.

The ultimate outcome of these matters cannot be determined at this time.

***Southern Company Gas***

At December 31, 2017, Southern Company Gas' midstream operations business was involved in two gas pipeline construction projects, the Atlantic Coast Pipeline project and the PennEast Pipeline project, which received FERC approval in October 2017 and January 2018, respectively. Southern Company Gas' portion of the expected capital expenditures for these projects total approximately $586 million . These projects, along with Southern Company Gas' existing pipelines, are intended to provide diverse sources of natural gas supplies to customers, resolve current and long-term supply planning for new capacity, enhance system reliability, and generate economic development in the areas served.

On August 1, 2017, the Dalton Pipeline was placed in service as authorized by the FERC and transportation service for customers commenced. See Note 4 to the financial statements for additional information.

**Regulatory Matters**

***Alabama Power***

Alabama Power 's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the Alabama PSC. Alabama Power currently recovers its costs from the regulated retail business primarily through Rate RSE, Rate CNP, Rate ECR, and Rate NDR. In addition, the Alabama PSC issues accounting orders to address current events impacting Alabama Power. See Note 3 to the financial statements under " Regulatory Matters – Alabama Power " for additional information regarding Alabama Power's rate mechanisms and accounting orders.

*Rate RSE*

The Alabama PSC has adopted Rate RSE that provides for periodic annual adjustments based upon Alabama Power's projected weighted cost of equity (WCE) compared to an allowable range. Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate RSE adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. If Alabama Power's actual retail return is above the allowed WCE range, the excess will be refunded to customers unless otherwise directed by the Alabama PSC; however, there is no provision for additional customer billings should the actual retail return fall below the WCE range.

At December 31, 2016, Alabama Power's retail return exceeded the allowed WCE range which resulted in Alabama Power establishing a $73 million Rate RSE refund liability. In accordance with an Alabama PSC order issued on February 14, 2017, Alabama Power applied the full amount of the refund to reduce the under recovered balance of Rate CNP PPA as discussed further below.

Effective in January 2017, Rate RSE increased 4.48%, or $245 million annually. At December 31, 2017, Alabama Power's actual retail return was within the allowed WCE range. On December 1, 2017, Alabama Power made its required annual Rate RSE submission to the Alabama PSC of projected data for calendar year 2018. Projected earnings were within the specified range; therefore, retail rates under Rate RSE remained unchanged for 2018.

In conjunction with Rate RSE, Alabama Power has an established retail tariff that provides for an adjustment to customer billings to recognize the impact of a change in the statutory income tax rate. As a result of Tax Reform Legislation, the application of this tariff would reduce annual retail revenue by approximately $250 million over the remainder of 2018. The ultimate outcome of this matter cannot be determined at this time.

*Rate CNP PPA*

Alabama Power's retail rates, approved by the Alabama PSC, provide for adjustments under Rate CNP to recognize the placing of new generating facilities into retail service. Alabama Power may also recover retail costs associated with certificated PPAs under Rate CNP PPA. On March 7, 2017, the Alabama PSC issued a consent order that Alabama Power leave in effect the current Rate

CNP PPA factor for billings for the period April 1, 2017 through March 31, 2018. No adjustment to Rate CNP PPA is expected in 2018.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, Alabama Power eliminated the under recovered balance in Rate CNP PPA at December 31, 2016, which totaled approximately $142 million. As discussed herein under "Rate RSE," Alabama Power utilized the full amount of its $73 million Rate RSE refund liability to reduce the amount of the Rate CNP PPA under recovery and reclassified the remaining $69 million to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of Alabama Power's next depreciation study, which is expected to occur within the next two to four years. Alabama Power's current depreciation study became effective January 1, 2017.

*Rate CNP Compliance*

Rate CNP Compliance allows for the recovery of Alabama Power's retail costs associated with laws, regulations, and other such mandates directed at the utility industry involving the environment, security, reliability, safety, sustainability, or similar considerations impacting Alabama Power's facilities or operations. Rate CNP Compliance is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Compliance costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. Revenues for Rate CNP Compliance, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will have no significant effect on revenues or net income, but will affect annual cash flow. Changes in Rate CNP Compliance-related operations and maintenance expenses and depreciation generally will have no effect on net income.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, Alabama Power reclassified $36 million of its under recovered balance in Rate CNP Compliance to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of Alabama Power's next depreciation study, which is expected to occur within the next two to four years. Alabama Power's current depreciation study became effective January 1, 2017.

On December 5, 2017, the Alabama PSC issued a consent order that Alabama Power leave in effect for 2018 the factors associated with Alabama Power's compliance costs for the year 2017, with any under-collected amount for prior years deemed recovered before any current year amounts. Any under recovered amounts associated with 2018 will be reflected in the 2019 filing.

*Environmental Accounting Order*

Based on an order from the Alabama PSC, Alabama Power is allowed to establish a regulatory asset to record the unrecovered investment costs, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure associated with future unit retirements caused by environmental regulations. The regulatory asset will be amortized and recovered over the affected unit's remaining useful life, as established prior to the decision regarding early retirement through Rate CNP Compliance. See " Environmental Matters – Environmental Laws and Regulations " herein for additional information regarding environmental regulations.

***Georgia Power***

Georgia Power's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the Georgia PSC. Georgia Power currently recovers its costs from the regulated retail business through the 2013 ARP, which includes traditional base tariff rates, Demand-Side Management (DSM) tariffs, Environmental Compliance Cost Recovery (ECCR) tariffs, and Municipal Franchise Fee (MFF) tariffs. In addition, financing costs on certified project costs related to the construction of Plant Vogtle Units 3 and 4 are being collected through the NCCR tariff and fuel costs are collected through a separate fuel cost recovery tariff. See Note 3 to the financial statements under " Regulatory Matters – Georgia Power " for additional information.

*Rate Plans*

Pursuant to the terms and conditions of a settlement agreement related to Southern Company's acquisition of Southern Company Gas approved by the Georgia PSC in April 2016, the 2013 ARP will continue in effect until December 31, 2019, and Georgia Power will be required to file its next base rate case by July 1, 2019. Furthermore, through December 31, 2019, Georgia Power and Atlanta Gas Light Company each will retain their respective merger savings, net of transition costs, as defined in the settlement agreement; through December 31, 2022, such net merger savings applicable to each will be shared on a 60/40 basis with their respective customers; thereafter, all merger savings will be retained by customers. See Note 3 to the financial statements under " Regulatory Matters – Georgia Power – Rate Plans " for additional information regarding the 2013 ARP and Note 12 to the financial statements under " Southern Company – Merger with Southern Company Gas " for additional information regarding the Merger.

In accordance with the 2013 ARP, the Georgia PSC approved increases to tariffs effective January 1, 2016 as follows: (1) traditional base tariff rates by approximately $49 million; (2) ECCR tariff by approximately $75 million; (3) DSM tariffs by approximately $3 million; and (4) MFF tariff by approximately $13 million, for a total increase in base revenues of approximately $140 million. There were no changes to these tariffs in 2017.

Under the 2013 ARP, Georgia Power's retail ROE is set at 10.95% and earnings are evaluated against a retail ROE range of 10.00% to 12.00%. Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. In 2015, Georgia Power's retail ROE was within the allowed retail ROE range. In 2016, Georgia Power's retail ROE exceeded 12.00%, and Georgia Power will refund to retail customers approximately $44 million in 2018, as approved by the Georgia PSC on January 16, 2018. In 2017, Georgia Power's retail ROE was within the allowed retail ROE range, subject to review and approval by the Georgia PSC.

On January 19, 2018, the Georgia PSC issued an order on the Tax Reform Legislation, which was amended on February 16, 2018 (Tax Order). In accordance with the Tax Order, Georgia Power is required to submit its analysis of the Tax Reform Legislation and related recommendations to address the related impacts on Georgia Power 's cost of service and annual revenue requirements by March 6, 2018. The ultimate outcome of this matter cannot be determined at this time.

*Integrated Resource Plan*

See " Environmental Matters " herein for additional information regarding proposed and final EPA rules and regulations, including revisions to ELG for steam electric power plants and additional regulations of CCR and $CO_2$ .

In July 2016, the Georgia PSC approved Georgia Power's triennial Integrated Resource Plan (2016 IRP) including the decertification and retirement of Plant Mitchell Units 3, 4A, and 4B ( 217 MWs) and Plant Kraft Unit 1 ( 17 MWs), as well as the decertification of the Intercession City unit ( 143 MWs total capacity). In August 2016, the Plant Mitchell and Plant Kraft units were retired and Georgia Power sold its 33% ownership interest in the Intercession City unit to Duke Energy Florida, LLC.

Additionally, the Georgia PSC approved Georgia Power's environmental compliance strategy and related expenditures proposed in the 2016 IRP, including measures taken to comply with existing government-imposed environmental mandates, subject to limits on expenditures for Plant McIntosh Unit 1 and Plant Hammond Units 1 through 4.

The Georgia PSC approved the reclassification of the remaining net book value of Plant Mitchell Unit 3 and costs associated with materials and supplies remaining at the unit retirement date to a regulatory asset. Recovery of the unit's net book value will continue through December 31, 2019, as provided in the 2013 ARP. The timing of the recovery of the remaining balance of the unit's net book value as of December 31, 2019 and costs associated with materials and supplies remaining at the unit retirement date was deferred for consideration in Georgia Power's 2019 base rate case.

The Georgia PSC also approved the Renewable Energy Development Initiative (REDI) to procure an additional 1,200 MWs of renewable resources primarily utilizing market-based prices established through a competitive bidding process with expected in-service dates between 2018 and 2021. Additionally, 200 MWs of self-build capacity for use by Georgia Power was approved, as well as consideration for no more than 200 MWs of capacity as part of a renewable commercial and industrial program.

In 2017, Georgia Power filed for and received certification for 510 MWs of REDI utility-scale PPAs for solar generation resources, which are expected to be in operation by the end of 2019. Georgia Power also filed for and received approval to develop several solar generation projects to fulfill the approved self-build capacity.

In the 2016 IRP, the Georgia PSC also approved recovery of costs up to $99 million through June 30, 2019 to preserve nuclear generation as an option at a future generation site in Stewart County, Georgia. On March 7, 2017, the Georgia PSC approved Georgia Power's decision to suspend work at the site due to changing economics, including lower load forecasts and fuel costs. The timing of recovery for costs incurred of approximately $50 million is expected to be determined by the Georgia PSC in a future Georgia Power rate case.

*Storm Damage Recovery*

Georgia Power is accruing $30 million annually through December 31, 2019, as provided in the 2013 ARP, for incremental operating and maintenance costs of damage from major storms to its transmission and distribution facilities. Hurricanes Irma and Matthew caused significant damage to Georgia Power's transmission and distribution facilities during September 2017 and October 2016, respectively. The incremental restoration costs related to these hurricanes deferred in Georgia Power's regulatory asset for storm damage totaled approximately $260 million . At December 31, 2017, the total balance in Georgia Power's regulatory asset related to storm damage was $333 million . The rate of storm damage cost recovery is expected to be adjusted as part of Georgia Power's next base rate case required to be filed by July 1, 2019. As a result of this regulatory treatment, costs related to storms are not expected to have a material impact on Southern Company's financial statements. See Note 3 to the financial statements under " Regulatory Matters – Georgia Power – Storm Damage Recovery " for additional information regarding Georgia Power's storm damage reserve.

***Gulf Power***

On April 4, 2017, the Florida PSC approved the 2017 Rate Case Settlement Agreement among Gulf Power and three intervenors with respect to Gulf Power's request in 2016 to increase retail base rates. Among the terms of the 2017 Rate Case Settlement Agreement, Gulf Power increased rates effective with the first billing cycle in July 2017 to provide an annual overall net customer impact of approximately $54.3 million . The net customer impact consisted of a $62.0 million increase in annual base revenues, less an annual purchased power capacity cost recovery clause credit for certain wholesale revenues of approximately $8 million through December 2019. In addition, Gulf Power continued its authorized retail ROE midpoint ( 10.25% ) and range ( 9.25% to 11.25% ) and is deemed to have a maximum equity ratio of 52.5% for all retail regulatory purposes. Gulf Power also began amortizing the regulatory asset associated with the investment balances remaining after the retirement of Plant Smith Units 1 and 2 ( 357 MWs) over 15 years effective January 1, 2018 and implemented new depreciation rates effective January 1, 2018. The 2017 Rate Case Settlement Agreement also resulted in a $32.5 million write-down of Gulf Power's ownership of Plant Scherer Unit 3 ( 205 MWs), which was recorded in the first quarter 2017. The remaining issues related to the inclusion of Gulf Power's investment in Plant Scherer Unit 3 in retail rates have been resolved as a result of the 2017 Rate Case Settlement Agreement, including recoverability of certain costs associated with the ongoing ownership and operation of the unit through the environmental cost recovery clause.

The 2017 Rate Case Settlement Agreement set forth a process for addressing the revenue requirement effects of the Tax Reform Legislation through a prospective change to Gulf Power's base rates. Under the terms of the 2017 Rate Case Settlement Agreement, by March 1, 2018, Gulf Power must identify the revenue requirements impacts and defer them to a regulatory asset or regulatory liability to be considered for prospective application in a change to base rates in a limited scope proceeding before the Florida PSC. In lieu of this approach, on February 14, 2018, the parties to the 2017 Rate Case Settlement Agreement filed a new stipulation and settlement agreement (2018 Tax Reform Settlement Agreement) with the Florida PSC. If approved, the 2018 Tax Reform Settlement Agreement will result in annual reductions of $18.2 million to Gulf Power's base rates and $15.6 million to Gulf Power's environmental cost recovery rates effective beginning the first calendar month following approval.

The 2018 Tax Reform Settlement Agreement also provides for a one-time refund of $69.4 million for the retail portion of unprotected (not subject to normalization) deferred tax liabilities through Gulf Power's fuel cost recovery rate over the remainder of 2018. In addition, a limited scope proceeding to address the flow back of protected deferred tax liabilities will be initiated by May 1, 2018 and Gulf Power will record a regulatory liability for the related 2018 amounts eligible to be returned to customers consistent with IRS normalization principles. Unless otherwise agreed to by the parties to the 2018 Tax Reform Settlement Agreement, amounts recorded in this regulatory liability will be refunded to retail customers in 2019 through Gulf Power's fuel cost recovery rate.

If the 2018 Tax Reform Settlement Agreement is approved, the 2017 Rate Case Settlement Agreement will be amended to increase Gulf Power's maximum equity ratio from 52.5% to 53.5% for regulatory purposes.

The ultimate outcome of these matters cannot be determined at this time.

***Mississippi Power***

On February 7, 2018, Mississippi Power revised its annual projected PEP filing for 2018 to reflect the impacts of the Tax Reform Legislation. The revised filing requests an increase of $26 million in annual revenues, based on a performance adjusted ROE of 9.33% and an increased equity ratio of 55%. The ultimate outcome of this matter cannot be determined at this time.

***Southern Company Gas***

The natural gas distribution utilities are subject to regulation and oversight by their respective state regulatory agencies for the rates charged to their customers and other matters. These agencies approve rates designed to provide the opportunity to generate revenues to recover all prudently-incurred costs, including a return on rate base sufficient to pay interest on debt and provide a reasonable ROE.

The natural gas market for Atlanta Gas Light was deregulated in 1997. Accordingly, marketers, rather than a traditional utility, sell natural gas to end-use customers in Georgia and handle customer billing functions. Atlanta Gas Light earns revenue for its distribution services by charging rates to its customers based primarily on monthly fixed charges that are set by the Georgia PSC and adjusted periodically.

With the exception of Atlanta Gas Light, the natural gas distribution utilities are authorized by the relevant regulatory agencies in the states in which they serve to use natural gas cost recovery mechanisms that adjust rates to reflect changes in the wholesale cost of natural gas and ensure recovery of all costs prudently incurred in purchasing natural gas for customers. Natural gas cost recovery revenues are adjusted for differences in actual recoverable natural gas costs and amounts billed in current regulated rates. Changes in the billing factor will not have a significant effect on revenues or net income, but will affect cash flows. In addition to natural gas cost recovery mechanisms, there are other cost recovery mechanisms, such as regulatory riders, which vary by utility but allow recovery of certain costs, such as those related to infrastructure replacement programs, as well as environmental remediation and energy efficiency plans. See Note 1 to the financial statements under " Cost of Natural Gas " for additional information.

*Regulatory Infrastructure Programs*

Certain of Southern Company Gas' natural gas distribution utilities are involved in ongoing capital projects associated with infrastructure improvement programs that have been previously approved by their applicable state regulatory agencies and provide an appropriate return on invested capital. These infrastructure improvement programs are designed to update or expand the natural gas distribution systems of the natural gas distribution utilities to improve reliability and meet operational flexibility and growth. Initial program lengths range from nine to 10 years, with completion dates ranging from 2020 through 2025. The total expected investment under these programs for 2018 is $395 million .

*Base Rate Cases*

On January 31, 2018, the Illinois Commerce Commission approved a $137 million increase in Nicor Gas' annual base rate revenues, including $93 million related to the recovery of investments under Nicor Gas' infrastructure program, effective February 8, 2018, based on a ROE of 9.8%.

The Illinois Commerce Commission issued an order effective January 25, 2018 that requires utilities in the state to record the impacts of the Tax Reform Legislation, including the reduction in the corporate income tax rate to 21% and the impact of excess deferred income taxes, as a regulatory liability. On February 20, 2018, the Illinois Commerce Commission granted Nicor Gas' application for rehearing to file revised base rates and tariffs, which Nicor Gas expects to file by the end of the second quarter 2018.

On December 1, 2017, Atlanta Gas Light filed its 2018 annual rate adjustment with the Georgia PSC. If approved, Atlanta Gas Light's annual base rate revenues will increase by $22 million, effective June 1, 2018. Atlanta Gas Light will file a revised rate adjustment to incorporate the effects of the Tax Reform Legislation in the first quarter 2018. The Georgia PSC is expected to rule on the revised requested increase in the second quarter 2018.

The ultimate outcome of these matters cannot be determined at this time.

***Fuel Cost Recovery***

The traditional electric operating companies each have established fuel cost recovery rates approved by their respective state PSCs. Fuel cost recovery revenues are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on Southern Company's revenues or net income, but will affect cash flow. The traditional electric operating companies continuously monitor their under or over recovered fuel cost balances and make appropriate filings with their state PSCs to adjust fuel cost recovery rates as necessary.

See Note 1 to the financial statements under " Revenues " and Note 3 to the financial statements under " Regulatory Matters – Alabama Power – Rate ECR " and " Regulatory Matters – Georgia Power – Fuel Cost Recovery " for additional information.

**Kemper County Energy Facility**

The Kemper County energy facility was approved by the Mississippi PSC as an IGCC facility in the 2010 CPCN proceedings, subject to a construction cost cap of $2.88 billion, net of $245 million of the Initial DOE Grants and excluding the Cost Cap Exceptions. The combined cycle and associated common facilities portions of the Kemper County energy facility were placed in service in August 2014. In December 2015, the Mississippi PSC issued the In-Service Asset Rate Order, authorizing rates that provided for the recovery of approximately $126 million annually related to the assets previously placed in service.

On June 21, 2017, the Mississippi PSC stated its intent to issue the Kemper Settlement Order (which occurred on July 6, 2017) directing Mississippi Power to pursue a settlement under which the Kemper County energy facility would be operated as a natural gas plant, rather than an IGCC plant, and address all issues associated with the Kemper County energy facility. The Kemper Settlement Order established the Kemper Settlement Docket for the purposes of pursuing a global settlement of the related costs.

On June 28, 2017, Mississippi Power notified the Mississippi PSC that it would begin a process to suspend operations and start-up activities on the gasifier portion of the Kemper County energy facility, given the uncertainty as to its future. At the time of project suspension, the total cost estimate for the Kemper County energy facility was approximately $7.38 billion, including approximately $5.95 billion of costs subject to the construction cost cap, and was net of the $137 million in Additional DOE Grants. In the aggregate, Mississippi Power had incurred charges of $3.07 billion ($1.89 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through May 31, 2017. Given the Mississippi PSC's stated intent regarding no further rate increase for the Kemper County energy facility and the subsequent suspension, cost recovery of the gasifier portions became no longer probable; therefore, Mississippi Power recorded an additional charge to income in June 2017 of $2.8 billion ($2.0 billion after tax), which included estimated costs associated with the gasifier portions of the plant and lignite mine.

On February 6, 2018, the Mississippi PSC voted to approve the Kemper Settlement Agreement related to cost recovery for the Kemper County energy facility among Mississippi Power, the MPUS, and certain intervenors. The Kemper Settlement Agreement provides for an annual revenue requirement of approximately $99.3 million for costs related to the Kemper County energy facility, which includes the impact of Tax Reform Legislation. The revenue requirement is based on (i) a fixed ROE for 2018 of 8.6%, excluding any performance adjustment, (ii) a ROE for 2019 calculated in accordance with PEP, excluding the performance adjustment, (iii) for future years, a performance-based ROE calculated pursuant to PEP, and (iv) amortization periods for the related regulatory assets and liabilities of eight years and six years, respectively. The revenue requirement also reflects a disallowance related to a portion of Mississippi Power's investment in the Kemper County energy facility requested for inclusion in rate base, which was recorded in the fourth quarter 2017 as an additional charge to income of approximately $78 million ($85 million net of accumulated depreciation of $7 million) pre-tax ($48 million after tax).

Under the Kemper Settlement Agreement, retail customer rates will reflect a reduction of approximately $26.8 million annually and include no recovery for costs associated with the gasifier portion of the Kemper County energy facility in 2018 or at any future date. On February 12, 2018, Mississippi Power made the required compliance filing with the Mississippi PSC. The Kemper Settlement Agreement also requires (i) the CPCN for the Kemper County energy facility to be modified to limit it to natural gas combined cycle operation and (ii) Mississippi Power to file a reserve margin plan with the Mississippi PSC by August 2018.

During the third and fourth quarters of 2017, Mississippi Power recorded charges to income of $242 million ($206 million after tax), including $164 million for ongoing project costs, estimated mine and gasifier-related costs, and certain termination costs during the suspension period prior to conclusion of the Kemper Settlement Docket, as well as the charge associated with the Kemper Settlement Agreement. Additional pre-tax cancellation costs, including mine and plant closure and contract termination costs, currently estimated at approximately $50 million to $100 million (excluding salvage), are expected to be incurred in 2018. Mississippi Power has begun efforts to dispose of or abandon the mine and gasifier-related assets.

Total pre-tax charges to income related to the Kemper County energy facility were $3.4 billion ($2.4 billion after tax) for the year ended December 31, 2017. In the aggregate, since the Kemper County energy facility project started, Mississippi Power has incurred charges of $6.2 billion ($4.1 billion after tax) through December 31, 2017.

As a result of the Mississippi PSC order on February 6, 2018, rate recovery for the Kemper County energy facility is resolved, subject to any future legal challenges.

See Note 3 to the financial statements under " Kemper County Energy Facility " for additional information.

***Litigation***

On April 26, 2016, a complaint against Mississippi Power was filed in Harrison County Circuit Court (Circuit Court) by Biloxi Freezing & Processing Inc., Gulfside Casino Partnership, and John Carlton Dean, which was amended and refiled on July 11, 2016 to include, among other things, Southern Company as a defendant. The individual plaintiff alleges that Mississippi Power and Southern Company violated the Mississippi Unfair Trade Practices Act. All plaintiffs have alleged that Mississippi Power and Southern Company concealed, falsely represented, and failed to fully disclose important facts concerning the cost and schedule of the Kemper County energy facility and that these alleged breaches have unjustly enriched Mississippi Power and Southern Company. The plaintiffs seek unspecified actual damages and punitive damages; ask the Circuit Court to appoint a receiver to oversee, operate, manage, and otherwise control all affairs relating to the Kemper County energy facility; ask the Circuit Court to revoke any licenses or certificates authorizing Mississippi Power or Southern Company to engage in any business related to the Kemper County energy facility in Mississippi; and seek attorney's fees, costs, and interest. The plaintiffs also seek an injunction to prevent any Kemper County energy facility costs from being charged to customers through electric rates. On June 23, 2017, the Circuit Court ruled in favor of motions by Southern Company and Mississippi Power and dismissed the case. On July 7, 2017, the plaintiffs filed notice of an appeal. Southern Company believes this legal challenge has no merit; however, an adverse outcome in this proceeding could have a material impact on Southern Company's results of operations, financial condition, and liquidity. Southern Company intends to vigorously defend itself in this matter and the ultimate outcome of this matter cannot be determined at this time.

On June 9, 2016, Treetop Midstream Services, LLC (Treetop) and other related parties filed a complaint against Mississippi Power, Southern Company, and SCS in the state court in Gwinnett County, Georgia. The complaint related to the cancelled $CO_2$ contract with Treetop and alleged fraudulent misrepresentation, fraudulent concealment, civil conspiracy, and breach of contract on the part of Mississippi Power, Southern Company, and SCS and sought compensatory damages of $100 million, as well as unspecified punitive damages. Southern Company, Mississippi Power, and SCS moved to compel arbitration pursuant to the terms of the $CO_2$ contract, which the court granted on May 4, 2017. On June 28, 2017, Treetop and other related parties filed a claim for arbitration requesting $500 million in damages. On December 28, 2017, Mississippi Power reached a settlement agreement with Treetop and other related parties and the arbitration was dismissed.

**Construction Program**

***Overview***

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. The Southern Company system intends to continue its strategy of developing and constructing new electric generating facilities, adding environmental modifications to certain existing units, expanding the electric transmission and distribution systems, and updating and expanding the natural gas distribution systems. For the traditional electric operating companies, major generation construction projects are subject to state PSC approval in order to be included in retail rates. While Southern Power generally constructs and acquires generation assets covered by long-term PPAs, any uncontracted capacity could negatively affect future earnings. Southern Company Gas is engaged in various infrastructure improvement programs designed to update or expand the natural gas distribution systems of the natural gas distribution utilities to improve reliability and meet operational flexibility and growth. The natural gas distribution utilities recover their investment and a return associated with these infrastructure programs through their regulated rates. The Southern Company system's construction program is currently estimated to total approximately $9.4 billion , $9.3 billion , $8.4 billion , $7.0 billion , and $6.9 billion for 2018 , 2019 , 2020 , 2021 , and 2022 , respectively.

The largest construction project currently underway in the Southern Company system is Plant Vogtle Units 3 and 4 (45.7% ownership interest by Georgia Power in the two units, each with approximately 1,100 MWs). See Note 3 to the financial statements under " Nuclear Construction " for additional information. See Note 12 to the financial statements under " Southern Power " for additional information about costs relating to Southern Power's acquisitions that involve construction of renewable energy facilities. See Note 3 to the financial statements under " Regulatory Matters – Southern Company Gas – Regulatory Infrastructure Programs " for additional information regarding infrastructure improvement programs at the natural gas distribution utilities.

Also see FINANCIAL CONDITION AND LIQUIDITY – " Capital Requirements and Contractual Obligations " herein for additional information regarding Southern Company's capital requirements for its subsidiaries' construction programs.

***Nuclear Construction***

*Vogtle 3 and 4 Agreement and EPC Contractor Bankruptcy*

In 2008, Georgia Power, acting for itself and as agent for the Vogtle Owners, entered into the Vogtle 3 and 4 Agreement. Under the terms of the Vogtle 3 and 4 Agreement, the Vogtle Owners agreed to pay a purchase price subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. Under the Toshiba Guarantee, Toshiba guaranteed certain payment obligations of the EPC Contractor, including any liability of the EPC Contractor for abandonment of work. In the first quarter 2016, Westinghouse delivered to the Vogtle Owners a total of $920 million of letters of credit from financial institutions (Westinghouse Letters of Credit) to secure a portion of the EPC Contractor's potential obligations under the Vogtle 3 and 4 Agreement.

Subsequent to the EPC Contractor bankruptcy filing, a number of subcontractors to the EPC Contractor alleged non-payment by the EPC Contractor for amounts owed for work performed on Plant Vogtle Units 3 and 4. Georgia Power, acting for itself and as agent for the Vogtle Owners, has taken actions to remove liens filed by these subcontractors through the posting of surety bonds. Related to such liens, certain subcontractors have filed, and additional subcontractors may file, actions against the EPC Contractor and the Vogtle Owners to preserve their payment rights with respect to such claims. All amounts associated with the removal of subcontractor liens and other EPC Contractor pre-petition accounts payable have been paid or accrued as of December 31, 2017.

On June 9, 2017, Georgia Power and the other Vogtle Owners and Toshiba entered into the Guarantee Settlement Agreement. Pursuant to the Guarantee Settlement Agreement, Toshiba acknowledged the amount of its obligation was $3.68 billion (Guarantee Obligations), of which Georgia Power's proportionate share was approximately $1.7 billion . The Guarantee Settlement Agreement provided for a schedule of payments for the Guarantee Obligations beginning in October 2017 and continuing through January 2021. Toshiba made the first three payments as scheduled. On December 8, 2017, Georgia Power, the other Vogtle Owners, certain affiliates of the Municipal Electric Authority of Georgia (MEAG Power), and Toshiba entered into Amendment No. 1 to the Guarantee Settlement Agreement (Guarantee Settlement Agreement Amendment). The Guarantee Settlement Agreement Amendment provided that Toshiba's remaining payment obligations under the Guarantee Settlement Agreement were due and payable in full on December 15, 2017, which Toshiba satisfied on December 14, 2017. Pursuant to the Guarantee Settlement Agreement Amendment, Toshiba was deemed to be the owner of certain pre-petition bankruptcy claims of Georgia Power, the other Vogtle Owners, and certain affiliates of MEAG Power against Westinghouse, and Georgia Power and the other Vogtle Owners surrendered the Westinghouse Letters of Credit.

Additionally, on June 9, 2017, Georgia Power, acting for itself and as agent for the other Vogtle Owners, and the EPC Contractor entered into the Vogtle Services Agreement, which was amended and restated on July 20, 2017. On July 20, 2017, the bankruptcy court approved the EPC Contractor's motion seeking authorization to (i) enter into the Vogtle Services Agreement, (ii) assume and assign to the Vogtle Owners certain project-related contracts, (iii) join the Vogtle Owners as counterparties to certain assumed project-related contracts, and (iv) reject the Vogtle 3 and 4 Agreement. The Vogtle Services Agreement, and the EPC Contractor's rejection of the Vogtle 3 and 4 Agreement, became effective upon approval by the DOE on July 27, 2017. The Vogtle Services Agreement will continue until the start-up and testing of Plant Vogtle Units 3 and 4 are complete and electricity is generated and sold from both units. The Vogtle Services Agreement is terminable by the Vogtle Owners upon 30 days' written notice.

Effective October 23, 2017, Georgia Power, acting for itself and as agent for the other Vogtle Owners, entered into a construction completion agreement with Bechtel, whereby Bechtel will serve as the primary contractor for the remaining construction activities for Plant Vogtle Units 3 and 4 (Bechtel Agreement). Facility design and engineering remains the responsibility of the EPC Contractor under the Vogtle Services Agreement. The Bechtel Agreement is a cost reimbursable plus fee arrangement, whereby Bechtel will be reimbursed for actual costs plus a base fee and an at-risk fee, which is subject to adjustment based on Bechtel's performance against cost and schedule targets. Each Vogtle Owner is severally (not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to Bechtel under the Bechtel Agreement. The Vogtle Owners may terminate the Bechtel Agreement at any time for their convenience, provided that the Vogtle Owners will be required to pay amounts related to work performed prior to the termination (including the applicable portion of the base fee), certain termination-related costs, and, at certain stages of the work, the applicable portion of the at-risk fee. Bechtel may terminate the Bechtel Agreement under certain circumstances, including certain Vogtle Owner suspensions of work, certain breaches of the Bechtel Agreement by the Vogtle Owners, Vogtle Owner insolvency, and certain other events. Pursuant to the Loan Guarantee Agreement between Georgia Power and the DOE, Georgia Power is required to obtain the DOE's approval of the Bechtel Agreement prior to obtaining any further advances under the Loan Guarantee Agreement.

On November 2, 2017, the Vogtle Owners entered into an amendment to their joint ownership agreements for Plant Vogtle Units 3 and 4 (as amended, Vogtle Joint Ownership Agreements) to provide for, among other conditions, additional Vogtle Owner approval requirements. Pursuant to the Vogtle Joint Ownership Agreements, the holders of at least 90% of the ownership interests in Plant Vogtle Units 3 and 4 must vote to continue construction if certain adverse events occur, including (i) the bankruptcy of Toshiba; (ii) termination or rejection in bankruptcy of certain agreements, including the Vogtle Services Agreement or the Bechtel Agreement; (iii) the Georgia PSC or Georgia Power determines that any of Georgia Power's costs relating to the construction of Plant Vogtle Units 3 and 4 will not be recovered in retail rates because such costs are deemed unreasonable or imprudent; or (iv) an increase in the construction budget contained in the seventeenth VCM report of more than $1 billion or extension of the project schedule contained in the seventeenth VCM report of more than one year . In addition, pursuant to the Vogtle Joint Ownership Agreements, the required approval of holders of ownership interests in Plant Vogtle Units 3 and 4 is at least (i) 90% for a change of the primary construction contractor and (ii) 67% for material amendments to the Vogtle Services Agreement or agreements with Southern Nuclear or the primary construction contractor, including the Bechtel Agreement. The Vogtle Joint Ownership Agreements also confirm that the Vogtle Owners' sole recourse against Georgia Power or Southern Nuclear for any action or inaction in connection with their performance as agent for the Vogtle Owners is limited to removal of Georgia Power and/or Southern Nuclear as agent, except in cases of willful misconduct.

*Regulatory Matters*

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4 with a certified capital cost of $4.418 billion . In addition, in 2009 the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows Georgia Power to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff up to the certified capital cost of $4.418 billion . As of December 31, 2017, Georgia Power had recovered approximately $1.6 billion of financing costs. On January 30, 2018, Georgia Power filed to decrease the NCCR tariff by approximately $50 million , effective April 1, 2018, pending Georgia PSC approval. The decrease reflects the payments received under the Guarantee Settlement Agreement, the Customer Refunds ordered by the Georgia PSC aggregating approximately $188 million , and the estimated effects of Tax Reform Legislation. The Customer Refunds were recognized as a regulatory liability as of December 31, 2017 and will be paid in three installments of $25 to each retail customer no later than the third quarter 2018.

Georgia Power is required to file semi-annual VCM reports with the Georgia PSC by February 28 and August 31 each year. In October 2013, in connection with the eighth VCM report, the Georgia PSC approved a stipulation (2013 Stipulation) between Georgia Power and the staff of the Georgia PSC to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate in accordance with the 2009 certification order until the completion of Plant Vogtle Unit 3, or earlier if deemed appropriate by the Georgia PSC and Georgia Power.

On December 20, 2016, the Georgia PSC voted to approve a settlement agreement (Vogtle Cost Settlement Agreement) resolving certain prudency matters in connection with the fifteenth VCM report. On December 21, 2017, the Georgia PSC voted to approve (and issued its related order on January 11, 2018) certain recommendations made by Georgia Power in the seventeenth VCM report and modifying the Vogtle Cost Settlement Agreement. The Vogtle Cost Settlement Agreement, as modified by the January 11, 2018 order, resolved the following regulatory matters related to Plant Vogtle Units 3 and 4: (i) none of the $3.3 billion of costs incurred through December 31, 2015 and reflected in the fourteenth VCM report should be disallowed from rate base on the basis of imprudence; (ii) the Contractor Settlement Agreement was reasonable and prudent and none of the amounts paid pursuant to the Contractor Settlement Agreement should be disallowed from rate base on the basis of imprudence; (iii) (a) capital costs incurred up to $5.680 billion would be presumed to be reasonable and prudent with the burden of proof on any party challenging such costs, (b) Georgia Power would have the burden to show that any capital costs above $5.680 billion were prudent, and (c) a revised capital cost forecast of $7.3 billion (after reflecting the impact of payments received under the Guarantee Settlement Agreement and Customer Refunds) is found reasonable; (iv) construction of Plant Vogtle Units 3 and 4 should be completed, with Southern Nuclear serving as project manager and Bechtel as primary contractor; (v) approved and deemed reasonable Georgia Power's revised schedule placing Plant Vogtle Units 3 and 4 in service in November 2021 and November 2022, respectively; (vi) confirmed that the revised cost forecast does not represent a cost cap and that prudence decisions on cost recovery will be made at a later date, consistent with applicable Georgia law; (vii) reduced the ROE used to calculate the NCCR tariff (a) from 10.95% (the ROE rate setting point authorized by the Georgia PSC in the 2013 ARP) to 10.00% effective January 1, 2016, (b) from 10.00% to 8.30% , effective January 1, 2020, and (c) from 8.30% to 5.30% , effective January 1, 2021 (provided that the ROE in no case will be less than Georgia Power's average cost of long-term debt); (viii) reduced the ROE used for AFUDC equity for Plant Vogtle Units 3 and 4 from 10.00% to Georgia Power's average cost of long-term debt, effective January 1, 2018; and (ix) agreed that upon Unit 3 reaching commercial operation, retail base rates would be adjusted to include carrying costs on those capital costs deemed prudent in the Vogtle Cost Settlement Agreement. The January 11, 2018 order also stated that if Plant Vogtle Units 3 and 4 are not commercially operational by June 1, 2021 and June 1, 2022, respectively, the ROE used to calculate the NCCR tariff will be further reduced by 10 basis points each month (but not lower than Georgia Power's average cost of long-term debt) until the respective unit is commercially operational. The ROE reductions negatively impacted earnings by approximately $20 million in 2016 and $25 million in 2017 and are estimated to have negative earnings impacts of approximately $120 million in 2018 and an aggregate of $585 million from 2019 to 2022. In its January 11, 2018 order, the Georgia PSC stated if other certain conditions and assumptions upon which Georgia Power's seventeenth VCM report are based do not materialize, both Georgia Power and the Georgia PSC reserve the right to reconsider the decision to continue construction.

On February 12, 2018, Georgia Interfaith Power & Light, Inc. and Partnership for Southern Equity, Inc. filed a petition appealing the Georgia PSC's January 11, 2018 order with the Fulton County Superior Court. Georgia Power believes the appeal has no merit; however, an adverse outcome in this appeal could have a material impact on Southern Company's results of operations, financial condition, and liquidity.

The IRS allocated PTCs to each of Plant Vogtle Units 3 and 4, which originally required the applicable unit to be placed in service before 2021. Under the Bipartisan Budget Act of 2018, Plant Vogtle Units 3 and 4 continue to qualify for PTCs. The nominal value of Georgia Power's portion of the PTCs is approximately $500 million per unit.

In its January 11, 2018 order, the Georgia PSC also approved $542 million of capital costs incurred during the seventeenth VCM reporting period (January 1, 2017 to June 30, 2017). The Georgia PSC has approved seventeen VCM reports covering the periods through June 30, 2017, including total construction capital costs incurred through that date of $4.4 billion . Georgia Power expects to file its eighteenth VCM report on February 28, 2018 requesting approval of approximately $450 million of construction capital costs (before payments received under the Guarantee Settlement Agreement and the Customer Refunds) incurred from July 1, 2017 through December 31, 2017. Georgia Power's CWIP balance for Plant Vogtle Units 3 and 4 was approximately $4.8 billion as of December 31, 2017, or $3.3 billion net of payments received under the Guarantee Settlement Agreement and the Customer Refunds.

The ultimate outcome of these matters cannot be determined at this time.

*Cost and Schedule*

Georgia Power's approximate proportionate share of the remaining estimated capital cost to complete Plant Vogtle Units 3 and 4 with in service dates of November 2021 and November 2022, respectively, is as follows:

| | | *(in billions)* |
|---|---|---|
| Project capital cost forecast | $ | 7.3 |
| Net investment as of December 31, 2017 | | (3.4) |
| **Remaining estimate to complete** | **$** | **3.9** |

Note: Excludes financing costs capitalized through AFUDC and is net of payments received under the Guarantee Settlement Agreement and the Customer Refunds.

Georgia Power estimates that its financing costs for construction of Plant Vogtle Units 3 and 4 will total approximately $3.1 billion , of which $1.6 billion had been incurred through December 31, 2017 .

As construction continues, challenges with management of contractors, subcontractors, and vendors, labor productivity and availability, fabrication, delivery, assembly, and installation of plant systems, structures, and components (some of which are based on new technology and have not yet operated in the global nuclear industry at this scale), or other issues could arise and change the projected schedule and estimated cost.

There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4 at the federal and state level and additional challenges may arise. Processes are in place that are designed to assure compliance with the requirements specified in the Westinghouse Design Control Document and the combined construction and operating licenses, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance matters, including the timely resolution of Inspections, Tests, Analyses, and Acceptance Criteria and the related approvals by the NRC, may arise, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs.

The ultimate outcome of these matters cannot be determined at this time.

*Other Matters*

As of December 31, 2017 , Georgia Power had borrowed $2.6 billion related to Plant Vogtle Units 3 and 4 costs through the Loan Guarantee Agreement and a multi-advance credit facility among Georgia Power, the DOE, and the FFB, which provides for borrowings of up to $3.46 billion , subject to the satisfaction of certain conditions. On September 28, 2017, the DOE issued a conditional commitment to Georgia Power for up to approximately $1.67 billion in additional guaranteed loans under the Loan Guarantee Agreement. This conditional commitment expires on June 30, 2018, subject to any further extension approved by the DOE. Final approval and issuance of these additional loan guarantees by the DOE cannot be assured and are subject to the negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information, including applicable covenants, events of default, mandatory prepayment events, and conditions to borrowing.

The ultimate outcome of these matters cannot be determined at this time.

**Income Tax Matters**

***Federal Tax Reform Legislation***

On December 22, 2017, the Tax Reform Legislation was signed into law and became effective on January 1, 2018. The Tax Reform Legislation, among other things, reduces the federal corporate income tax rate to 21%, retains normalization provisions for public utility property and existing renewable energy incentives, and repeals the corporate alternative minimum tax.

For businesses other than regulated utilities, the Tax Reform Legislation allows 100% bonus depreciation of qualified property acquired and placed in service between September 28, 2017 and January 1, 2023 and phases down by 20% each year until completely phased out for qualified property placed in service after December 31, 2027. Further, the business interest deduction is limited to 30% of taxable income excluding interest, net operating loss (NOL) carryforwards, and depreciation and amortization through December 31, 2021, and thereafter to 30% of taxable income excluding interest and NOL carryforwards.

Regulated utility businesses, including the majority of the operations of the traditional electric operating companies and the natural gas distribution companies, can continue deducting all business interest expense and are not eligible for bonus depreciation on capital assets acquired and placed in service after September 27, 2017. Projects with binding contracts before September 28, 2017 and placed in service after September 27, 2017 remain eligible for bonus depreciation under the Protecting Americans from Tax Hikes (PATH) Act.

In addition, under the Tax Reform Legislation, NOLs generated after December 31, 2017 can no longer be carried back to previous tax years but can be carried forward indefinitely, with utilization limited to 80% of taxable income of the subsequent tax year. The projected reduction of the consolidated income tax liability resulting from the tax rate reduction also delays the expected utilization of existing tax credit carryforwards.

For the year ended December 31, 2017, implementation of the Tax Reform Legislation resulted in an estimated net tax benefit of $264 million , a $0.4 billion decrease in regulatory assets, and a $6.9 billion increase in regulatory liabilities, primarily due to the impact of the reduction of the corporate income tax rate on deferred tax assets and liabilities . Also, the OCI ending balance at December 31, 2017 includes $30 million of stranded excess deferred tax balances, which will be adjusted through retained earnings in subsequent periods.

The Tax Reform Legislation is subject to further interpretation and guidance from the IRS, as well as each respective state's adoption. In addition, the regulatory treatment of certain impacts of the Tax Reform Legislation is subject to the discretion of the FERC and relevant state regulatory bodies. On January 31, 2018, SCS, on behalf of the traditional electric operating companies, filed with the FERC a reduction to the open access transmission tariff charge for 2018 to reflect the revised federal corporate income tax rate. See Note 3 to the financial statements under "Regulatory Matters" for additional information regarding the traditional electric operating companies' and the natural gas distribution utilities' rate filings to reflect the impacts of the Tax Reform Legislation.

On February 9, 2018, the Bipartisan Budget Act of 2018 was signed into law. Included in the tax extenders portion of the law were provisions extending PTCs on advanced nuclear power facilities and ITCs on qualified fuel cells. A subsidiary of PowerSecure installed fuel cells in 2017 which are expected to qualify for approximately $80 million of ITCs; however, the impact of the related tax benefits would be substantially offset by additional required payments under the applicable purchase contracts. Should Southern Company have a NOL in 2018, all of these ITCs may not be fully realized in 2018. See Note 3 to the financial statements under "Nuclear Construction" for additional information on the PTCs relating to advanced nuclear power facilities.

See FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein and Note 5 to the financial statements under " Current and Deferred Income Taxes " for additional information.

The ultimate outcome of these matters cannot be determined at this time.

***Bonus Depreciation***

Under the Tax Reform Legislation, projects with binding contracts prior to September 28, 2017 and placed in service after September 27, 2017 remain eligible for bonus depreciation under the PATH Act. The PATH Act allowed for 50% bonus depreciation for 2015 through 2017, 40% bonus depreciation for 2018, and 30% bonus depreciation for 2019 and certain long-lived assets placed in service in 2020. Based on provisional estimates, bonus depreciation is expected to result in positive cash flows of approximately $870 million for the 2017 tax year and approximately $290 million for the 2018 tax year. Should Southern Company have a NOL in 2018, all of these cash flows may not be fully realized in 2018 . All projected tax benefits previously received for bonus depreciation related to the Kemper IGCC were repaid in connection with third quarter 2017 estimated tax payments. Additionally, Southern Company will record an abandonment loss on its 2018 corporate income tax return, which may not be fully realized should Southern Company have a NOL in 2018. See Notes 3 and 5 to the financial statements under " Kemper County Energy Facility " and " Current and Deferred Income Taxes – Net Operating Loss ," respectively, for additional information. The ultimate outcome of these matters cannot be determined at this time.

***Tax Credits***

The Tax Reform Legislation retained the renewable energy incentives that were included in the PATH Act. The PATH Act allows for 30% ITC for solar projects that commence construction by December 31, 2019; 26% ITC for solar projects that commence construction in 2020; 22% ITC for solar projects that commence construction in 2021; and a permanent 10% ITC for solar projects that commence construction on or after January 1, 2022. In addition, the PATH Act allows for 100% PTC for wind projects that commenced construction in 2016; 80% PTC for wind projects that commenced construction in 2017; 60% PTC for wind projects that commence construction in 2018; and 40% PTC for wind projects that commence construction in 2019. Wind projects commencing construction after 2019 will not be entitled to any PTCs. The Company has received ITCs and PTCs in connection with investments in solar, wind, and biomass facilities primarily at Southern Power and Georgia Power. See Note 1 to the financial statements under "Income and Other Taxes" and Note 5 to the financial statements under "Current and Deferred Income Taxes – Tax Credit Carryforwards" for additional information regarding the utilization and amortization of credits and the tax benefit related to basis differences.

***Southern Power***

In September 2017, Southern Power began a legal entity reorganization of various direct and indirect subsidiaries that own and operate substantially all of its solar facilities, including certain subsidiaries owned in partnership with various third parties. The reorganization is expected to be substantially completed in the first quarter 2018 and is expected to result in estimated tax benefits totaling between $50 million and $55 million related to certain changes in state apportionment rates and net operating loss carryforward utilization that will be recorded in the first quarter 2018. Southern Power is pursuing the sale of a 33% equity interest in the newly-formed holding company owning these solar assets. The ultimate outcome of this matter cannot be determined at this time.

**Other Matters**

Southern Company and its subsidiaries are involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Southern Company and its subsidiaries are subject to certain claims and legal actions arising in the ordinary course of business. The business activities of Southern Company's subsidiaries are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as standards for air, water, land, and protection of other natural resources, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by $CO_2$ and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters.

The ultimate outcome of such pending or potential litigation or regulatory matters cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Southern Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

In 2016, the SEC began conducting a formal investigation of Southern Company and Mississippi Power concerning the estimated costs and expected in-service date of the Kemper County energy facility. On November 30, 2017, the SEC staff notified Southern Company that it had concluded its investigation with no recommended enforcement action.

***Litigation***

On January 20, 2017, a purported securities class action complaint was filed against Southern Company, certain of its officers, and certain former Mississippi Power officers in the U.S. District Court for the Northern District of Georgia, Atlanta Division, by Monroe County Employees' Retirement System on behalf of all persons who purchased shares of Southern Company's common stock between April 25, 2012 and October 29, 2013. The complaint alleges that Southern Company, certain of its officers, and certain former Mississippi Power officers made materially false and misleading statements regarding the Kemper County energy facility in violation of certain provisions under the Securities Exchange Act of 1934, as amended. The complaint seeks, among other things, compensatory damages and litigation costs and attorneys' fees. On June 12, 2017, the plaintiffs filed an amended complaint that provided additional detail about their claims, increased the purported class period by one day, and added certain other former Mississippi Power officers as defendants. On July 27, 2017, the defendants filed a motion to dismiss the plaintiffs' amended complaint with prejudice, to which the plaintiffs filed an opposition on September 11, 2017.

On February 27, 2017, Jean Vineyard filed a shareholder derivative lawsuit in the U.S. District Court for the Northern District of Georgia that names as defendants Southern Company, certain of its directors, certain of its officers, and certain former Mississippi Power officers. The complaint alleges that the defendants caused Southern Company to make false or misleading statements regarding the Kemper County energy facility cost and schedule. Further, the complaint alleges that the defendants were unjustly enriched and caused the waste of corporate assets. The plaintiff seeks to recover, on behalf of Southern Company, unspecified actual damages and, on her own behalf, attorneys' fees and costs in bringing the lawsuit. The plaintiff also seeks certain changes to Southern Company's corporate governance and internal processes. On March 27, 2017, the court deferred this lawsuit until 30 days after certain further action in the purported securities class action complaint discussed above.

On May 15, 2017, Helen E. Piper Survivor's Trust filed a shareholder derivative lawsuit in the Superior Court of Gwinnett County, State of Georgia and, on May 31, 2017, Judy Mesirov filed a shareholder derivative lawsuit in the U.S. District Court for the Northern District of Georgia. Each of these lawsuits names as defendants Southern Company, certain of its directors, certain of its officers, and certain former Mississippi Power officers. Each complaint alleges that the individual defendants, among other things, breached their fiduciary duties in connection with schedule delays and cost overruns associated with the construction of the Kemper County energy facility. Each complaint further alleges that the individual defendants authorized or failed to correct false and misleading statements regarding the Kemper County energy facility schedule and cost and failed to implement necessary internal controls to prevent harm to Southern Company. Each plaintiff seeks to recover, on behalf of Southern Company, unspecified actual damages and disgorgement of profits and, on its behalf, attorneys' fees and costs in bringing the lawsuit. Each plaintiff also seeks certain unspecified changes to Southern Company's corporate governance and internal processes. On August 15, 2017, these two shareholder derivative lawsuits were consolidated in the U.S. District Court for the Northern District of Georgia and the court deferred the consolidated case until 30 days after certain further action in the purported securities class action complaint discussed above.

Southern Company believes these legal challenges have no merit; however, an adverse outcome in any of these proceedings could have an impact on Southern Company's results of operations, financial condition, and liquidity. Southern Company will vigorously defend itself in these matters, the ultimate outcome of which cannot be determined at this time.

***Investments in Leveraged Leases***

A subsidiary of Southern Holdings has several leveraged lease agreements, with original terms ranging up to 45 years , which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. Southern Company reviews all important lease assumptions at least annually, or more frequently if events or changes in circumstances indicate that a change in assumptions has occurred or may occur. These assumptions include the effective tax rate, the residual value, the credit quality of the lessees, and the timing of expected tax cash flows. See Note 1 to the financial statements under " Leveraged Leases " for additional information.

The ability of the lessees to make required payments to the Southern Holdings subsidiary is dependent on the operational performance of the assets. In the last six months of 2017, the financial and operational performance of one of the lessees and the associated generation assets has raised significant concerns about the short-term ability of the generation assets to produce cash flows sufficient to support ongoing operations and the lessee's contractual obligations and its ability to make the remaining semi-annual lease payments to the Southern Holdings subsidiary beginning in June 2018. These operational challenges may also impact the expected residual value of the assets at the end of the lease term in 2047. If the June 2018 (or any future) lease payment is not paid in full, the Southern Holdings subsidiary may be unable to make its corresponding payment to the holders of the underlying non-recourse debt related to the generation assets. Failure to make the required payment to the debtholders would represent an event of default that would give the debtholders the right to foreclose on, and take ownership of, the generation assets from the Southern Holdings subsidiary, in effect terminating the lease and resulting in the write-off of the related lease receivable which had a balance of approximately $86 million as of December 31, 2017 . Southern Company has evaluated the recoverability of the lease receivable and the expected residual value of the generation assets at the end of the lease under various scenarios and has concluded that its investment in the leveraged lease is not impaired as of December 31, 2017 . Southern Company will continue to monitor the operational performance of the underlying assets and evaluate the ability of the lessee to continue to make the required lease payments, including the lease payment due in June 2018. The ultimate outcome of this matter cannot be determined at this time.

*Natural Gas Storage*

A wholly-owned subsidiary of Southern Company Gas owns and operates a natural gas storage facility consisting of two salt dome caverns in Louisiana. Periodic integrity tests are required in accordance with rules of the Louisiana Department of Natural Resources (DNR). In August 2017, in connection with an ongoing integrity project, updated seismic mapping indicated the proximity of one of the caverns to the edge of the salt dome may be less than the required minimum and could result in Southern Company Gas retiring the cavern early. At December 31, 2017, the facility's property, plant, and equipment had a net book value of $112 million, of which the cavern itself represents approximately 20%. A potential early retirement of this cavern is dependent upon several factors including compliance with an order from the Louisiana DNR detailing the requirements to place the cavern back in service, which includes, among other things, obtaining core samples to determine the composition of the sheath surrounding the edge of the salt dome.

The cavern continues to maintain its pressures and overall structural integrity. Southern Company Gas intends to monitor the cavern and comply with the Louisiana DNR order through 2020 and place the cavern back in service in 2021. These events were considered in connection with Southern Company Gas' annual long-lived asset impairment analysis, which determined there was no impairment as of December 31, 2017. Any changes in results of monitoring activities, rates at which expiring capacity contracts are re-contracted, timing of placing the cavern back in service, or Louisiana DNR requirements could trigger impairment. Further, early retirement of the cavern could trigger impairment of other long-lived assets associated with the natural gas storage facility. The ultimate outcome of this matter cannot be determined at this time, but could have a significant impact on Southern Company's financial statements.

**ACCOUNTING POLICIES**

**Application of Critical Accounting Policies and Estimates**

Southern Company prepares its consolidated financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on Southern Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

*Utility Regulation*

Southern Company's traditional electric operating companies and natural gas distribution utilities, which collectively comprised approximately 86% of Southern Company's total operating revenues for 2017 , are subject to retail regulation by their respective state PSCs or other applicable state regulatory agencies and wholesale regulation by the FERC. These regulatory agencies set the rates the traditional electric operating companies and the natural gas distribution utilities are permitted to charge customers based on allowable costs, including a reasonable ROE. As a result, the traditional electric operating companies and the natural gas distribution utilities apply accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the traditional electric operating companies and the natural gas distribution utilities; therefore, the accounting estimates inherent in specific costs such as depreciation, AROs, and pension and other postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and any requirement to refund these regulatory liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

*Kemper County Energy Facility Rate Recovery*

For periods prior to the second quarter 2017, significant accounting estimates included Kemper County energy facility estimated construction costs, project completion date, and rate recovery. Mississippi Power recorded total pre-tax charges to income related to the Kemper County energy facility of $428 million ($264 million after tax) in 2016, $365 million ($226 million after tax) in 2015, $868 million ($536 million after tax) in 2014, and $1.2 billion ($729 million after tax) in prior years.

As a result of the Mississippi PSC's June 21, 2017 stated intent to issue an order (which occurred on July 6, 2017) directing Mississippi Power to pursue a settlement under which the Kemper County energy facility would be operated as a natural gas plant rather than an IGCC plant, as well as Mississippi Power's June 28, 2017 suspension of the operation and start-up of the gasifier portion of the Kemper County energy facility, the estimated construction costs and project completion date are no longer considered significant accounting estimates.

Given the Mississippi PSC's stated intent regarding no further rate increase for the Kemper County energy facility and the subsequent suspension, cost recovery of the gasifier portions became no longer probable; therefore, Mississippi Power recorded an additional charge to income in June 2017 of $2.8 billion ($2.0 billion after tax), which included estimated costs associated with the gasifier portions of the plant and lignite mine. During the third and fourth quarters of 2017, Mississippi Power recorded charges to income of $242 million ($206 million after tax), including $164 million for ongoing project costs, estimated mine and gasifier-related costs, and certain termination costs during the suspension period prior to conclusion of the Kemper Settlement Docket, as well as a charge of $78 million associated with the Kemper Settlement Agreement.

In the aggregate, since the Kemper County energy facility project started, Mississippi Power has incurred charges of $6.20 billion ($4.14 billion after tax) through December 31, 2017. See Note 14 to the financial statements for additional information on the individual charges by quarter.

As a result of the Mississippi PSC order on February 6, 2018, rate recovery for the Kemper County energy facility is resolved, subject to any future legal challenges, and no longer represents a critical accounting estimate.

See Note 3 to the financial statements under " Kemper County Energy Facility " for additional information.

### *Accounting for Income Taxes*

The consolidated income tax provision and deferred income tax assets and liabilities, as well as any unrecognized tax benefits and valuation allowances, require significant judgment and estimates. These estimates are supported by historical tax return data, reasonable projections of taxable income, and interpretations of applicable tax laws and regulations across multiple taxing jurisdictions. The effective tax rate reflects the statutory tax rates and calculated apportionments for the various states in which the Southern Company system operates.

Southern Company files a consolidated federal income tax return and various state income tax returns, some of which are combined or unitary. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. Certain deductions and credits can be limited at the consolidated or combined level resulting in NOL and tax credit carryforwards that would not otherwise result on a stand-alone basis. Utilization of NOL and tax credit carryforwards and the assessment of valuation allowances are based on significant judgment and extensive analysis of the Company's current financial position and result of operations, including currently available information about future years, to estimate when future taxable income will be realized.

Current and deferred state income tax liabilities and assets are estimated based on laws of multiple states that determine the income to be apportioned to their jurisdictions. States utilize various formulas to calculate the apportionment of taxable income, primarily using sales, assets, or payroll within the jurisdiction compared to the consolidated totals. In addition, each state varies as to whether a stand-alone, combined, or unitary filing methodology is required. The calculation of deferred state taxes considers apportionment factors and filing methodologies that are expected to apply in future years. The apportionments and methodologies which are ultimately finalized in a manner inconsistent with expectations could have a material effect on Southern Company's financial statements.

Given the significant judgment involved in estimating NOL and tax credit carryforwards and multi-state apportionments for all subsidiaries, Southern Company considers state deferred income tax liabilities and assets to be critical accounting estimates.

### *Federal Tax Reform Legislation*

Following the enactment of the Tax Reform Legislation, the SEC staff issued Staff Accounting Bulletin 118 – "Income Tax Accounting Implications of the Tax Cuts and Jobs Act" (SAB 118), which provides for a measurement period of up to one year from the enactment date to complete accounting under GAAP for the tax effects of the legislation. Due to the complex and comprehensive nature of the enacted tax law changes, and their application under GAAP, Southern Company considers all amounts recorded in the financial statements as a result of the Tax Reform Legislation to be "provisional" as discussed in SAB 118 and subject to revision. Southern Company is awaiting additional guidance from industry and income tax authorities in order to finalize its accounting. The ultimate impact of the Tax Reform Legislation on deferred income tax assets and liabilities and the related regulatory assets and liabilities cannot be determined at this time. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation " herein and Notes 3 and 5 to the financial statements under "Regulatory Matters" and "Current and Deferred Income Taxes," respectively, for additional information.

***Asset Retirement Obligations***

AROs are computed as the fair value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities.

The liability for AROs primarily relates to facilities that are subject to the CCR Rule, principally ash ponds, and the decommissioning of the Southern Company system's nuclear facilities – Alabama Power's Plant Farley and Georgia Power's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2. In addition, the Southern Company system has retirement obligations related to various landfill sites, asbestos removal, mine reclamation, land restoration related to solar and wind facilities, and disposal of polychlorinated biphenyls in certain transformers. The Southern Company system also has identified retirement obligations related to certain electric transmission and distribution facilities, certain wireless communication towers, property associated with the Southern Company system's rail lines and natural gas pipelines, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded as the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO.

The cost estimates for AROs related to the disposal of CCR are based on information using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure. As further analysis is performed and closure details are developed, the traditional electric operating companies will continue to periodically update these cost estimates as necessary. See FUTURE EARNINGS POTENTIAL – " Environmental Matters – Environmental Laws and Regulations – Coal Combustion Residuals " herein and Note 1 to the financial statements under " Asset Retirement Obligations and Other Costs of Removal " and " Nuclear Decommissioning " for additional information.

Given the significant judgment involved in estimating AROs, Southern Company considers the liabilities for AROs to be critical accounting estimates.

***Pension and Other Postretirement Benefits***

Southern Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining Southern Company's pension and other postretirement benefit expense are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on pension and other postretirement benefit plan assets is based on Southern Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. Southern Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to Southern Company's target asset allocation. For purposes of determining its liability related to the pension and other postretirement benefit plans, Southern Company discounts the future related cash flows using a single-point discount rate for each plan developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments. For 2015 and prior years, Southern Company computed the interest cost component of its net periodic pension and other postretirement benefit plan expense using the same single-point discount rate. Beginning in 2016, Southern Company adopted a full yield curve approach for calculating the interest cost component whereby the discount rate for each year is applied to the liability for that specific year. As a result, the interest cost component of net periodic pension and other postretirement benefit plan expense decreased by approximately $96 million in 2016.

The following table illustrates the sensitivity to changes in Southern Company's long-term assumptions with respect to the assumed discount rate, the assumed salaries, and the assumed long-term rate of return on plan assets:

| Change in Assumption | Increase/(Decrease) in Total Benefit Expense for 2018 | Increase/(Decrease) in Projected Obligation for Pension Plan at December 31, 2017 | Increase/(Decrease) in Projected Obligation for Other Postretirement Benefit Plans at December 31, 2017 |
|---|---|---|---|
| | | *(in millions)* | |
| 25 basis point change in discount rate | $40/$(38) | $504/$(476) | $68/$(65) |
| 25 basis point change in salaries | $24/$(23) | $119/$(115) | $–/$– |
| 25 basis point change in long-term return on plan assets | $33/$(33) | N/A | N/A |

N/A – Not applicable

See Note 2 to the financial statements for additional information regarding pension and other postretirement benefits.

***Goodwill and Other Intangible Assets***

The acquisition method of accounting requires the assets acquired and liabilities assumed to be recorded at the date of acquisition at their respective estimated fair values. Southern Company recognizes goodwill as of the acquisition date, as a residual over the fair values of the identifiable net assets acquired. Goodwill is tested for impairment on an annual basis in the fourth quarter of the year as well as on an interim basis as events and changes in circumstances occur. Primarily as a result of the acquisitions of Southern Company Gas and PowerSecure in 2016, goodwill totaled approximately $6.3 billion at December 31, 2017 .

Definite-lived intangible assets acquired are amortized over the estimated useful lives of the respective assets to reflect the pattern in which the economic benefits of the intangible assets are consumed. Whenever events or changes in circumstances indicate that the carrying amount of the intangible assets may not be recoverable, the intangible assets will be reviewed for impairment. Primarily as a result of the acquisitions of Southern Company Gas and PowerSecure and PPA fair value adjustments resulting from Southern Power's acquisitions, other intangible assets, net of amortization totaled approximately $873 million at December 31, 2017 .

The judgments made in determining the estimated fair value assigned to each class of assets acquired and liabilities assumed, as well as asset lives, can significantly impact Southern Company's results of operations. Fair values and useful lives are determined based on, among other factors, the expected future period of benefit of the asset, the various characteristics of the asset, and projected cash flows. As the determination of an asset's fair value and useful life involves management making certain estimates and because these estimates form the basis for the determination of whether or not an impairment charge should be recorded, Southern Company considers these estimates to be critical accounting estimates.

See Note 1 to the financial statements under " Goodwill and Other Intangible Assets and Liabilities " for additional information regarding Southern Company's goodwill and other intangible assets and Note 12 to the financial statements for additional information related to Southern Company's recent acquisitions and proposed dispositions.

***Derivatives and Hedging Activities***

Derivative instruments are recorded on the balance sheets as either assets or liabilities measured at their fair value, unless the transactions qualify for the normal purchases or normal sales scope exception and are instead subject to traditional accrual accounting. For those transactions that do not qualify as a normal purchase or normal sale, changes in the derivatives' fair values are recognized concurrently in earnings unless specific hedge accounting criteria are met. If the derivatives meet those criteria, derivative gains and losses offset related results of the hedged item in the income statement in the case of a fair value hedge, or gains and losses are deferred in OCI until the hedged transaction affects earnings in the case of a cash flow hedge. Certain subsidiaries of Southern Company enter into energy-related derivatives that are designated as regulatory hedges where gains and losses are initially recorded as regulatory liabilities and assets and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through billings to customers.

Southern Company uses derivative instruments to reduce the impact to the results of operations due to the risk of changes in the price of natural gas, to manage fuel hedging programs per guidelines of state regulatory agencies, and to mitigate residual changes in the price of electricity, weather, interest rates, and foreign currency exchange rates. The fair value of commodity derivative instruments used to manage exposure to changing prices reflects the estimated amounts that Southern Company would receive or pay to terminate or close the contracts at the reporting date. To determine the fair value of the derivative instruments, Southern Company utilizes market data or assumptions that market participants would use in pricing the derivative asset or liability, including assumptions about risk and the risks inherent in the inputs of the valuation technique.

Southern Company classifies derivative assets and liabilities based on the lowest level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy. The determination of the fair value of the derivative instruments incorporates various required factors. These factors include:

- the creditworthiness of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit);
- events specific to a given counterparty; and
- the impact of Southern Company's nonperformance risk on its liabilities.

Given the assumptions used in pricing the derivative asset or liability, Southern Company considers the valuation of derivative assets and liabilities a critical accounting estimate. See FINANCIAL CONDITION AND LIQUIDITY – " Market Price Risk " herein for more information.

***Contingent Obligations***

Southern Company is subject to a number of federal and state laws and regulations as well as other factors and conditions that subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. Southern Company periodically evaluates its exposure to such risks and records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect Southern Company's results of operations, cash flows, or financial condition.

**Recently Issued Accounting Standards**

***Revenue***

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers* (ASC 606), replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the new standard is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

Most of Southern Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity or natural gas without a defined contractual term , as well as longer-term contractual commitments, including PPAs and non-derivative natural gas asset management and optimization arrangements.

Southern Company has completed the evaluation of all revenue streams and determined that the adoption of ASC 606 will not change the current timing of revenue recognition for such transactions. Some revenue arrangements, such as certain PPAs , energy-related derivatives, and alternative revenue programs, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed or presented separately from revenues under ASC 606 on Southern Company's financial statements. Southern Company has concluded contributions in aid of construction are not in scope for ASC 606 and will continue to be accounted for as an offset to property, plant, and equipment.

The new standard is effective for reporting periods beginning after December 15, 2017. Southern Company applied the modified retrospective method of adoption effective January 1, 2018. Southern Company also utilized practical expedients which allowed it to apply the standard to open contracts at the date of adoption and to reflect the aggregate effect of all modifications when identifying performance obligations and allocating the transaction price for contracts modified before the effective date. Under the modified retrospective method of adoption, prior year reported results are not restated; however, a cumulative-effect adjustment to retained earnings at January 1, 2018 is recorded. In addition, quarterly disclosures will include comparative information on 2018 financial statement line items under current guidance. The adoption of ASC 606 did not result in a cumulative-effect adjustment .

***Leases***

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged and there is no change to the accounting for existing leveraged leases. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018 and Southern Company will adopt the new standard effective January 1, 2019.

Southern Company is currently implementing an information technology system along with the related changes to internal controls and accounting policies that will support the accounting for leases under ASU 2016-02. In addition, Southern Company has substantially completed a detailed inventory and analysis of its leases. In terms of rental charges and duration of contracts, the most significant leases relate to cellular towers and PPAs where certain of Southern Company's subsidiaries are the lessee and to land and outdoor lighting where certain of Southern Company's subsidiaries are the lessor. The traditional electric operating companies are currently analyzing pole attachment agreements, and a lease determination has not been made at this time. While Southern Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on Southern Company's balance sheet.

***Other***

In November 2016, the FASB issued ASU No. 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash* (ASU 2016-18). ASU 2016-18 eliminates the need to reflect transfers between cash and restricted cash in operating, investing, and financing activities in the statement of cash flows. Upon adoption, the net change in cash and cash equivalents during the period will include amounts generally described as restricted cash or restricted cash equivalents. ASU 2016-18 is effective for fiscal years beginning after December 15, 2017, and will be applied retrospectively to each period presented. Southern Company adopted ASU 2016-18 effective January 1, 2018 with no material impact on its financial statements.

On January 26, 2017, the FASB issued ASU No. 2017-04, *Intangibles – Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment* (ASU 2017-04). ASU 2017-04 removes the requirement to compare the implied fair value of goodwill with the carrying amount as part of Step 2 of the goodwill impairment test. Under the new standard, the goodwill impairment loss will be measured as the excess of a reporting unit's carrying amount over its fair value, not exceeding the total amount of goodwill allocated to that reporting unit, which may increase the frequency of goodwill impairment charges if a future goodwill impairment test does not pass the Step 1 evaluation. ASU 2017-04 is effective prospectively for periods beginning on or after December 15, 2019, with early adoption permitted. Southern Company adopted ASU 2017-04 effective January 1, 2018 with no impact on its financial statements.

On March 10, 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017-07). ASU 2017-07 requires that an employer report the service cost component in the same line item or items as other compensation costs and requires the other components of net periodic pension and postretirement benefit costs to be separately presented in the income statement outside of income from operations. Additionally, only the service cost component is eligible for capitalization, when applicable. However, all cost components remain eligible for capitalization under FERC regulations. ASU 2017-07 will be applied retrospectively for the presentation of the service cost component and the other components of net periodic pension and postretirement benefit costs in the income statement. The capitalization of only the service cost component of net periodic pension and postretirement benefit costs in assets will be applied on a prospective basis. ASU 2017-07 is effective for periods beginning after December 15, 2017. The presentation changes required for net periodic pension and postretirement benefit costs will result in a decrease in Southern Company's operating income and an increase in other income for 2016 and 2017 and are expected to result in a decrease in operating income and an increase in other income for 2018. Southern Company adopted ASU 2017-07 effective January 1, 2018 with no material impact on its financial statements.

On August 28, 2017, the FASB issued ASU No. 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities* (ASU 2017-12), amending the hedge accounting recognition and presentation requirements. ASU 2017-12 makes more financial and non-financial hedging strategies eligible for hedge accounting, amends the related presentation and disclosure requirements, and simplifies hedge effectiveness assessment requirements. ASU 2017-12 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. Southern Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

## FINANCIAL CONDITION AND LIQUIDITY

### Overview

Earnings in all periods presented were negatively affected by charges associated with the Kemper IGCC; however, Southern Company's financial condition remained stable at December 31, 2017 .

The Southern Company system's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. The Southern Company system's capital expenditures and other investing activities include investments to meet projected long-term demand requirements, including to build new electric generation facilities, to maintain existing electric generation facilities, to comply with environmental regulations including adding environmental modifications to certain existing electric generating units, to expand and improve electric transmission and distribution facilities, to update and expand natural gas distribution systems, and for restoration following major storms. Operating cash flows provide a substantial portion of the Southern Company system's cash needs. For the three-year period from 2018 through 2020 , Southern Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Southern Company plans to finance future cash needs in excess of its operating cash flows primarily by accessing borrowings from financial institutions and through debt and equity issuances in the capital markets. Southern Company intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit arrangements to meet future capital and liquidity needs. See " Sources of Capital ," " Financing Activities ," and " Capital Requirements and Contractual Obligations " herein for additional information.

Southern Company's investments in the qualified pension plans and the nuclear decommissioning trust funds increased in value as of December 31, 2017 as compared to December 31, 2016 . No contributions to the qualified pension plan were made for the year ended December 31, 2017 and no mandatory contributions to the qualified pension plans are anticipated during 2018 . See " Contractual Obligations " herein and Notes 1 and 2 to the financial statements under " Nuclear Decommissioning " and " Pension Plans ," respectively, for additional information.

Net cash provided from operating activities in 2017 totaled $6.4 billion , an increase of $1.5 billion from 2016 . The increase in net cash provided from operating activities was primarily due to increases of $1.2 billion related to operating activities of Southern Company Gas, which was acquired on July 1, 2016, and $1.0 billion related to voluntary contributions to the qualified pension plan in 2016, partially offset by the timing of vendor payments. Net cash provided from operating activities in 2016 totaled $4.9 billion , a decrease of $1.4 billion from 2015 . Significant changes in operating cash flow for 2016 as compared to 2015 included approximately $1.0 billion of voluntary contributions to the qualified pension plan in 2016 and a $1.2 billion increase in unutilized ITCs and PTCs.

Net cash used for investing activities in 2017 , 2016 , and 2015 totaled $7.2 billion , $20.0 billion , and $7.3 billion , respectively. The cash used for investing activities in 2017 was primarily due to the traditional electric operating companies' installation of equipment to comply with environmental standards and construction of electric generation, transmission, and distribution facilities, capital expenditures for Southern Company Gas' infrastructure replacement programs, and Southern Power's renewable acquisitions. The cash used for investing activities in 2016 was primarily due to the closing of the Merger, the acquisition of PowerSecure, Southern Company Gas' investment in SNG, the traditional electric operating companies' construction of electric generation, transmission, and distribution facilities and installation of equipment at electric generating facilities to comply with environmental standards, and Southern Power's acquisitions and construction of renewable facilities and a natural gas facility. The cash used for investing activities in 2015 was primarily due to the traditional electric operating companies' gross property additions for installation of equipment at electric generating facilities to comply with environmental standards and construction of electric generation, transmission, and distribution facilities, Southern Power's acquisitions of solar facilities, and purchases of nuclear fuel.

Net cash provided from financing activities totaled $1.0 billion in 2017 primarily due to net issuances of long-term and short-term debt, partially offset by common stock dividend payments. Net cash provided from financing activities totaled $15.7 billion in 2016 primarily due to issuances of long-term debt and common stock associated with completing the Merger and funding the subsidiaries' continuous construction programs, Southern Power's acquisitions, and Southern Company Gas' investment in SNG, partially offset by redemptions of long-term debt and common stock dividend payments. Net cash provided from financing activities totaled $1.7 billion in 2015 primarily due to issuances of long-term debt and common stock and an increase in short-term debt, partially offset by common stock dividend payments and redemptions of long-term debt and preferred and preference stock. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes in 2017 included decreases of $7.3 billion and $0.8 billion in accumulated deferred income taxes and deferred charges related to income taxes, respectively, and an increase of $7.0 billion in deferred credits related to income taxes primarily resulting from the impacts of the Tax Reform Legislation; an increase of $1.4 billion in total property, plant, and equipment primarily related to the traditional electric operating companies' installation of equipment to comply with environmental standards and construction of electric generation, transmission, and distribution facilities, Southern Company Gas' infrastructure replacement programs, and Southern Power's renewable acquisitions, largely offset by the $2.8 billion write-down of the gasification portions of the Kemper County energy facility and payments of $1.7 billion received by Georgia Power under the Guarantee Settlement Agreement; an increase of $3.1 billion in long-term debt (including amounts due within one year) primarily to fund the Southern Company system's continuous construction programs and for general corporate purposes; and a decrease of $1.1 billion in total stockholder's equity primarily related to the Kemper County energy facility charges, partially offset by the issuance of additional shares of common stock. See FUTURE EARNINGS POTENTIAL – " Income Tax Matters – Federal Tax Reform Legislation " and " Financing Activities " herein and Note 3 to the financial statements under " Nuclear Construction " and " Kemper County Energy Facility " for additional information.

At the end of 2017 , the market price of Southern Company's common stock was $48.09 per share (based on the closing price as reported on the New York Stock Exchange) and the book value was $23.99 per share, representing a market-to-book value ratio of 201% , compared to $49.19 , $25.00 , and 197% , respectively, at the end of 2016 .

Southern Company's consolidated ratio of common equity to total capitalization plus short-term debt was 31.5% and 33.3% at December 31, 2017 and 2016 , respectively. See Note 6 to the financial statements for additional information.

**Sources of Capital**

Southern Company intends to meet its future capital needs through operating cash flows, borrowings from financial institutions, and debt and equity issuances in the capital markets. Equity capital can be provided from any combination of the Company's stock plans, private placements, or public offerings. The amount and timing of additional equity and debt issuances in 2018 , as well as in subsequent years, will be contingent on Southern Company's investment opportunities and the Southern Company system's capital requirements and will depend upon prevailing market conditions and other factors. See " Capital Requirements and Contractual Obligations " herein for additional information.

Except as described herein, the traditional electric operating companies, Southern Power, and Southern Company Gas plan to obtain the funds required for construction and other purposes from operating cash flows, external security issuances, borrowings from financial institutions, and equity contributions or loans from Southern Company. Southern Power also plans to utilize tax equity partnership contributions, as well as funds resulting from any potential sale of a 33% equity interest in a newly-formed holding company that owns substantially all of its solar assets, if completed. Southern Company Gas also plans to utilize the proceeds from the pending asset sales of two of its natural gas distribution utilities. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors. See FUTURE EARNINGS POTENTIAL – "General" herein for additional information.

In addition, in 2014, Georgia Power entered into the Loan Guarantee Agreement with the DOE, under which the proceeds of borrowings may be used to reimburse Georgia Power for Eligible Project Costs incurred in connection with its construction of Plant Vogtle Units 3 and 4. Under the Loan Guarantee Agreement, the DOE agreed to guarantee borrowings of up to $3.46 billion (not to exceed 70% of Eligible Project Costs) to be made by Georgia Power under a multi-advance credit facility (FFB Credit Facility) among Georgia Power, the DOE, and the FFB. As of December 31, 2017 , Georgia Power had borrowed $2.6 billion under the FFB Credit Facility. On July 27, 2017, Georgia Power entered into an amendment to the Loan Guarantee Agreement, which provides that further advances are conditioned upon the DOE's approval of any agreements entered into in replacement of the Vogtle 3 and 4 Agreement and satisfaction of certain other conditions.

On September 28, 2017, the DOE issued a conditional commitment to Georgia Power for up to approximately $1.67 billion of additional guaranteed loans under the Loan Guarantee Agreement. This conditional commitment expires on June 30, 2018, subject to any further extension approved by the DOE. Final approval and issuance of these additional loan guarantees by the DOE cannot be assured and are subject to the negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions. See Note 6 to the financial statements under " DOE Loan Guarantee Borrowings " for additional information regarding the Loan Guarantee Agreement, including applicable covenants, events of default, mandatory prepayment events, and additional conditions to borrowing. Also see Note 3 to the financial statements under " Nuclear Construction " for additional information regarding Plant Vogtle Units 3 and 4.

The issuance of securities by the traditional electric operating companies and Nicor Gas is generally subject to the approval of the applicable state PSC or other applicable state regulatory agency. The issuance of all securities by Mississippi Power and short-term securities by Georgia Power is generally subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, Southern Company and certain of its subsidiaries file registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the appropriate regulatory authorities, as well as the securities registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

Southern Company, each traditional electric operating company, and Southern Power generally obtain financing separately without credit support from any affiliate. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of each company are not commingled with funds of any other company in the Southern Company system.

In addition, Southern Company Gas Capital obtains external financing for Southern Company Gas and its subsidiaries, other than Nicor Gas, which obtains financing separately without credit support from any affiliates. Nicor Gas' commercial paper program supports its working capital needs as Nicor Gas is not permitted to make money pool loans to affiliates. All of the other Southern Company Gas subsidiaries benefit from Southern Company Gas Capital's commercial paper program.

See Note 6 to the financial statements under " Bank Credit Arrangements " for additional information.

As of December 31, 2017 , Southern Company's current liabilities exceeded current assets by $3.5 billion , due to $3.9 billion of long-term debt that is due within one year (comprised of approximately $1.0 billion at the parent company, $0.9 billion at Georgia Power, $1.0 billion at Mississippi Power, $0.8 billion at Southern Power, and $0.2 billion at Southern Company Gas) and $2.4 billion of notes payable (comprised of approximately $0.6 billion at the parent company, $0.2 billion at Georgia Power, $0.1 billion at Southern Power, and $1.5 billion at Southern Company Gas). To meet short-term cash needs and contingencies, the Southern Company system has substantial cash flow from operating activities and access to capital markets and financial institutions. Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas intend to utilize operating cash flows, as well as commercial paper, lines of credit, bank notes, and securities issuances, as market conditions permit, as well as, under certain circumstances for the traditional electric operating companies, Southern Power, and Southern Company Gas, equity contributions and/or loans from Southern Company to meet their short-term capital needs.

At December 31, 2017 , Southern Company and its subsidiaries had approximately $2.1 billion of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2017 were as follows:

| | Expires | | | | | | Executable Term Loans | | Expires Within One Year | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Company** | **2018** | **2019** | **2020** | **2022** | **Total** | **Unused** | **One Year** | **Two Years** | **Term Out** | **No Term Out** |
| | | | | | *(in millions)* | | | | | |
| Southern Company [(a)] | $ — | $ — | $ — | $ 2,000 | $ 2,000 | $ 1,999 | $ — | $ — | $ — | $ — |
| Alabama Power | 35 | — | 500 | 800 | 1,335 | 1,335 | — | — | — | 35 |
| Georgia Power | — | — | — | 1,750 | 1,750 | 1,732 | — | — | — | — |
| Gulf Power | 30 | 25 | 225 | — | 280 | 280 | 45 | — | 20 | 10 |
| Mississippi Power | 100 | — | — | — | 100 | 100 | — | — | — | 100 |
| Southern Power Company [(b)] | — | — | — | 750 | 750 | 728 | — | — | — | — |
| Southern Company Gas [(c)] | — | — | — | 1,900 | 1,900 | 1,890 | — | — | — | — |
| Other | 30 | — | — | — | 30 | 30 | 20 | — | 20 | 10 |
| Southern Company Consolidated | $ 195 | $ 25 | $ 725 | $ 7,200 | $ 8,145 | $ 8,094 | $ 65 | $ — | $ 40 | $ 155 |

(a) Represents the Southern Company parent entity.

(b) Does not include Southern Power's $120 million continuing letter of credit facility for standby letters of credit expiring in 2019, of which $19 million remains unused at December 31, 2017 .

(c) Southern Company Gas, as the parent entity, guarantees the obligations of Southern Company Gas Capital, which is the borrower of $1.4 billion of these arrangements. Southern Company Gas' committed credit arrangements also include $500 million for which Nicor Gas is the borrower and which is restricted for working capital needs of Nicor Gas.

See Note 6 to the financial statements under " Bank Credit Arrangements " for additional information.

In May 2017, Southern Company, Alabama Power, Georgia Power, and Southern Power Company each amended certain of their multi-year credit arrangements, which, among other things, extended the maturity dates from 2020 to 2022. Southern Company and Southern Power Company increased their borrowing ability under these arrangements to $2.0 billion from $1.25 billion and to $750 million from $600 million, respectively. Southern Company also terminated its $1.0 billion facility maturing in 2018.

Also in May 2017, Southern Company Gas Capital and Nicor Gas terminated their existing credit arrangements for $1.3 billion and $700 million, respectively, which were to mature in 2017 and 2018, and entered into a new multi-year credit arrangement with $1.4 billion and $500 million currently allocated to Southern Company Gas Capital and Nicor Gas, respectively, maturing in 2022. Pursuant to the new multi-year credit arrangement, the allocations between Southern Company Gas Capital and Nicor Gas may be adjusted. In September 2017, Alabama Power also amended its $500 million multi-year credit arrangement, which, among other things, extended the maturity date from 2018 to 2020. In November 2017, Gulf Power amended $195 million of its multi-year credit arrangements to extend the maturity dates from 2017 and 2018 to 2020 and Mississippi Power amended its one-year credit arrangements in an aggregate amount of $100 million to extend the maturity dates from 2017 to 2018.

Most of these bank credit arrangements, as well as the term loan arrangements of Southern Company, Alabama Power, Georgia Power, Mississippi Power, and Southern Power Company, contain covenants that limit debt levels and contain cross-acceleration or cross-default provisions to other indebtedness (including guarantee obligations) that are restricted only to the indebtedness of the individual company. Such cross-default provisions to other indebtedness would trigger an event of default if the applicable borrower defaulted on indebtedness or guarantee obligations over a specified threshold. Such cross-acceleration provisions to other indebtedness would trigger an event of default if the applicable borrower defaulted on indebtedness, the payment of which was then accelerated. At December 31, 2017 , Southern Company, the traditional electric operating companies, Southern Power Company, Southern Company Gas, and Nicor Gas were in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings.

Subject to applicable market conditions, Southern Company and its subsidiaries expect to renew or replace their bank credit arrangements as needed, prior to expiration. In connection therewith, Southern Company and its subsidiaries may extend the maturity dates and/or increase or decrease the lending commitments thereunder.

A portion of the unused credit with banks is allocated to provide liquidity support to the revenue bonds of the traditional electric operating companies and the commercial paper programs of Southern Company, the traditional electric operating companies, Southern Power Company, Southern Company Gas, and Nicor Gas. The amount of variable rate revenue bonds of the traditional electric operating companies outstanding requiring liquidity support as of December 31, 2017 was approximately $1.5 billion as compared to $1.9 billion at December 31, 2016 . In addition, at December 31, 2017 , the traditional electric operating companies had approximately $714 million of revenue bonds outstanding that were required to be remarketed within the next 12 months. Subsequent to December 31, 2017, $50 million of these revenue bonds of Mississippi Power which were in a long-term interest rate mode were remarketed in an index rate mode.

At December 31, 2017, Pivotal Utility Holdings, Inc., a subsidiary of Southern Company Gas, had $200 million of gas facility revenue bonds outstanding. The Elizabethtown Gas asset sale agreement requires that bonds representing $180 million of the total that are currently eligible for redemption at par be redeemed on or prior to consummation of the sale. See FUTURE EARNINGS POTENTIAL – "General" herein and Note 6 to the financial statements under "Gas Facility Revenue Bonds" for additional information.

Southern Company, the traditional electric operating companies (other than Mississippi Power), Southern Power Company, Southern Company Gas, and Nicor Gas make short-term borrowings primarily through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above. Short-term borrowings are included in notes payable in the balance sheets.

**MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)**
**Southern Company and Subsidiary Companies 2017 Annual Report**

Details of short-term borrowings were as follows:

| | Short-term Debt at the End of the Period | | Short-term Debt During the Period (*) | | |
|---|---|---|---|---|---|
| | Amount Outstanding | Weighted Average Interest Rate | Average Amount Outstanding | Weighted Average Interest Rate | Maximum Amount Outstanding |
| | *(in millions)* | | *(in millions)* | | *(in millions)* |
| **December 31, 2017:** | | | | | |
| Commercial paper | **$ 1,832** | **1.8%** | **$ 2,117** | **1.3%** | **$ 2,946** |
| Short-term bank debt | **607** | **2.3%** | **555** | **2.1%** | **1,020** |
| Total | **$ 2,439** | **1.9%** | **$ 2,672** | **1.5%** | |
| **December 31, 2016:** | | | | | |
| Commercial paper | $ 1,909 | 1.1% | $ 976 | 0.8% | $ 1,970 |
| Short-term bank debt | 123 | 1.7% | 176 | 1.7% | 500 |
| Total | $ 2,032 | 1.1% | $ 1,152 | 1.1% | |
| **December 31, 2015:** | | | | | |
| Commercial paper | $ 740 | 0.7% | $ 842 | 0.4% | $ 1,563 |
| Short-term bank debt | 500 | 1.4% | 444 | 1.1% | 795 |
| Total | $ 1,240 | 0.9% | $ 1,286 | 0.5% | |

(*) Average and maximum amounts are based upon daily balances during the 12-month periods ended December 31, 2017 , 2016 , and 2015 .

In addition to the short-term borrowings of Southern Power Company included in the table above, at December 31, 2016 and 2015, Southern Power Company subsidiaries had credit agreements (Project Credit Facilities) assumed with the acquisition of certain solar facilities, which were non-recourse to Southern Power Company, the proceeds of which were used to finance project costs related to such solar facilities. The Project Credit Facilities were fully repaid in January 2017. For the year ended December 31, 2016, the Project Credit Facilities had a maximum amount outstanding of $828 million and an average amount outstanding of $566 million at a weighted average interest rate of 2.1% and had total amounts outstanding of $209 million at a weighted average interest rate of 2.1% at December 31, 2016. For the year ended December 31, 2015, the Project Credit Facilities had a maximum amount outstanding of $137 million and an average amount outstanding of $13 million at a weighted average interest rate of 2.0% and had total amounts outstanding of $137 million at a weighted average interest rate of 2.0% at December 31, 2015.

Furthermore, in connection with the acquisition of a solar facility in July 2016, a subsidiary of Southern Power Company assumed a $217 million construction loan, which was fully repaid in September 2016. During this period, the credit agreement had a maximum amount outstanding of $217 million and an average amount outstanding of $137 million at a weighted average interest rate of 2.2%.

The Company believes the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, bank term loans, and operating cash flows.

**Financing Activities**

During 2017 , Southern Company issued approximately 14.6 million shares of common stock primarily through employee equity compensation plans and received proceeds of approximately $659 million .

In addition, during the second and third quarters of 2017 , Southern Company issued a total of approximately 2.7 million shares of common stock through at-the-market issuances pursuant to sales agency agreements related to Southern Company's continuous equity offering program and received cash proceeds of approximately $134 million, net of $1.1 million in fees and commissions.

The following table outlines the long-term debt financing activities for Southern Company and its subsidiaries for the year ended December 31, 2017:

| Company | Senior Note Issuances | Senior Note Maturities and Redemptions | Revenue Bond Issuances and Reofferings of Purchased Bonds | Revenue Bond Maturities, Redemptions, and Repurchases | Other Long-Term Debt Issuances | Other Long-Term Debt Redemptions and Maturities [(a)] |
|---|---|---|---|---|---|---|
| | *(in millions)* | | | | | |
| Southern Company [(b)] | $ 300 | $ 400 | $ — | $ — | $ 950 | $ 400 |
| Alabama Power | 1,100 | 525 | — | 36 | — | — |
| Georgia Power | 1,350 | 450 | 65 | 65 | 370 | 17 |
| Gulf Power | 300 | 85 | — | — | 6 | — |
| Mississippi Power | — | 35 | — | — | 40 | 962 |
| Southern Power | 525 | 500 | — | — | 43 | 18 |
| Southern Company Gas [(c)] | 450 | — | — | — | 400 | 22 |
| Other | — | — | — | — | — | 15 |
| Elimination [(d)] | — | — | — | — | (40) | (602) |
| Southern Company Consolidated | $ 4,025 | $ 1,995 | $ 65 | $ 101 | $ 1,769 | $ 832 |

(a) Includes reductions in capital lease obligations resulting from cash payments under capital leases.

(b) Represents the Southern Company parent entity.

(c) The senior notes were issued by Southern Company Gas Capital and guaranteed by the Southern Company Gas parent entity. Other long-term debt issued represents first mortgage bonds issued by Nicor Gas.

(d) Includes intercompany loans from Southern Company to Mississippi Power and reductions in affiliate capital lease obligations at Georgia Power. These transactions are eliminated in Southern Company's Consolidated Financial Statements.

Except as otherwise described herein, Southern Company and its subsidiaries used the proceeds of debt issuances for their redemptions and maturities shown in the table above, to repay short-term indebtedness, and for general corporate purposes, including working capital and, for the subsidiaries, their continuous construction programs.

In March 2017, Southern Company repaid at maturity a $400 million 18-month floating rate bank loan.

In June 2017, Southern Company issued $500 million aggregate principal amount of Series 2017A 5.325% Junior Subordinated Notes due June 21, 2057 and $300 million aggregate principal amount of Series 2017A Floating Rate Senior Notes due September 30, 2020, which bear interest at a floating rate based on three-month LIBOR.

Also in June 2017, Southern Company entered into two $100 million aggregate principal amount short-term floating rate bank term loan agreements, which mature on June 21, 2018 and June 29, 2018 and bear interest based on one-month LIBOR.

In August 2017, Southern Company borrowed $250 million pursuant to a short-term uncommitted bank credit arrangement, which bears interest at a rate agreed upon by Southern Company and the bank from time to time and is payable on no less than 30 days' demand by the bank.

Also in August 2017, Southern Company repaid at maturity $400 million aggregate principal amount of Series 2014A 1.30% Senior Notes.

In November 2017, Southern Company issued $450 million aggregate principal amount of Series 2017B 5.25% Junior Subordinated Notes due December 1, 2077.

In September 2017, Alabama Power issued 10 million shares ($250 million aggregate stated capital) of 5.00% Class A Preferred Stock, Cumulative, Par Value $1 Per Share (Stated Capital $25 Per Share). The majority of the proceeds were used in October 2017 to redeem all 2 million shares ($50 million aggregate stated capital) of Alabama Power's 6.50% Series Preference Stock, 6 million shares ($150 million aggregate stated capital) of Alabama Power's 6.45% Series Preference Stock, and 1.52 million shares ($38 million aggregate stated capital) of Alabama Power's 5.83% Class A Preferred Stock.

In June 2017, Georgia Power entered into two short-term floating rate bank loans in aggregate principal amounts of $50 million and $150 million, with maturity dates of December 1, 2017 and May 31, 2018, respectively, and one long-term floating rate bank loan of $100 million, with a maturity date of June 28, 2018, which was amended in August 2017 to extend the maturity date to October 26, 2018. These loans bear interest based on one-month LIBOR. Also in June 2017, Georgia Power borrowed $500 million pursuant to a short-term uncommitted bank credit arrangement, which bears interest at a rate agreed upon by Georgia Power and the bank from time to time and is payable on no less than 30 days' demand by the bank.

In August 2017, Georgia Power repaid its $50 million floating rate bank loan due December 1, 2017 and $250 million of the $500 million aggregate principal amount outstanding pursuant to its uncommitted bank credit arrangement. In December 2017, Georgia Power repaid the remaining $250 million aggregate principal amount outstanding pursuant to its uncommitted bank credit arrangement.

Subsequent to December 31, 2017 , Georgia Power repaid its outstanding $150 million and $100 million floating rate bank loans due May 31, 2018 and October 26, 2018, respectively.

As reflected in the table above under other long-term debt issuances, in September 2017, Georgia Power also issued $270 million aggregate principal amount of Series 2017A 5.00% Junior Subordinated Notes due October 1, 2077. The proceeds were used to redeem all 1.8 million shares ($45 million aggregate liquidation amount) of Georgia Power's 6.125% Series Class A Preferred Stock and 2.25 million shares ($225 million aggregate liquidation amount) of Georgia Power's 6.50% Series 2007A Preference Stock.

In March 2017, Gulf Power extended the maturity of its $100 million short-term floating rate bank loan bearing interest based on one-month LIBOR from April 2017 to October 2017 and subsequently repaid the loan in May 2017.

A portion of the proceeds of Gulf Power's senior note issuances was used in June 2017 to redeem 550,000 shares ($55 million aggregate liquidation amount) of Gulf Power's 6.00% Series Preference Stock, 450,000 shares ($45 million aggregate liquidation amount) of Gulf Power's Series 2007A 6.45% Preference Stock, and 500,000 shares ($50 million aggregate liquidation amount) of Gulf Power's Series 2013A 5.60% Preference Stock.

In June 2017, Mississippi Power prepaid $300 million of the outstanding principal amount under its $1.2 billion unsecured term loan, which matures on March 30, 2018.

In September 2017, Southern Power amended its $60 million aggregate principal amount floating rate term loan to, among other things, increase the aggregate principal amount to $100 million and extend the maturity date from September 2017 to October 2018.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Southern Company and its subsidiaries plan to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

**Credit Rating Risk**

At December 31, 2017 , Southern Company and its subsidiaries did not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change of certain subsidiaries to BBB and/or Baa2 or below. These contracts are for physical electricity and natural gas purchases and sales, fuel purchases, fuel transportation and storage, energy price risk management, transmission, interest rate management, and construction of new generation at Plant Vogtle Units 3 and 4.

The maximum potential collateral requirements under these contracts at December 31, 2017 were as follows:

| Credit Ratings | Maximum Potential Collateral Requirements | |
|---|---|---|
| | *(in millions)* | |
| At BBB and/or Baa2 | $ | 40 |
| At BBB- and/or Baa3 | $ | 665 |
| At BB+ and/or Ba1 (*) | $ | 2,390 |

(*) Any additional credit rating downgrades at or below BB- and/or Ba3 could increase collateral requirements up to an additional $38 million.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact the ability of Southern Company and its subsidiaries to access capital markets and would be likely to impact the cost at which they do so.

On March 1, 2017, Moody's downgraded the senior unsecured debt rating of Mississippi Power to Ba1 from Baa3.

On March 20, 2017, Moody's revised its rating outlook for Georgia Power from stable to negative.

On March 24, 2017, S&P revised its consolidated credit rating outlook for Southern Company and its subsidiaries (including the traditional electric operating companies, Southern Power, Southern Company Gas, Southern Company Gas Capital, and Nicor Gas) from stable to negative.

On March 30, 2017, Fitch Ratings, Inc. placed the ratings of Southern Company, Georgia Power, and Mississippi Power on rating watch negative.

On June 22, 2017, Moody's placed the ratings of Mississippi Power on review for downgrade. On September 21, 2017, Moody's revised its rating outlook for Mississippi Power from under review to stable.

On January 19, 2018, Moody's revised its rating outlooks for Southern Company and Alabama Power from stable to negative.

While it is unclear how the credit rating agencies, the FERC, and relevant state regulatory bodies may respond to the Tax Reform Legislation, certain financial metrics, such as the funds from operations to debt percentage, used by the credit rating agencies to assess Southern Company and its subsidiaries may be negatively impacted. Absent actions by Southern Company and its subsidiaries to mitigate the resulting impacts, which, among other alternatives, could include adjusting capital structure and/or monetizing regulatory assets, the credit ratings of Southern Company and certain of its subsidiaries could be negatively affected. See Note 3 to the financial statements for additional information related to state PSC or other regulatory agency actions related to the Tax Reform Legislation.

**Market Price Risk**

The Southern Company system is exposed to market risks, including commodity price risk, interest rate risk, weather risk, and occasionally foreign currency exchange rate risk. To manage the volatility attributable to these exposures, the applicable company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the applicable company's policies in areas such as counterparty exposure and risk management practices. Southern Company Gas' wholesale gas operations use various contracts in its commercial activities that generally meet the definition of derivatives. For the traditional electric operating companies, Southern Power, and Southern Company Gas' other businesses, each company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to a change in interest rates, Southern Company and certain of its subsidiaries enter into derivatives that have been designated as hedges. Derivatives that have been designated as hedges outstanding at December 31, 2017 have a notional amount of $3.7 billion and are intended to mitigate interest rate volatility related to existing fixed and floating rate obligations. The weighted average interest rate on $6.3 billion of long-term variable interest rate exposure at December 31, 2017 was 2.43%. If Southern Company sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would affect annualized interest expense by approximately $63 million at December 31, 2017 . See Note 1 to the financial statements under " Financial Instruments " and Note 11 to the financial statements for additional information.

Southern Power Company had foreign currency denominated debt of €1.1 billion at December 31, 2017 . Southern Power Company has mitigated its exposure to foreign currency exchange rate risk through the use of foreign currency swaps converting all interest and principal payments to fixed-rate U.S. dollars.

Due to cost-based rate regulation and other various cost recovery mechanisms, the traditional electric operating companies and natural gas distribution utilities continue to have limited exposure to market volatility in interest rates, foreign currency exchange rates, commodity fuel prices, and prices of electricity. In addition, Southern Power's exposure to market volatility in commodity fuel prices and prices of electricity is limited because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of uncontracted generating capacity. To mitigate residual risks relative to movements in electricity prices, the traditional electric operating companies and Southern Power may enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases; however, a significant portion of contracts are priced at market. The traditional electric operating companies and certain of the natural gas distribution utilities manage fuel-hedging programs implemented per the guidelines of their respective state PSCs or other applicable state regulatory agencies. Southern Company had no material change in market risk exposure for the year ended December 31, 2017 when compared to the year ended December 31, 2016 .

The changes in fair value of energy-related derivative contracts are substantially attributable to both the volume and the price of natural gas. For the years ended December 31, the changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, were as follows:

| | **2017 Changes** | 2016 Changes |
|---|---|---|
| | Fair Value | |
| | *(in millions)* | |
| Contracts outstanding at the beginning of the period, assets (liabilities), net | **$ 41** | $ (213) |
| Acquisitions | **—** | (54) |
| Contracts realized or settled | **(8)** | 141 |
| Current period changes [(a)] | **(196)** | 171 |
| Contracts outstanding at the end of the period, assets (liabilities), net [(b)] | **$ (163)** | $ 45 |

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

(b) Excludes premium and intrinsic value associated with weather derivatives of $11 million at December 31, 2017 and includes premium and intrinsic value associated with weather derivatives of $4 million at December 31, 2016 .

The net hedge volumes of energy-related derivative contracts were 621 million mmBtu and 500 million mmBtu for the years ended December 31, 2017 and 2016 , respectively.

For the traditional electric operating companies and Southern Power, the weighted average swap contract cost above or (below) market prices was approximately $0.15 per mmBtu as of December 31, 2017 and $(0.05) per mmBtu as of December 31, 2016 . The majority of the natural gas hedge gains and losses are recovered through the traditional electric operating companies' fuel cost recovery clauses.

At December 31, 2017 and 2016 , substantially all of the Southern Company system's energy-related derivative contracts were designated as regulatory hedges and were related to the applicable company's fuel-hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the energy cost recovery clause. Certain other gains and losses on energy-related derivatives, designated as cash flow hedges, are initially deferred in OCI before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

The Southern Company system uses exchange-traded market-observable contracts, which are categorized as Level 1 of the fair value hierarchy, and over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2 of the fair value hierarchy. See Note 10 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts at December 31, 2017 were as follows:

| | Fair Value Measurements December 31, 2017 | | | |
|---|---|---|---|---|
| | Total Fair Value | Maturity | | |
| | | Year 1 | Years 2&3 | Years 4&5 |
| | *(in millions)* | | | |
| Level 1 | $ (148) | $ (71) | $ (59) | $ (18) |
| Level 2 | (15) | (30) | 13 | 2 |
| Level 3 | — | — | — | — |
| Fair value of contracts outstanding at end of period | $ (163) | $ (101) | $ (46) | $ (16) |

The Southern Company system is exposed to market price risk in the event of nonperformance by counterparties to energy-related and interest rate derivative contracts. The Southern Company system only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P, or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Southern Company system does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under " Financial Instruments " and Note 11 to the financial statements.

With the exception of Southern Company Gas' subsidiary, Atlanta Gas Light, and the Southern Company Gas wholesale gas services business, the Southern Company system is not exposed to concentrations of credit risk. Concentration of credit risk occurs at Atlanta Gas Light for amounts billed for services and other costs to its customers, which consist of 15 natural gas marketers in Georgia responsible for the retail sale of natural gas to end-use customers in Georgia. For 2017 , the four largest natural gas marketers based on customer count accounted for 19% of Southern Company Gas' adjusted operating margin. Southern Company Gas' wholesale gas services business has a concentration of credit risk for services it provides to its counterparties as measured by its 30-day receivable exposure plus forward exposure. At December 31, 2017 , Southern Company Gas' wholesale gas services business' top 20 counterparties represented approximately 48% , or $203 million , of its total counterparty exposure and had a weighted average S&P equivalent credit rating of A-, all of which is consistent with the prior year.

Southern Company performs periodic reviews of its leveraged lease transactions, both domestic and international, and the creditworthiness of the lessees, including a review of the value of the underlying leased assets and the credit ratings of the lessees. Southern Company's domestic lease transactions generally do not have any credit enhancement mechanisms; however, the lessees in its international lease transactions have pledged various deposits as additional security to secure the obligations. The lessees in the Company's international lease transactions are also required to provide additional collateral in the event of a credit downgrade below a certain level.

**Capital Requirements and Contractual Obligations**

The Southern Company system's construction program is currently estimated to total approximately $9.4 billion for 2018 , $9.3 billion for 2019 , $8.4 billion for 2020 , $7.0 billion for 2021 , and $6.9 billion for 2022 . These amounts include expenditures of approximately $1.2 billion , $1.0 billion , $0.9 billion , $0.7 billion , and $0.4 billion for the construction of Plant Vogtle Units 3 and 4 in 2018 , 2019 , 2020 , 2021 , and 2022 , respectively, and an average of approximately $1.3 billion per year for 2018 through 2022 for Southern Power's planned expenditures for plant acquisitions and placeholder growth. These amounts also include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under LTSAs. Estimated capital expenditures to comply with environmental laws and regulations included in these amounts are $1.1 billion , $0.3 billion , $0.4 billion , $0.5 billion , and $0.5 billion for 2018 , 2019 , 2020 , 2021 , and 2022 , respectively. These estimated expenditures do not include any potential compliance costs associated with the regulation of $CO_2$ emissions from fossil fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – " Environmental Matters – Environmental Laws and Regulations " and " – Global Climate Issues " herein for additional information.

The traditional electric operating companies also anticipate costs associated with closure and monitoring of ash ponds in accordance with the CCR Rule, which are reflected in the Company's ARO liabilities. These costs, which could change as the Southern Company system continues to refine its assumptions underlying the cost estimates and evaluate the method and timing of compliance activities, are estimated to be approximately $0.3 billion , $0.3 billion , $0.4 billion , $0.5 billion , and $0.4 billion for 2018 , 2019 , 2020 , 2021 , and 2022 , respectively. See Note 1 to the financial statements under " Asset Retirement Obligations and Other Costs of Removal " for additional information.

The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental laws and regulations; the outcome of any legal challenges to the environmental rules; changes in electric generating plants, including unit retirements and replacements and adding or changing fuel sources at existing electric generating units, to meet regulatory requirements; changes in FERC rules and regulations; state regulatory agency approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. Additionally, planned expenditures for plant acquisitions may vary due to market opportunities and Southern Power's ability to execute its growth strategy. See Note 12 to the financial statements under " Southern Power " for additional information regarding Southern Power's plant acquisitions.

In addition, the construction program includes the development and construction of new electric generating facilities with designs that have not been previously constructed, which may result in revised estimates during construction. The ability to control costs and avoid cost overruns during the development, construction, and operation of new facilities is subject to a number of factors, including, but not limited to, changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction, operating, or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance. See Note 3 to the financial statements under " Nuclear Construction " for information regarding additional factors that may impact construction expenditures.

**MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)**
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As a result of NRC requirements, Alabama Power and Georgia Power have external trust funds for nuclear decommissioning costs; however, Alabama Power currently has no additional funding requirements. For additional information, see Note 1 to the financial statements under " Nuclear Decommissioning ."

In addition, as discussed in Note 2 to the financial statements, the Southern Company system provides postretirement benefits to the majority of its employees and funds trusts to the extent required by PSCs, other applicable state regulatory agencies, or the FERC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred stock dividends, leases, unrecognized tax benefits, pipeline charges, storage capacity, gas supply, asset management agreements, other purchase commitments, and trusts are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 11 to the financial statements for additional information.

**Contractual Obligations**

The Southern Company system's contractual obligations at December 31, 2017 were as follows:

| | 2018 | 2019- 2020 | 2021- 2022 | After 2022 | Total |
|---|---|---|---|---|---|
| | | | *(in millions)* | | |
| Long-term debt [(a)] — | | | | | |
| Principal | $ 3,865 | $ 6,293 | $ 5,206 | $ 32,610 | $ 47,974 |
| Interest | 1,782 | 3,286 | 2,793 | 27,535 | 35,396 |
| Preferred stock dividends of subsidiaries [(b)] | 16 | 33 | 33 | — | 82 |
| Financial derivative obligations [(c)] | 493 | 198 | 37 | 5 | 733 |
| Operating leases [(d)] | 149 | 232 | 178 | 968 | 1,527 |
| Capital leases [(d)] | 39 | 43 | 20 | 232 | 334 |
| Unrecognized tax benefits [(e)] | 18 | — | — | — | 18 |
| Pipeline charges, storage capacity, and gas supply [(f)] | 813 | 968 | 714 | 2,294 | 4,789 |
| Asset management agreements [(g)] | 9 | 6 | — | — | 15 |
| Purchase commitments — | | | | | |
| Capital [(h)] | 9,016 | 16,905 | 12,749 | — | 38,670 |
| Fuel [(i)] | 3,156 | 3,573 | 1,927 | 5,588 | 14,244 |
| Purchased power [(j)] | 424 | 884 | 886 | 3,716 | 5,910 |
| Other [(k)] | 407 | 713 | 434 | 2,745 | 4,299 |
| Trusts — | | | | | |
| Nuclear decommissioning [(l)] | 5 | 11 | 11 | 94 | 121 |
| Pension and other postretirement benefit plans [(m)] | 137 | 275 | — | — | 412 |
| Total | $ 20,329 | $ 33,420 | $ 24,988 | $ 75,787 | $ 154,524 |

(a) All amounts are reflected based on final maturity dates except for amounts related to FFB borrowings and certain revenue bonds. As it relates to the FFB borrowings, the final maturity date is February 20, 2044; however, principal amortization is reflected beginning in 2020. See Note 6 to the financial statements under " DOE Loan Guarantee Borrowings " and " Securities Due Within One Year " for additional information. Southern Company and its subsidiaries plan to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of December 31, 2017 , as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).

(b) Represents preferred stock of subsidiaries. Preferred stock does not mature; therefore, amounts are provided for the next five years only.

(c) See Notes 1 and 11 to the financial statements.

(d) Excludes PPAs that are accounted for as leases and included in "Purchased power."

(e) See Note 5 to the financial statements under " Unrecognized Tax Benefits " for additional information.

(f) Includes charges recoverable through a natural gas cost recovery mechanism, or alternatively billed to marketers selling retail natural gas, and demand charges associated with Southern Company Gas' wholesale gas services. The gas supply balance includes amounts for gas commodity purchase commitments associated with Southern Company Gas' gas marketing services of 35 million mmBtu at floating gas prices calculated using forward natural gas prices at December 31, 2017 and valued at $101 million . Southern Company Gas provides guarantees to certain gas suppliers for certain of its subsidiaries in support of payment obligations.

(g) Represents fixed-fee minimum payments for asset management agreements associated with wholesale gas services.

(h) The Southern Company system provides estimated capital expenditures for a five-year period, including capital expenditures associated with environmental regulations. These amounts exclude contractual purchase commitments for nuclear fuel and capital expenditures covered under LTSAs which are reflected in "Fuel" and "Other," respectively. At December 31, 2017 , significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – " Environmental Matters – Environmental Laws and Regulations " herein for additional information.

(i) Primarily includes commitments to purchase coal, nuclear fuel, and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2017 .

(j) Estimated minimum long-term obligations for various PPA purchases from gas-fired, biomass, and wind-powered facilities.

(k) Includes LTSAs, contracts for the procurement of limestone, contractual environmental remediation liabilities, and operation and maintenance agreements. LTSAs include price escalation based on inflation indices.

(l) Projections of nuclear decommissioning trust fund contributions for Plant Hatch and Plant Vogtle Units 1 and 2 are based on the 2013 ARP for Georgia Power. Alabama Power also has external trust funds for nuclear decommissioning costs; however, Alabama Power currently has no additional funding requirements. See Note 1 to the financial statements under "Nuclear Decommissioning" for additional information.

(m) The Southern Company system forecasts contributions to the pension and other postretirement benefit plans over a three-year period. Southern Company anticipates no mandatory contributions to the qualified pension plans during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from corporate assets of Southern Company's subsidiaries. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from corporate assets of Southern Company's subsidiaries.

**Cautionary Statement Regarding Forward-Looking Statements**

Southern Company's 2017 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning regulated rates, the strategic goals for the wholesale business, customer and sales growth, economic conditions, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, pending or potential litigation matters, access to sources of capital, projections for the qualified pension plan s, postretirement benefit plans, and nuclear decommissioning trust fund contributions, financing activities, completion dates of construction projects, completion of announced acquisitions or dispositions, filings with state and federal regulatory authorities, impacts of the Tax Reform Legislation, federal and state income tax benefits, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including environmental laws and regulations governing air, water, land, and protection of other natural resources , and also changes in tax and other laws and regulations to which Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- the uncertainty surrounding the recently enacted Tax Reform Legislation, including implementing regulations and IRS interpretations, actions that may be taken in response by regulatory authorities, and its impact, if any, on the credit ratings of Southern Company and its subsidiaries;
- current and future litigation or regulatory investigations, proceedings, or inquiries ;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate;
- variations in demand for electricity and natural gas, including those relating to weather, the general economy, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of natural gas and other fuels;
- limits on pipeline capacity;
- transmission constraints;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development , construction, and operation of facilities, which include the development and construction of generating facilities with designs that have not been previously constructed, including changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor , contractor or supplier delay, non-performance under construction, operating, or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance ;
- the ability to construct facilities in accordance with the requirements of permits and licenses (including satisfaction of NRC requirements), to satisfy any environmental performance standards and the requirements of tax credits and other incentives , and to integrate facilities into the Southern Company system upon completion of construction;
- investment performance of the Southern Company system's employee and retiree benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- ongoing renewable energy partnerships and development agreements;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- the ability to successfully operate the electric utilities' generating, transmission, and distribution facilities and Southern Company Gas' natural gas distribution and storage facilities and the successful performance of necessary corporate functions ;

- legal proceedings and regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions;
- litigation related to the Kemper County energy facility;
- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, and financial risks;
- the inherent risks involved in transporting and storing natural gas;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, including the proposed disposition by a wholly-owned subsidiary of Southern Company Gas of Elizabethtown Gas and Elkton Gas and the potential sale of a 33% equity interest in substantially all of Southern Power's solar assets, which cannot be assured to be completed or beneficial to Southern Company or its subsidiaries;
- the possibility that the anticipated benefits from the Merger cannot be fully realized or may take longer to realize than expected and the possibility that costs related to the integration of Southern Company and Southern Company Gas will be greater than expected;
- the ability of counterparties of Southern Company and its subsidiaries to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Southern Company system's business resulting from cyber intrusion or physical attack and the threat of physical attacks;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in Southern Company's and any of its subsidiaries' credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on foreign currency exchange rates, counterparty performance, and the economy in general , as well as potential impacts on the benefits of the DOE loan guarantees;
- the ability of Southern Company's electric utilities to obtain additional generating capacity (or sell excess generating capacity) at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Southern Company system's business resulting from incidents affecting the U.S. electric grid , natural gas pipeline infrastructure , or operation of generating or storage resources;
- impairments of goodwill or long-lived assets;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports filed by Southern Company from time to time with the SEC.

**Southern Company expressly disclaims any obligation to update any forward-looking statements.**

**CONSOLIDATED STATEMENTS OF INCOME**
**For the Years Ended December 31, 2017 , 2016 , and 2015**
**Southern Company and Subsidiary Companies 2017 Annual Report**

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| **Operating Revenues:** | | | |
| Retail electric revenues | **$ 15,330** | $ 15,234 | $ 14,987 |
| Wholesale electric revenues | **2,426** | 1,926 | 1,798 |
| Other electric revenues | **681** | 698 | 657 |
| Natural gas revenues | **3,791** | 1,596 | — |
| Other revenues | **803** | 442 | 47 |
| Total operating revenues | **23,031** | 19,896 | 17,489 |
| **Operating Expenses:** | | | |
| Fuel | **4,400** | 4,361 | 4,750 |
| Purchased power | **863** | 750 | 645 |
| Cost of natural gas | **1,601** | 613 | — |
| Cost of other sales | **513** | 260 | — |
| Other operations and maintenance | **5,481** | 5,240 | 4,416 |
| Depreciation and amortization | **3,010** | 2,502 | 2,034 |
| Taxes other than income taxes | **1,250** | 1,113 | 997 |
| Estimated loss on Kemper IGCC | **3,362** | 428 | 365 |
| Total operating expenses | **20,480** | 15,267 | 13,207 |
| **Operating Income** | **2,551** | 4,629 | 4,282 |
| **Other Income and (Expense):** | | | |
| Allowance for equity funds used during construction | **160** | 202 | 226 |
| Earnings from equity method investments | **106** | 59 | — |
| Interest expense, net of amounts capitalized | **(1,694)** | (1,317) | (840) |
| Other income (expense), net | **(55)** | (93) | (39) |
| Total other income and (expense) | **(1,483)** | (1,149) | (653) |
| **Earnings Before Income Taxes** | **1,068** | 3,480 | 3,629 |
| Income taxes | **142** | 951 | 1,194 |
| **Consolidated Net Income** | **926** | 2,529 | 2,435 |
| Less: | | | |
| Dividends on preferred and preference stock of subsidiaries | **38** | 45 | 54 |
| Net income attributable to noncontrolling interests | **46** | 36 | 14 |
| **Consolidated Net Income Attributable to Southern Company** | **$ 842** | $ 2,448 | $ 2,367 |
| **Common Stock Data:** | | | |
| Earnings per share — | | | |
| Basic | **$ 0.84** | $ 2.57 | $ 2.60 |
| Diluted | **0.84** | 2.55 | 2.59 |
| Average number of shares of common stock outstanding — (in millions) | | | |
| Basic | **1,000** | 951 | 910 |
| Diluted | **1,008** | 958 | 914 |

The accompanying notes are an integral part of these consolidated financial statements.

**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**
**For the Years Ended December 31, 2017 , 2016 , and 2015**
**Southern Company and Subsidiary Companies 2017 Annual Report**

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| **Consolidated Net Income** | **$ 926** | $ 2,529 | $ 2,435 |
| Other comprehensive income: | | | |
| Qualifying hedges: | | | |
| Changes in fair value, net of tax of $34, $(84), and $(8), respectively | **57** | (136) | (13) |
| Reclassification adjustment for amounts included in net income, net of tax of $(37), $43, and $4, respectively | **(60)** | 69 | 6 |
| Pension and other postretirement benefit plans: | | | |
| Benefit plan net gain (loss), net of tax of $6, $10, and $(1), respectively | **17** | 13 | (2) |
| Reclassification adjustment for amounts included in net income, net of tax of $(6), $3, and $4, respectively | **(23)** | 4 | 7 |
| **Total other comprehensive income (loss)** | **(9)** | (50) | (2) |
| Less: | | | |
| Dividends on preferred and preference stock of subsidiaries | **38** | 45 | 54 |
| Comprehensive income attributable to noncontrolling interests | **46** | 36 | 14 |
| **Consolidated Comprehensive Income Attributable to Southern Company** | **$ 833** | $ 2,398 | $ 2,365 |

The accompanying notes are an integral part of these consolidated financial statements.

**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**For the Years Ended December 31, 2017 , 2016 , and 2015**
**Southern Company and Subsidiary Companies 2017 Annual Report**

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| **Operating Activities:** | | | |
| Consolidated net income | $ **926** | $ 2,529 | $ 2,435 |
| Adjustments to reconcile consolidated net income to net cash provided from operating activities — | | | |
| Depreciation and amortization, total | **3,457** | 2,923 | 2,395 |
| Deferred income taxes | **166** | (127) | 1,404 |
| Collateral deposits | **(4)** | (102) | — |
| Allowance for equity funds used during construction | **(160)** | (202) | (226) |
| Pension and postretirement funding | **(2)** | (1,029) | (7) |
| Settlement of asset retirement obligations | **(177)** | (171) | (37) |
| Stock based compensation expense | **109** | 121 | 99 |
| Hedge settlements | **6** | (233) | (17) |
| Estimated loss on Kemper IGCC | **3,179** | 428 | 365 |
| Income taxes receivable, non-current | **(47)** | (122) | (413) |
| Other, net | **(109)** | (99) | 49 |
| Changes in certain current assets and liabilities — | | | |
| -Receivables | **(199)** | (544) | 243 |
| -Fossil fuel for generation | **36** | 178 | 61 |
| -Natural gas for sale | **36** | (226) | — |
| -Other current assets | **(143)** | (206) | (152) |
| -Accounts payable | **(280)** | 301 | (353) |
| -Accrued taxes | **(142)** | 1,456 | 352 |
| -Retail fuel cost over recovery | **(212)** | (231) | 289 |
| -Mirror CWIP | **—** | — | (271) |
| -Other current liabilities | **(45)** | 250 | 58 |
| Net cash provided from operating activities | **6,395** | 4,894 | 6,274 |
| **Investing Activities:** | | | |
| Business acquisitions, net of cash acquired | **(1,070)** | (10,689) | (1,719) |
| Property additions | **(7,423)** | (7,310) | (5,674) |
| Proceeds pursuant to the Toshiba Guarantee, net of joint owner portion | **1,682** | — | — |
| Investment in restricted cash | **(17)** | (733) | (160) |
| Distribution of restricted cash | **34** | 742 | 154 |
| Nuclear decommissioning trust fund purchases | **(811)** | (1,160) | (1,424) |
| Nuclear decommissioning trust fund sales | **805** | 1,154 | 1,418 |
| Cost of removal, net of salvage | **(313)** | (245) | (167) |
| Change in construction payables, net | **259** | (121) | 402 |
| Investment in unconsolidated subsidiaries | **(152)** | (1,444) | — |
| Payments pursuant to LTSAs | **(227)** | (134) | (197) |
| Other investing activities | **42** | (108) | 87 |
| Net cash used for investing activities | **(7,191)** | (20,048) | (7,280) |
| **Financing Activities:** | | | |
| Increase (decrease) in notes payable, net | **(401)** | 1,228 | 73 |
| Proceeds — | | | |
| Long-term debt | **5,858** | 16,368 | 7,029 |
| Common stock | **793** | 3,758 | 256 |
| Preferred stock | **250** | — | — |
| Short-term borrowings | **1,259** | — | 755 |
| Redemptions and repurchases — | | | |
| Long-term debt | **(2,930)** | (3,145) | (3,604) |

| | | | | | | |
|---|---|---|---|---|---|---|
| Common stock | | **—** | | — | | (115) |
| Interest-bearing refundable deposits | | **—** | | — | | (275) |
| Preferred and preference stock | | **(658)** | | — | | (412) |
| Short-term borrowings | | **(659)** | | (478) | | (255) |
| Distributions to noncontrolling interests | | **(119)** | | (72) | | (18) |
| Capital contributions from noncontrolling interests | | **80** | | 682 | | 341 |
| Payment of common stock dividends | | **(2,300)** | | (2,104) | | (1,959) |
| Other financing activities | | **(222)** | | (512) | | (116) |
| Net cash provided from financing activities | | **951** | | 15,725 | | 1,700 |
| **Net Change in Cash and Cash Equivalents** | | **155** | | 571 | | 694 |
| **Cash and Cash Equivalents at Beginning of Year** | | **1,975** | | 1,404 | | 710 |
| **Cash and Cash Equivalents at End of Year** | **$** | **2,130** | $ | 1,975 | $ | 1,404 |

The accompanying notes are an integral part of these consolidated financial statements.

**CONSOLIDATED BALANCE SHEETS**
**At December 31, 2017 and 2016**
**Southern Company and Subsidiary Companies 2017 Annual Report**

| **Assets** | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Current Assets:** | | |
| Cash and cash equivalents | **$ 2,130** | $ 1,975 |
| Receivables — | | |
| Customer accounts receivable | **1,806** | 1,583 |
| Energy marketing receivable | **607** | 623 |
| Unbilled revenues | **810** | 706 |
| Under recovered fuel clause revenues | **171** | — |
| Income taxes receivable, current | **63** | 544 |
| Other accounts and notes receivable | **635** | 377 |
| Accumulated provision for uncollectible accounts | **(44)** | (43) |
| Materials and supplies | **1,438** | 1,462 |
| Fossil fuel for generation | **594** | 689 |
| Natural gas for sale | **595** | 631 |
| Prepaid expenses | **452** | 364 |
| Other regulatory assets, current | **604** | 581 |
| Other current assets | **211** | 230 |
| Total current assets | **10,072** | 9,722 |
| **Property, Plant, and Equipment:** | | |
| In service | **103,542** | 98,416 |
| Less: Accumulated depreciation | **31,457** | 29,852 |
| Plant in service, net of depreciation | **72,085** | 68,564 |
| Nuclear fuel, at amortized cost | **883** | 905 |
| Construction work in progress | **6,904** | 8,977 |
| Total property, plant, and equipment | **79,872** | 78,446 |
| **Other Property and Investments:** | | |
| Goodwill | **6,268** | 6,251 |
| Equity investments in unconsolidated subsidiaries | **1,513** | 1,549 |
| Other intangible assets, net of amortization of $186 and $62 at December 31, 2017 and December 31, 2016, respectively | **873** | 970 |
| Nuclear decommissioning trusts, at fair value | **1,832** | 1,606 |
| Leveraged leases | **775** | 774 |
| Miscellaneous property and investments | **249** | 270 |
| Total other property and investments | **11,510** | 11,420 |
| **Deferred Charges and Other Assets:** | | |
| Deferred charges related to income taxes | **825** | 1,629 |
| Unamortized loss on reacquired debt | **206** | 223 |
| Other regulatory assets, deferred | **6,943** | 6,851 |
| Other deferred charges and assets | **1,577** | 1,406 |
| Total deferred charges and other assets | **9,551** | 10,109 |
| **Total Assets** | **$ 111,005** | $ 109,697 |

The accompanying notes are an integral part of these consolidated financial statements.

**CONSOLIDATED BALANCE SHEETS**
**At December 31, 2017 and 2016**
**Southern Company and Subsidiary Companies 2017 Annual Report**

| **Liabilities and Stockholders' Equity** | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Current Liabilities:** | | |
| Securities due within one year | **$ 3,892** | $ 2,587 |
| Notes payable | **2,439** | 2,241 |
| Energy marketing trade payables | **546** | 597 |
| Accounts payable | **2,530** | 2,228 |
| Customer deposits | **542** | 558 |
| Accrued taxes — | | |
| Accrued income taxes | **6** | 193 |
| Unrecognized tax benefits | **18** | 385 |
| Other accrued taxes | **613** | 667 |
| Accrued interest | **488** | 518 |
| Accrued compensation | **959** | 915 |
| Asset retirement obligations, current | **351** | 378 |
| Acquisitions payable | **5** | 489 |
| Other regulatory liabilities, current | **337** | 236 |
| Other current liabilities | **868** | 925 |
| Total current liabilities | **13,594** | 12,917 |
| **Long-Term Debt** ( See accompanying statements ) | **44,462** | 42,629 |
| **Deferred Credits and Other Liabilities:** | | |
| Accumulated deferred income taxes | **6,842** | 14,092 |
| Deferred credits related to income taxes | **7,256** | 219 |
| Accumulated deferred ITCs | **2,267** | 2,228 |
| Employee benefit obligations | **2,256** | 2,299 |
| Asset retirement obligations, deferred | **4,473** | 4,136 |
| Accrued environmental remediation | **389** | 397 |
| Other cost of removal obligations | **2,684** | 2,748 |
| Other regulatory liabilities, deferred | **239** | 258 |
| Other deferred credits and liabilities | **691** | 880 |
| Total deferred credits and other liabilities | **27,097** | 27,257 |
| **Total Liabilities** | **85,153** | 82,803 |
| **Redeemable Preferred Stock of Subsidiaries** ( See accompanying statements ) | **324** | 118 |
| **Redeemable Noncontrolling Interests** (See accompanying statements) | **—** | 164 |
| **Total Stockholders' Equity** ( See accompanying statements ) | **25,528** | 26,612 |
| **Total Liabilities and Stockholders' Equity** | **$ 111,005** | $ 109,697 |
| **Commitments and Contingent Matters** ( See notes ) | | |

The accompanying notes are an integral part of these consolidated financial statements.

**CONSOLIDATED STATEMENTS OF CAPITALIZATION**
**At December 31, 2017 and 2016**
**Southern Company and Subsidiary Companies 2017 Annual Report**

| | | 2017 | 2016 | 2017 | 2016 |
|---|---|---|---|---|---|
| | | | *(in millions)* | | *(percent of total)* |
| **Long-Term Debt:** | | | | | |
| Long-term debt payable to affiliated trusts — | | | | | |
| Variable rate (4.44% at 12/31/17) due 2042 | | **$ 206** | $ 206 | | |
| Long-term senior notes and debt — | | | | | |
| Maturity | Interest Rates | | | | |
| 2017 | 1.30% to 7.20% | — | 2,019 | | |
| 2018 | 1.50% to 5.40% | **2,402** | 2,403 | | |
| 2019 | 1.85% to 5.55% | **3,074** | 3,076 | | |
| 2020 | 2.00% to 4.75% | **2,273** | 1,326 | | |
| 2021 | 2.35% to 9.10% | **2,643** | 2,655 | | |
| 2022 | 1.00% to 8.70% | **2,016** | 1,378 | | |
| 2023 through 2047 | 1.85% to 7.30% | **22,142** | 20,369 | | |
| Variable rates (1.82% to 3.75% at 1/1/17) due 2017 | | — | 461 | | |
| Variable rates (2.29% to 3.05% at 12/31/17) due 2018 | | **1,420** | 1,520 | | |
| Variable rates (2.04% to 2.18% at 12/31/17) due 2020 | | **825** | — | | |
| Variable rates (2.55% to 2.79% at 12/31/17) due 2021 | | **25** | 25 | | |
| Variable rate (3.75% at 1/1/17) due 2032 to 2036 | | — | 15 | | |
| Total long-term senior notes and debt | | **36,820** | 35,247 | | |
| Other long-term debt — | | | | | |
| Pollution control revenue bonds — | | | | | |
| Maturity | Interest Rates | | | | |
| 2019 | 4.55% | **25** | 25 | | |
| 2022 | 2.10% to 2.35% | **90** | 90 | | |
| 2023 through 2049 | 1.15% to 5.15% | **1,379** | 1,339 | | |
| Variable rates (2.45% to 2.50% at 12/31/17) due 2018 | | **40** | 76 | | |
| Variable rates (1.86% to 1.87% at 12/31/17) due 2021 | | **65** | 65 | | |
| Variable rates (1.83% to 1.84% at 12/31/17) due 2022 | | **17** | 17 | | |
| Variable rates (1.59% to 1.88% at 12/31/17) due 2024 to 2053 | | **1,680** | 1,721 | | |
| Plant Daniel revenue bonds (7.13%) due 2021 | | **270** | 270 | | |
| FFB loans — | | | | | |
| 2.57% to 3.86% due 2020 | | **44** | 44 | | |
| 2.57% to 3.86% due 2021 | | **44** | 44 | | |
| 2.57% to 3.86% due 2022 | | **44** | 44 | | |
| 2.57% to 3.86% due 2023 to 2044 | | **2,493** | 2,493 | | |
| First mortgage bonds — | | | | | |
| 4.70% due 2019 | | **50** | 50 | | |
| 2.66% to 6.58% due 2023 to 2057 | | **975** | 575 | | |
| Gas facility revenue bonds — | | | | | |
| Variable rate (1.71% at 12/31/17) due 2022 | | **47** | 47 | | |
| Variable rate (1.71% at 12/31/17) due 2024 to 2033 | | **154** | 154 | | |
| Junior subordinated notes (5.00% to 6.25%) due 2057 to 2077 | | **3,570** | 2,350 | | |
| Total other long-term debt | | **10,987** | 9,404 | | |
| Unamortized fair value adjustment of long-term debt | | **525** | 578 | | |
| Capitalized lease obligations | | **204** | 136 | | |
| Unamortized debt premium | | **44** | 52 | | |
| Unamortized debt discount | | **(206)** | (194) | | |
| Unamortized debt issuance expense | | **(226)** | (213) | | |
| Total long-term debt (annual interest requirement — $1.8 billion) | | **48,354** | 45,216 | | |

| | | | | |
|---|---|---|---|---|
| Less amount due within one year | **3,892** | 2,587 | | |
| Long-term debt excluding amount due within one year | **44,462** | 42,629 | **63.2%** | 61.3% |

**CONSOLIDATED STATEMENTS OF CAPITALIZATION (continued)**
**At December 31, 2017 and 2016**
**Southern Company and Subsidiary Companies 2017 Annual Report**

| | 2017 | 2016 | 2017 | 2016 |
|---|---|---|---|---|
| | | *(in millions)* | | *(percent of total)* |
| **Redeemable Preferred Stock of Subsidiaries:** | | | | |
| Cumulative preferred stock | | | | |
| $100 par or stated value — 4.20% to 5.44% | | | | |
| Authorized — 20 million shares | | | | |
| Outstanding — 1 million shares | **324** | 81 | | |
| $1 par value — 5.83% | | | | |
| Authorized — 28 million shares | | | | |
| Outstanding — 2017: no shares | | | | |
| — 2016: 2 million shares: $25 stated value | **—** | 37 | | |
| Total redeemable preferred stock of subsidiaries (annual dividend requirement — $16 million) | **324** | 118 | **0.5** | 0.2 |
| **Redeemable Noncontrolling Interests** | **—** | 164 | **—** | 0.2 |
| **Common Stockholders' Equity:** | | | | |
| Common stock, par value $5 per share — | **5,038** | 4,952 | | |
| Authorized — 1.5 billion shares | | | | |
| Issued — 2017: 1.0 billion shares | | | | |
| — 2016: 991 million shares | | | | |
| Treasury — 2017: 0.9 million shares | | | | |
| — 2016: 0.8 million shares | | | | |
| Paid-in capital | **10,469** | 9,661 | | |
| Treasury, at cost | **(36)** | (31) | | |
| Retained earnings | **8,885** | 10,356 | | |
| Accumulated other comprehensive loss | **(189)** | (180) | | |
| Total common stockholders' equity | **24,167** | 24,758 | **34.4** | 35.6 |
| **Preferred and Preference Stock of Subsidiaries and Noncontrolling Interests:** | | | | |
| Non-cumulative preferred stock | | | | |
| $25 par value — 6.00% to 6.13% | | | | |
| Authorized — 60 million shares | | | | |
| Outstanding — 2017: no shares | | | | |
| — 2016: 2 million shares | **—** | 45 | | |
| Non-cumulative preference stock | | | | |
| $1 par value — 6.45% to 6.50% | | | | |
| Authorized — 65 million shares | | | | |
| Outstanding — 2017: no shares | **—** | 196 | | |
| — 2016: 8 million shares | | | | |
| $100 par or stated value — 5.60% to 6.50% | | | | |
| Outstanding — 2017: no shares | **—** | 368 | | |
| — 2016: 4 million shares | | | | |
| Noncontrolling interests | **1,361** | 1,245 | | |
| Total preferred and preference stock of subsidiaries and noncontrolling interests | **1,361** | 1,854 | **1.9** | 2.7 |
| Total stockholders' equity | **25,528** | 26,612 | | |
| **Total Capitalization** | **$ 70,314** | $ 69,523 | **100.0%** | 100.0% |

The accompanying notes are an integral part of these consolidated financial statements.

**CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY**
**For the Years Ended December 31, 2017 , 2016 , and 2015**
**Southern Company and Subsidiary Companies 2017 Annual Report**

| | Southern Company Common Stockholders' Equity | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Number of Common Shares | | Common Stock | | | | | | | |
| | Issued | Treasury | Par Value | Paid-In Capital | Treasury | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Preferred and Preference Stock of Subsidiaries | Noncontrolling Interests | Total |
| | *(in thousands)* | | | | | | *(in millions)* | | | |
| **Balance at December 31, 2014** | 908,502 | (725) | $4,539 | $ 5,955 | $ (26) | $ 9,609 | $ (128) | $ 756 | $ 221 | $ 20,926 |
| Consolidated net income attributable to Southern Company | — | — | — | — | — | 2,367 | — | — | — | 2,367 |
| Other comprehensive income (loss) | — | — | — | — | — | — | (2) | — | — | (2) |
| Stock issued | 6,571 | (2,599) | 33 | 223 | — | — | — | — | — | 256 |
| Stock-based compensation | — | — | — | 100 | — | — | — | — | — | 100 |
| Stock repurchased, at cost | — | — | — | — | (115) | — | — | — | — | (115) |
| Cash dividends of $2.1525 per share | — | — | — | — | — | (1,959) | — | — | — | (1,959) |
| Preference stock redemption | — | — | — | — | — | — | — | (150) | — | (150) |
| Contributions from noncontrolling interests | — | — | — | — | — | — | — | — | 567 | 567 |
| Distributions to noncontrolling interests | — | — | — | — | — | — | — | — | (18) | (18) |
| Net loss attributable to noncontrolling interests | — | — | — | — | — | — | — | — | 12 | 12 |
| Other | — | (28) | — | 4 | (1) | (7) | — | 3 | (1) | (2) |
| **Balance at December 31, 2015** | 915,073 | (3,352) | 4,572 | 6,282 | (142) | 10,010 | (130) | 609 | 781 | 21,982 |
| Consolidated net income attributable to Southern Company | — | — | — | — | — | 2,448 | — | — | — | 2,448 |
| Other comprehensive income (loss) | — | — | — | — | — | — | (50) | — | — | (50) |
| Stock issued | 76,140 | 2,599 | 380 | 3,263 | 115 | — | — | — | — | 3,758 |
| Stock-based compensation | — | — | — | 120 | — | — | — | — | — | 120 |
| Cash dividends of $2.2225 per share | — | — | — | — | — | (2,104) | — | — | — | (2,104) |
| Contributions from noncontrolling interests | — | — | — | — | — | — | — | — | 618 | 618 |
| Distributions to noncontrolling interests | — | — | — | — | — | — | — | — | (57) | (57) |
| Purchase of membership interests from noncontrolling interests | — | — | — | — | — | — | — | — | (129) | (129) |
| Net income attributable to noncontrolling interests | — | — | — | — | — | — | — | — | 32 | 32 |
| Other | — | (66) | — | (4) | (4) | 2 | — | — | — | (6) |
| **Balance at December 31, 2016** | **991,213** | **(819)** | **4,952** | **9,661** | **(31)** | **10,356** | **(180)** | **609** | **1,245** | **26,612** |
| Consolidated net income attributable to Southern Company | — | — | — | — | — | **842** | — | — | — | **842** |
| Other comprehensive income (loss) | — | — | — | — | — | — | **(9)** | — | — | **(9)** |
| Stock issued | **17,319** | — | **86** | **707** | — | — | — | — | — | **793** |
| Stock-based compensation | — | — | — | **105** | — | — | — | — | — | **105** |
| Cash dividends of $2.3000 per share | — | — | — | — | — | **(2,300)** | — | — | — | **(2,300)** |
| Preferred and preference stock redemptions | — | — | — | — | — | — | — | **(609)** | — | **(609)** |
| Contributions from noncontrolling interests | — | — | — | — | — | — | — | — | **79** | **79** |
| Distributions to noncontrolling interests | — | — | — | — | — | — | — | — | **(122)** | **(122)** |
| Net income attributable to noncontrolling interests | — | — | — | — | — | — | — | — | **44** | **44** |
| Reclassification from redeemable noncontrolling interests | — | — | — | — | — | — | — | — | **114** | **114** |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Other | — | (110) | — | (4) | (5) | (13) | — | — | 1 | (21) |
| **Balance at December 31, 2017** | **1,008,532** | **(929)** | **$5,038** | **$ 10,469** | **$ (36)** | **$ 8,885** | **$ (189)** | **$ —** | **$ 1,361** | **$ 25,528** |

The accompanying notes are an integral part of these consolidated financial statements.

**Index to the Notes to Financial Statements**

**NOTES (continued)**
**Southern Company and Subsidiary Companies 2017 Annual Report**

## 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

### General

The Southern Company (Southern Company or the Company) is the parent company of four traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), SCS, Southern Linc, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, PowerSecure (as of May 9, 2016), and other direct and indirect subsidiaries. The traditional electric operating companies – Alabama Power, Georgia Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. Southern Power develops, constructs, acquires, owns, and manages power generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Company Gas distributes natural gas through the natural gas distribution utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. Southern Linc provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber optics services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases and for other electric services. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants and is managing construction of Plant Vogtle Units 3 and 4. PowerSecure is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure. See Note 12 under "Southern Company Gas – Proposed Sale of Elizabethtown Gas and Elkton Gas" for information regarding agreements entered into by a wholly-owned subsidiary of Southern Company Gas to sell two of its natural gas distribution utilities.

The financial statements reflect Southern Company's investments in the subsidiaries on a consolidated basis. The equity method is used for entities in which the Company has significant influence but does not control and for variable interest entities where the Company has an equity investment but is not the primary beneficiary. Intercompany transactions have been eliminated in consolidation.

The traditional electric operating companies, Southern Power, certain subsidiaries of Southern Company Gas, and certain other subsidiaries are subject to regulation by the FERC, and the traditional electric operating companies and natural gas distribution utilities are also subject to regulation by their respective state PSCs or other applicable state regulatory agencies. As such, the consolidated financial statements reflect the effects of rate regulation in accordance with GAAP and comply with the accounting policies and practices prescribed by relevant state PSCs or other applicable state regulatory agencies. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation. These reclassifications had no impact on Southern Company's results of operations, financial position, or cash flows.

In 2015, Georgia Power identified an error affecting the billing to a small number of large commercial and industrial customers under a rate plan allowing for variable demand-driven pricing from January 1, 2013 to June 30, 2015. In the second quarter 2015, Georgia Power recorded an out of period adjustment of approximately $75 million to decrease retail revenues, resulting in a decrease to net income of approximately $47 million . Georgia Power evaluated the effects of this error on the interim and annual periods that included the billing error. Based on an analysis of qualitative and quantitative factors, Georgia Power determined the error was not material to any affected period and, therefore, an amendment of previously filed financial statements was not required.

### Recently Issued Accounting Standards

#### *Revenue*

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers* (ASC 606), replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the new standard is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

Most of Southern Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity or natural gas without a defined contractual term , as well as longer-term contractual commitments, including PPAs and non-derivative natural gas asset management and optimization arrangements.

Southern Company has completed the evaluation of all revenue streams and determined that the adoption of ASC 606 will not change the current timing of revenue recognition for such transactions. Some revenue arrangements, such as certain PPAs , energy-related derivatives, and alternative revenue programs, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed or presented separately from revenues under ASC 606 on Southern Company's financial statements. Southern Company has concluded contributions in aid of construction are not in scope for ASC 606 and will continue to be accounted for as an offset to property, plant, and equipment.

The new standard is effective for reporting periods beginning after December 15, 2017. Southern Company applied the modified retrospective method of adoption effective January 1, 2018. Southern Company also utilized practical expedients which allowed it to apply the standard to open contracts at the date of adoption and to reflect the aggregate effect of all modifications when identifying performance obligations and allocating the transaction price for contracts modified before the effective date. Under the modified retrospective method of adoption, prior year reported results are not restated; however, a cumulative-effect adjustment to retained earnings at January 1, 2018 is recorded. In addition, quarterly disclosures will include comparative information on 2018 financial statement line items under current guidance. The adoption of ASC 606 did not result in a cumulative-effect adjustment .

***Leases***

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged and there is no change to the accounting for existing leveraged leases. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018 and Southern Company will adopt the new standard effective January 1, 2019.

Southern Company is currently implementing an information technology system along with the related changes to internal controls and accounting policies that will support the accounting for leases under ASU 2016-02. In addition, Southern Company has substantially completed a detailed inventory and analysis of its leases. In terms of rental charges and duration of contracts, the most significant leases relate to cellular towers and PPAs where certain of Southern Company's subsidiaries are the lessee and to land and outdoor lighting where certain of Southern Company's subsidiaries are the lessor. The traditional electric operating companies are currently analyzing pole attachment agreements, and a lease determination has not been made at this time. While Southern Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on Southern Company's balance sheet.

***Other***

In March 2016, the FASB issued ASU No. 2016-09, *Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, Southern Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. Southern Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. Southern Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of Southern Company. See Notes 5 and 8 for disclosures impacted by ASU 2016-09.

In November 2016, the FASB issued ASU No. 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash* (ASU 2016-18). ASU 2016-18 eliminates the need to reflect transfers between cash and restricted cash in operating, investing, and financing activities in the statement of cash flows. Upon adoption, the net change in cash and cash equivalents during the period will include amounts generally described as restricted cash or restricted cash equivalents. ASU 2016-18 is effective for fiscal years beginning after December 15, 2017, and will be applied retrospectively to each period presented. Southern Company adopted ASU 2016-18 effective January 1, 2018 with no material impact on its financial statements.

On January 26, 2017, the FASB issued ASU No. 2017-04, *Intangibles – Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment* (ASU 2017-04). ASU 2017-04 removes the requirement to compare the implied fair value of goodwill with the carrying amount as part of Step 2 of the goodwill impairment test. Under the new standard, the goodwill impairment loss will be measured as the excess of a reporting unit's carrying amount over its fair value, not exceeding the total amount of goodwill allocated to that reporting unit, which may increase the frequency of goodwill impairment charges if a future goodwill impairment test does not pass the Step 1 evaluation. ASU 2017-04 is effective prospectively for periods beginning on or after

December 15, 2019, with early adoption permitted. Southern Company adopted ASU 2017-04 effective January 1, 2018 with no impact on its financial statements.

On March 10, 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017-07). ASU 2017-07 requires that an employer report the service cost component in the same line item or items as other compensation costs and requires the other components of net periodic pension and postretirement benefit costs to be separately presented in the income statement outside of income from operations. Additionally, only the service cost component is eligible for capitalization, when applicable. However, all cost components remain eligible for capitalization under FERC regulations. ASU 2017-07 will be applied retrospectively for the presentation of the service cost component and the other components of net periodic pension and postretirement benefit costs in the income statement. The capitalization of only the service cost component of net periodic pension and postretirement benefit costs in assets will be applied on a prospective basis. ASU 2017-07 is effective for periods beginning after December 15, 2017. The presentation changes required for net periodic pension and postretirement benefit costs will result in a decrease in Southern Company's operating income and an increase in other income for 2016 and 2017 and are expected to result in a decrease in operating income and an increase in other income for 2018. Southern Company adopted ASU 2017-07 effective January 1, 2018 with no material impact on its financial statements.

On August 28, 2017, the FASB issued ASU No. 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities* (ASU 2017-12), amending the hedge accounting recognition and presentation requirements. ASU 2017-12 makes more financial and non-financial hedging strategies eligible for hedge accounting, amends the related presentation and disclosure requirements, and simplifies hedge effectiveness assessment requirements. ASU 2017-12 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. Southern Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

**Regulatory Assets and Liabilities**

The traditional electric operating companies and natural gas distribution utilities are subject to accounting requirements for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

| | 2017 | 2016 | Note |
|---|---|---|---|
| | *(in millions)* | | |
| Retiree benefit plans | **$ 3,931** | $ 3,959 | (a,n) |
| Asset retirement obligations-asset | **1,133** | 1,080 | (b,n) |
| Deferred income tax charges | **814** | 1,590 | (b,p) |
| Environmental remediation-asset | **511** | 491 | (j,n) |
| Property damage reserves-asset | **333** | 206 | (i) |
| Under recovered regulatory clause revenues | **317** | 273 | (g) |
| Remaining net book value of retired assets | **306** | 351 | (o) |
| Loss on reacquired debt | **223** | 243 | (c) |
| Vacation pay | **183** | 182 | (f,n) |
| Long-term debt fair value adjustment | **138** | 155 | (d) |
| Deferred PPA charges | **119** | 141 | (e,n) |
| Kemper County energy facility | **88** | 201 | (h) |
| Other regulatory assets | **511** | 487 | (k) |
| Deferred income tax credits | **(7,261)** | (219) | (b,p) |
| Other cost of removal obligations | **(2,684)** | (2,774) | (b) |
| Over recovered regulatory clause revenues | **(155)** | (203) | (g) |
| Property damage reserves-liability | **(135)** | (177) | (l) |
| Other regulatory liabilities | **(266)** | (120) | (m) |
| Total regulatory assets (liabilities), net | **$ (1,894)** | $ 5,866 | |

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Recovered and amortized over the average remaining service period which may range up to 15 years . See Note 2 for additional information.

(b) Asset retirement and other cost of removal obligations are recorded, deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 80 years . Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.

(c) Recovered over either the remaining life of the original issue or, if refinanced, over the remaining life of the new issue, which may range up to 50 years .

(d) Recovered over the remaining life of the original debt issuances, which range up to 21 years . For additional information see Note 12 under " Southern Company – Merger with Southern Company Gas ."

(e) Recovered over the life of the PPA for periods up to six years .

(f) Recorded as earned by employees and recovered as paid, generally within one year . This includes both vacation and banked holiday pay.

(g) Recorded and recovered or amortized as approved or accepted by the appropriate state PSCs or other applicable regulatory agencies over periods generally not exceeding 10 years .

(h) Includes $114 million of regulatory assets and $26 million of regulatory liabilities to be recovered over periods of eight and six years , respectively. For additional information, see Note 3 under " Kemper County Energy Facility – Rate Recovery – Kemper Settlement Agreement ."

(i) Previous under-recovery as of December 2013 is recorded and recovered or amortized as approved by the Georgia PSC through 2019. Amortization of $319 million related to the under-recovery from January 2014 through December 2017 is expected to be determined by the Georgia PSC in the 2019 base rate case. See Note 3 under " Regulatory Matters – Georgia Power – Storm Damage Recovery " for additional information.

(j) Recovered through environmental cost recovery mechanisms when the remediation is performed or the work is performed.

(k) Comprised of numerous immaterial components including nuclear outage, fuel-hedging losses, deferred income tax charges - Medicare subsidy, cancelled construction projects, building and generating plant leases, property tax, and other miscellaneous assets. These costs are recorded and recovered or amortized as approved by the appropriate state PSCs over periods generally not exceeding 50 years .

(l) Recovered as storm restoration and potential reliability-related expenses are incurred as approved by the appropriate state PSCs.

(m) Comprised of numerous immaterial components including retiree benefit plans, fuel-hedging gains, AROs, and other liabilities that are recorded and recovered or amortized as approved by the appropriate state PSCs or other applicable regulatory agencies generally over periods not exceeding 20 years .

(n) Not earning a return as offset in rate base by a corresponding asset or liability.

(o) Amortized as approved by the appropriate state PSCs over periods generally up to 48 years .

(p) As a result of the Tax Reform Legislation, these accounts include certain deferred income tax assets and liabilities not subject to normalization. The recovery and amortization of these amounts will be determined by the appropriate state PSCs or other applicable regulatory agencies. See Note 3 under " Regulatory Matters " and Note 5 for additional information.

In the event that a portion of a traditional electric operating company's or a natural gas distribution utility's operations is no longer subject to applicable accounting rules for rate regulation, such company would be required to write off to income or reclassify to accumulated OCI related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the traditional electric operating company or natural gas distribution utility would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under " Regulatory Matters – Alabama Power ," " – Georgia Power ," " – Gulf Power ," and " – Southern Company Gas " and " Kemper County Energy Facility " for additional information.

**Revenues**

Wholesale capacity revenues from PPAs are recognized either on a levelized basis over the appropriate contract period or the amount billable under the contract terms. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Retail rates for the traditional electric operating companies and natural gas distribution utilities may include provisions to adjust billings for fluctuations in fuel and purchased gas costs, fuel hedging, the energy component of purchased power costs, and certain other costs. For the traditional electric operating companies, revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors.

The tariffs for several of the natural gas distribution utilities include provisions which allow for the recognition of certain revenues prior to the time such revenues are billed to customers, so long as the amounts recognized will be collected from customers within 24 months . Programs of this type include weather normalization adjustments, revenue normalization mechanisms, and revenue true-up adjustments and are referred to as alternative revenue programs.

Southern Company's electric utility subsidiaries and Southern Company Gas have a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

**Fuel Costs**

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel.

**Cost of Natural Gas**

Excluding Atlanta Gas Light, which does not sell natural gas to end-use customers, Southern Company Gas charges its utility customers for natural gas consumed using natural gas cost recovery mechanisms set by the applicable state regulatory agencies. Under these mechanisms, all prudently-incurred natural gas costs are passed through to customers without markup, subject to regulatory review. Southern Company Gas defers or accrues the difference between the actual cost of natural gas and the amount of commodity revenue earned in a given period such that no operating income is recognized related to these costs. The deferred or accrued amount is either billed or refunded to customers prospectively through adjustments to the commodity rate. Deferred and accrued natural gas costs are included in the balance sheets as regulatory assets and regulatory liabilities, respectively.

**Income and Other Taxes**

Southern Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income. In accordance with regulatory requirements, deferred federal ITCs for the traditional electric operating companies and Southern Company Gas are amortized over the average lives of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Under current tax law, certain projects at Southern Power are eligible for federal ITCs or cash grants. Southern Power has elected to receive ITCs. The credits are recorded as a deferred credit and are amortized to income tax expense over the life of the asset. Furthermore, the tax basis of the asset is reduced by 50% of the credits received, resulting in a net deferred tax asset. Southern Power has elected to recognize the tax benefit of this basis difference as a reduction to income tax expense in the year in which the plant reaches commercial operation. In addition, certain projects are eligible for federal PTCs, which are recorded to income tax expense based on KWH production.

Federal ITCs and PTCs, as well as state ITCs and other state tax credits available to reduce income taxes payable, were not fully utilized in 2017 and will be carried forward and utilized in future years. In addition, Southern Company is expected to have a consolidated federal net operating loss (NOL) carryforward for the 2017 tax year along with various state NOL carryforwards, which would result in income tax benefits in the future, if utilized. See Note 5 under " Current and Deferred Income Taxes – Tax Credit Carryforwards " and " – Net Operating Loss " for additional information.

Southern Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under " Unrecognized Tax Benefits " for additional information.

**Property, Plant, and Equipment**

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and cost of equity funds used during construction.

The Southern Company system's property, plant, and equipment in service consisted of the following at December 31:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| Electric utilities: | | |
| Generation | $ 51,279 | $ 48,836 |
| Transmission | 11,562 | 11,156 |
| Distribution | 19,239 | 18,418 |
| General | 4,276 | 4,629 |
| Plant acquisition adjustment | 126 | 126 |
| Electric utility plant in service | 86,482 | 83,165 |
| Natural gas distribution utilities: | | |
| Transportation and distribution | 13,078 | 11,996 |
| Utility plant in service | 99,560 | 95,161 |
| Information technology equipment and software | 752 | 544 |
| Communications equipment | 456 | 424 |
| Storage facilities | 1,598 | 1,463 |
| Other | 1,176 | 824 |
| Total other plant in service | 3,982 | 3,255 |
| Total plant in service | $ 103,542 | $ 98,416 |

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred or performed with the exception of nuclear refueling costs. In accordance with their respective state PSC orders, Alabama Power and Georgia Power defer and amortize nuclear refueling costs over the unit's operating cycle, which ranges from 18 to 24 months .

Assets acquired under a capital lease are included in property, plant, and equipment and are further detailed in the table below:

| | Asset Balances at December 31, | |
|---|---|---|
| | 2017 | 2016 |
| | *(in millions)* | |
| Office buildings | $ 216 | $ 61 |
| Nitrogen plant (*) | — | 83 |
| Computer-related equipment | 51 | 63 |
| Gas pipeline | 6 | 6 |
| Less: Accumulated amortization | (72) | (69) |
| Balance, net of amortization | $ 201 | $ 144 |

(*) Represents a nitrogen supply agreement for the air separation unit of the Kemper County energy facility, which was terminated following the suspension of the gasifier portion of the project. See Note 6 under "Capital Leases" for additional information.

The amount of non-cash property additions recognized for the years ended December 31, 2017 , 2016 , and 2015 was $985 million , $1.3 billion , and $844 million , respectively. These amounts are comprised of construction-related accounts payable outstanding at each year end. Also, the amount of non-cash property additions associated with capitalized leases for the years ended December 31, 2017 , 2016 , and 2015 was $162 million , $18 million , and $13 million , respectively.

### Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 2.9% in 2017 and 3.0% in each of 2016 and 2015 . Depreciation studies are conducted periodically to update the composite rates. These studies are filed with the respective state PSC and/or other applicable state and federal regulatory agencies for the traditional electric operating companies and natural gas distribution utilities. Accumulated depreciation for utility plant in service totaled $30.8 billion and $29.3 billion at December 31, 2017 and 2016 , respectively. When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. Certain of Southern Power's generation assets related to natural gas-fired facilities are depreciated on a units-of-production basis, using hours or starts, to better match outage and maintenance costs to the usage of, and revenues from, these assets.

Under the terms of the 2013 ARP, Georgia Power amortized approximately $14 million annually from 2014 through 2016 of its remaining regulatory liability related to other cost of removal obligations.

See Note 3 under " Regulatory Matters – Gulf Power – Retail Base Rate Cases " for information regarding depreciation and amortization adjustments related to the other cost of removal regulatory liability.

Depreciation of the original cost of other plant in service is provided primarily on a straight-line basis over estimated useful lives ranging from two to 65 years . Accumulated depreciation for other plant in service totaled $673 million and $550 million at December 31, 2017 and 2016 , respectively.

### Asset Retirement Obligations and Other Costs of Removal

AROs are computed as the present value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities. Each traditional electric operating company and natural gas distribution utility has received accounting guidance from its state PSC or applicable state regulatory agency allowing the continued accrual or recovery of other retirement costs for long-lived assets that it does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability and amounts to be recovered are reflected in the balance sheet as a regulatory asset.

The liability for AROs primarily relates to facilities that are subject to the Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA in 2015 (CCR Rule), principally ash ponds, and the decommissioning of the Southern Company system's nuclear facilities – Alabama Power's Plant Farley and Georgia Power's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2. In addition, the Southern Company system has retirement obligations related to various landfill sites, asbestos removal, mine reclamation, land restoration related to solar and wind facilities, and disposal of polychlorinated biphenyls in certain transformers. The Southern Company system also has identified retirement obligations related to certain electric transmission and distribution facilities, certain wireless communication towers, property associated with the Southern Company system's rail lines and natural gas pipelines, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded as the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. The Company will continue to recognize in the statements of income allowed removal costs in accordance with regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the various state PSCs, and are reflected in the balance sheets. See " Nuclear Decommissioning " herein for additional information on amounts included in rates.

Details of the AROs included in the balance sheets are as follows:

| | | 2017 | | 2016 |
|---|---|---|---|---|
| | | *(in millions)* | | |
| Balance at beginning of year | **$** | **4,514** | $ | 3,759 |
| Liabilities incurred | | **16** | | 66 |
| Liabilities settled | | **(177)** | | (171) |
| Accretion | | **179** | | 162 |
| Cash flow revisions | | **292** | | 698 |
| Balance at end of year | **$** | **4,824** | $ | 4,514 |

In 2017 and 2016 , the increases in cash flow revisions are primarily related to changes in closure strategy for ash ponds, landfills, and gypsum cells and the increases in liabilities settled are primarily related to ash pond closure activity.

The cost estimates for AROs related to the CCR Rule are based on information as of December 31, 2017 using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure. As further analysis is performed and closure details are developed, the traditional electric operating companies will continue to periodically update these cost estimates as necessary.

**Nuclear Decommissioning**

The NRC requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. Alabama Power and Georgia Power have external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and state PSCs, as well as the IRS. While Alabama Power and Georgia Power are allowed to prescribe an overall investment policy to the Funds' managers, neither Southern Company nor its subsidiaries or affiliates are allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of Southern Company, Alabama Power, and Georgia Power. The Funds' managers are authorized, within certain investment guidelines, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

Southern Company records the investment securities held in the Funds at fair value, as disclosed in Note 10, as management believes that fair value best represents the nature of the Funds. Gains and losses, whether realized or unrealized, are recorded in the regulatory liability for AROs in the balance sheets and are not included in net income or OCI. Fair value adjustments and realized gains and losses are determined on a specific identification basis.

The Funds at Georgia Power participate in a securities lending program through the managers of the Funds. Under this program, the Funds' investment securities are loaned to institutional investors for a fee. Securities loaned are fully collateralized by cash, letters of credit, and/or securities issued or guaranteed by the U.S. government or its agencies or instrumentalities. As of December 31, 2017 and 2016 , approximately $76 million and $56 million , respectively, of the fair market value of the Funds' securities were on loan and pledged to creditors under the Funds' managers' securities lending program. The fair value of the collateral received was approximately $77 million and $58 million at December 31, 2017 and 2016 , respectively, and can only be sold by the borrower upon the return of the loaned securities. The collateral received is treated as a non-cash item in the statements of cash flows.

At December 31, 2017 , investment securities in the Funds totaled $1.8 billion , consisting of equity securities of $1.1 billion , debt securities of $725 million , and $47 million of other securities. At December 31, 2016 , investment securities in the Funds totaled $1.6 billion , consisting of equity securities of $878 million , debt securities of $685 million , and $41 million of other securities. These amounts include the investment securities pledged to creditors and collateral received and exclude receivables related to investment income and pending investment sales and payables related to pending investment purchases and the securities lending program.

Sales of the securities held in the Funds resulted in cash proceeds of $0.8 billion , $1.2 billion , and $1.4 billion in 2017 , 2016 , and 2015 , respectively, all of which were reinvested. For 2017 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $233 million , which included $181 million related to unrealized gains on securities held in the Funds at December 31, 2017 . For 2016 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $114 million , which included $48 million related to unrealized losses on securities held in the Funds at

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December 31, 2016 . For 2015 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $11 million , which included $83 million related to unrealized gains and losses on securities held in the Funds at December 31, 2015 . While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of the securities and purpose for which the securities were acquired.

For Alabama Power, approximately $18 million and $19 million at December 31, 2017 and 2016 , respectively, previously recorded in internal reserves is being transferred into the Funds through 2040 as approved by the Alabama PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. Alabama Power and Georgia Power have filed plans with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

At December 31, 2017 and 2016 , the accumulated provisions for the external decommissioning trust funds were as follows:

| | External Trust Funds | |
|---|---|---|
| | **2017** | 2016 |
| | *(in millions)* | |
| Plant Farley | **$ 902** | $ 790 |
| Plant Hatch | **583** | 511 |
| Plant Vogtle Units 1 and 2 | **346** | 303 |

Site study cost is the estimate to decommission a specific facility as of the site study year. The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates. The estimated costs of decommissioning as of December 31, 2017 based on the most current studies, which were performed in 2013 for Alabama Power's Plant Farley and in 2015 for the Georgia Power plants, were as follows for Alabama Power's Plant Farley and Georgia Power's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2:

| | Plant Farley | Plant Hatch | Plant Vogtle Units 1 and 2 |
|---|---|---|---|
| Decommissioning periods: | | | |
| Beginning year | 2037 | 2034 | 2047 |
| Completion year | 2076 | 2075 | 2079 |
| | | *(in millions)* | |
| Site study costs: | | | |
| Radiated structures | $ 1,362 | $ 678 | $ 568 |
| Spent fuel management | — | 160 | 147 |
| Non-radiated structures | 80 | 64 | 89 |
| Total site study costs | $ 1,442 | $ 902 | $ 804 |

For ratemaking purposes, Alabama Power's decommissioning costs are based on the site study, and Georgia Power's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities and the site study estimate for spent fuel management as of 2012. Under the 2013 ARP, the Georgia PSC approved Georgia Power's annual decommissioning cost for ratemaking of $4 million and $2 million for Plant Hatch and Plant Vogtle Units 1 and 2, respectively. Georgia Power expects the Georgia PSC to review and adjust, if necessary, the amounts collected in rates for nuclear decommissioning costs in Georgia Power's 2019 base rate case. Significant assumptions used to determine these costs for ratemaking were an inflation rate of 4.5% and 2.4% for Alabama Power and Georgia Power, respectively, and a trust earnings rate of 7.0% and 4.4% for Alabama Power and Georgia Power, respectively.

Amounts previously contributed to the Funds for Plant Farley are currently projected to be adequate to meet the decommissioning obligations. Alabama Power will continue to provide site-specific estimates of the decommissioning costs and related projections of funds in the external trust to the Alabama PSC and, if necessary, would seek the Alabama PSC's approval to address any changes in a manner consistent with NRC and other applicable requirements.

**Allowance for Funds Used During Construction and Interest Capitalized**

The traditional electric operating companies and certain of the natural gas distribution utilities record AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently, AFUDC increases the revenue requirement and is recovered over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. Interest related to the construction of new facilities not included in the traditional electric operating companies' and natural gas distribution utilities' regulated rates is capitalized in accordance with standard interest capitalization requirements. AFUDC and interest capitalized, net of income taxes, as a percentage of net income, was 25.5% , 11.4% , and 12.8% for 2017 , 2016 , and 2015 , respectively.

Cash payments for interest totaled $1.7 billion , $1.1 billion , and $809 million in 2017 , 2016 , and 2015 , respectively, net of amounts capitalized of $89 million , $125 million , and $124 million , respectively.

**Impairment of Long-Lived Assets**

Southern Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change. See " Leveraged Leases " herein and Note 3 under " Other Matters " and " Kemper County Energy Facility – Schedule and Cost Estimate " for additional information.

**Goodwill and Other Intangible Assets and Liabilities**

Southern Company's goodwill and other intangible assets and liabilities primarily relate to Southern Company's 2016 acquisitions of PowerSecure and Southern Company Gas. See Note 12 under " Southern Company – Acquisition of PowerSecure " and " – Merger with Southern Company Gas " for additional information. Also see Note 12 under " Southern Power " for additional information regarding other intangible assets related to Southern Power's PPA fair value adjustments.

At December 31, 2017 and 2016 , goodwill was $6.3 billion . Goodwill is not amortized, but is subject to an annual impairment test during the fourth quarter of each year, or more frequently if impairment indicators arise. Southern Company evaluated its goodwill in the fourth quarter 2017 and determined that no impairment was required.

At December 31, 2017 and 2016 , other intangible assets were as follows:

| | | At December 31, 2017 | | | At December 31, 2016 | | |
|---|---|---|---|---|---|---|---|
| | **Estimated Useful Life** | **Gross Carrying Amount** | **Accumulated Amortization** | **Other Intangible Assets, Net** | **Gross Carrying Amount** | **Accumulated Amortization** | **Other Intangible Assets, Net** |
| | | | *(in millions)* | | | *(in millions)* | |
| ***Other intangible assets subject to amortization:*** | | | | | | | |
| Customer relationships | 11-26 years | $ 288 | $ (83) | $ 205 | $ 268 | $ (32) | $ 236 |
| Trade names | 5-28 years | 159 | (17) | 142 | 158 | (5) | 153 |
| Storage and transportation contracts | 1-5 years | 64 | (34) | 30 | 64 | (2) | 62 |
| PPA fair value adjustments | 10-20 years | 456 | (47) | 409 | 456 | (22) | 434 |
| Other | 1-12 years | 17 | (5) | 12 | 11 | (1) | 10 |
| ***Total other intangible assets subject to amortization*** | | $ 984 | $ (186) | $ 798 | $ 957 | $ (62) | $ 895 |
| ***Other intangible assets not subject to amortization:*** | | | | | | | |
| Federal Communications Commission licenses | | 75 | — | 75 | 75 | — | 75 |
| ***Total other intangible assets*** | | $ 1,059 | $ (186) | $ 873 | $ 1,032 | $ (62) | $ 970 |

Amortization associated with other intangible assets in 2017 , 2016 , and 2015 totaled $124 million , $50 million , and $3 million , respectively.

As of December 31, 2017 , the estimated amortization associated with other intangible assets for the next five years is as follows:

| | **Amortization** |
|---|---|
| | *(in millions)* |
| 2018 | $ 95 |
| 2019 | 77 |
| 2020 | 65 |
| 2021 | 56 |
| 2022 | 51 |

Included in other deferred credits and liabilities on the balance sheet is $91 million of intangible liabilities that were recorded during acquisition accounting for transportation contracts at Southern Company Gas. At December 31, 2017 , the accumulated amortization of these intangible liabilities was $50 million . The remaining estimated amortization associated with the intangible liabilities that will be recorded in natural gas revenues is as follows:

| | **Amortization** |
|---|---|
| | *(in millions)* |
| 2018 | $ 24 |
| 2019 | 17 |

**Storm Damage Reserves**

Each traditional electric operating company maintains a reserve to cover or is allowed to defer and recover the cost of damages from major storms to its transmission and distribution lines and generally the cost of uninsured damages to its generation facilities and other property. In accordance with their respective state PSC orders, the traditional electric operating companies accrued $41 million in 2017 and $40 million in each of 2016 and 2015 . Alabama Power, Gulf Power, and Mississippi Power also have authority based on orders from their state PSCs to accrue certain additional amounts as circumstances warrant. In 2017 , 2016 , and 2015 , there were no such additional accruals. See Note 3 under " Regulatory Matters – Alabama Power – Rate NDR " and

" Regulatory Matters – Georgia Power – Storm Damage Recovery " for additional information regarding Alabama Power's NDR and Georgia Power's deferred storm costs, respectively.

**Leveraged Leases**

A subsidiary of Southern Holdings has several leveraged lease agreements, with original terms ranging up to 45 years , which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. Southern Company reviews all important lease assumptions at least annually, or more frequently if events or changes in circumstances indicate that a change in assumptions has occurred or may occur. These assumptions include the effective tax rate, the residual value, the credit quality of the lessees, and the timing of expected tax cash flows.

The ability of the lessees to make required payments to the Southern Holdings subsidiary is dependent on the operational performance of the assets. In the last six months of 2017, the financial and operational performance of one of the lessees and the associated generation assets has raised significant concerns about the short-term ability of the generation assets to produce cash flows sufficient to support ongoing operations and the lessee's contractual obligations and its ability to make the remaining semi-annual lease payments to the Southern Holdings subsidiary beginning in June 2018. These operational challenges may also impact the expected residual value of the assets at the end of the lease term in 2047. If the June 2018 (or any future) lease payment is not paid in full, the Southern Holdings subsidiary may be unable to make its corresponding payment to the holders of the underlying non-recourse debt related to the generation assets. Failure to make the required payment to the debtholders would represent an event of default that would give the debtholders the right to foreclose on, and take ownership of, the generation assets from the Southern Holdings subsidiary, in effect terminating the lease and resulting in the write-off of the related lease receivable which had a balance of approximately $86 million as of December 31, 2017 . Southern Company has evaluated the recoverability of the lease receivable and the expected residual value of the generation assets at the end of the lease under various scenarios and has concluded that its investment in the leveraged lease is not impaired as of December 31, 2017 . Southern Company will continue to monitor the operational performance of the underlying assets and evaluate the ability of the lessee to continue to make the required lease payments, including the lease payment due in June 2018. The ultimate outcome of this matter cannot be determined at this time.

Southern Company's net investment in domestic and international leveraged leases consists of the following at December 31:

| | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| Net rentals receivable | **$ 1,498** | $ 1,481 |
| Unearned income | **(723)** | (707) |
| Investment in leveraged leases | **775** | 774 |
| Deferred taxes from leveraged leases | **(252)** | (309) |
| Net investment in leveraged leases | **$ 523** | $ 465 |

A summary of the components of income from the leveraged leases follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| Pretax leveraged lease income | **$ 25** | $ 25 | $ 20 |
| Net impact of Tax Reform Legislation | **48** | — | — |
| Income tax expense | **(9)** | (9) | (7) |
| Net leveraged lease income | **$ 64** | $ 16 | $ 13 |

**Cash and Cash Equivalents**

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

**Materials and Supplies**

Generally, materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

**Fuel Inventory**

Fuel inventory includes the average cost of coal, natural gas, oil, transportation, and emissions allowances of the electric utilities. Fuel is recorded to inventory when purchased and then expensed, at weighted average cost, as used and recovered by the traditional electric operating companies through fuel cost recovery rates approved by each state PSC. Emissions allowances granted by the EPA are included in inventory at zero cost.

**Natural Gas for Sale**

The natural gas distribution utilities, with the exception of Nicor Gas, carry natural gas inventory on a weighted average cost of gas (WACOG) basis.

Nicor Gas' natural gas inventory is carried at cost on a LIFO basis. Inventory decrements occurring during the year that are restored prior to year end are charged to cost of natural gas at the estimated annual replacement cost. Inventory decrements that are not restored prior to year end are charged to cost of natural gas at the actual LIFO cost of the inventory layers liquidated. The cost of natural gas, including inventory costs, is recovered from customers under a purchased gas recovery mechanism adjusted for differences between actual costs and amounts billed; therefore, LIFO liquidations have no impact on Southern Company's net income.

Natural gas inventories for Southern Company Gas' non-utility businesses are carried at the lower of weighted average cost or current market price, with cost determined on a WACOG basis. For any declines in market prices below the WACOG considered to be other than temporary, an adjustment is recorded to reduce the value of natural gas inventories to market value.

**Financial Instruments**

Southern Company and its subsidiaries use derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, electricity purchases and sales, and occasionally foreign currency exchange rates. All derivative financial instruments are recognized as either assets or liabilities on the balance sheets (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 10 for additional information regarding fair value. Substantially all of the Southern Company system's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the traditional electric operating companies' and the natural gas distribution utilities' fuel-hedging programs result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded on a net basis in the statements of income. Cash flows from derivatives are classified on the statements of cash flows in the same category as the hedged item. See Note 11 for additional information regarding derivatives.

The Company offsets fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. At December 31, 2017 , the amount included in accounts payable in the balance sheets that the Company has recognized for the obligation to return cash collateral arising from derivative instruments was immaterial.

Southern Company is exposed to potential losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

**Comprehensive Income**

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges and marketable securities, certain changes in pension and other postretirement benefit plans, reclassifications for amounts included in net income, and dividends on preferred and preference stock of subsidiaries.

Accumulated OCI (loss) balances, net of tax effects, were as follows:

| | Qualifying Hedges | Pension and Other Postretirement Benefit Plans | Accumulated Other Comprehensive Income (Loss) |
|---|---|---|---|
| | | *(in millions)* | |
| Balance at December 31, 2016 | $ (115) | $ (65) | $ (180) |
| Current period change | (4) | (5) | (9) |
| **Balance at December 31, 2017** | **$ (119)** | **$ (70)** | **$ (189)** |

## 2. RETIREMENT BENEFITS

Southern Company has a defined benefit, trusteed, pension plan covering substantially all employees, with the exception of employees at Southern Company Gas and PowerSecure. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2017 and no mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2018 . Southern Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, Southern Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The traditional electric operating companies fund related other postretirement trusts to the extent required by their respective regulatory commissions. For the year ending December 31, 2018 , no other postretirement trust contributions are expected.

In addition, Southern Company Gas has a qualified defined benefit, trusteed, pension plan covering certain eligible employees, which was closed in 2012 to new employees and reopened to all non-union employees on January 1, 2018. This qualified pension plan is funded in accordance with requirements of ERISA. No contributions to the qualified pension plan were made for the year ended December 31, 2017 and no mandatory contributions to the Southern Company Gas qualified pension plan are anticipated for the year ending December 31, 2018 . Southern Company Gas also provides certain non-qualified defined benefit and defined contribution pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, Southern Company Gas provides certain medical care and life insurance benefits for eligible retired employees through a postretirement benefit plan. Southern Company Gas also has a separate unfunded supplemental retirement health care plan that provides medical care and life insurance benefits to employees of discontinued businesses. For the year ending December 31, 2018 , no other postretirement trust contributions are expected.

### Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the net periodic costs for the pension and other postretirement benefit plans for the following year and the benefit obligations as of the measurement date are presented below.

| **Assumptions used to determine net periodic costs:** | **2017** | 2016 | 2015 |
|---|---|---|---|
| **Pension plans** | | | |
| Discount rate – benefit obligations | **4.40%** | 4.58% | 4.17% |
| Discount rate – interest costs | **3.77** | 3.88 | 4.17 |
| Discount rate – service costs | **4.81** | 4.98 | 4.48 |
| Expected long-term return on plan assets | **7.92** | 8.16 | 8.20 |
| Annual salary increase | **4.37** | 4.37 | 3.59 |
| **Other postretirement benefit plans** | | | |
| Discount rate – benefit obligations | **4.23%** | 4.38% | 4.04% |
| Discount rate – interest costs | **3.54** | 3.66 | 4.04 |
| Discount rate – service costs | **4.64** | 4.85 | 4.39 |
| Expected long-term return on plan assets | **6.84** | 6.66 | 6.97 |
| Annual salary increase | **4.37** | 4.37 | 3.59 |

| **Assumptions used to determine benefit obligations:** | **2017** | 2016 |
|---|---|---|
| **Pension plans** | | |
| Discount rate | **3.80%** | 4.40% |
| Annual salary increase | **4.32** | 4.37 |
| **Other postretirement benefit plans** | | |
| Discount rate | **3.68%** | 4.23% |
| Annual salary increase | **4.32** | 4.37 |

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of eight different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2017 were as follows:

| | **Initial Cost Trend Rate** | **Ultimate Cost Trend Rate** | **Year That Ultimate Rate is Reached** |
|---|---|---|---|
| Pre-65 | 6.50% | 4.50% | 2026 |
| Post-65 medical | 5.00 | 4.50 | 2026 |
| Post-65 prescription | 10.00 | 4.50 | 2026 |

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2017 as follows:

| | **1 Percent Increase** | **1 Percent Decrease** |
|---|---|---|
| | *(in millions)* | |
| Benefit obligation | $ 132 | $ 113 |
| Service and interest costs | 4 | 3 |

**Pension Plans**

The total accumulated benefit obligation for the pension plans was $12.6 billion at December 31, 2017 and $11.3 billion at December 31, 2016 . Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2017 and 2016 were as follows:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Change in benefit obligation** | | |
| Benefit obligation at beginning of year | **$ 12,385** | $ 10,542 |
| Acquisitions | — | 1,244 |
| Service cost | **293** | 262 |
| Interest cost | **455** | 422 |
| Benefits paid | **(596)** | (466) |
| Plan amendments | **(26)** | 39 |
| Actuarial (gain) loss | **1,297** | 342 |
| Balance at end of year | **13,808** | 12,385 |
| **Change in plan assets** | | |
| Fair value of plan assets at beginning of year | **11,583** | 9,234 |
| Acquisitions | — | 837 |
| Actual return (loss) on plan assets | **1,953** | 902 |
| Employer contributions | **52** | 1,076 |
| Benefits paid | **(596)** | (466) |
| Fair value of plan assets at end of year | **12,992** | 11,583 |
| Accrued liability | **$ (816)** | $ (802) |

At December 31, 2017 , the projected benefit obligations for the qualified and non-qualified pension plans were $13.2 billion and $652 million , respectively. All pension plan assets are related to the qualified pension plans.

Amounts presented in the following tables exclude regulatory assets of $334 million associated with unamortized amounts in Southern Company Gas' pension plans prior to its acquisition by Southern Company on July 1, 2016.

Amounts recognized in the balance sheets at December 31, 2017 and 2016 related to the Company's pension plans consist of the following:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| Other regulatory assets, deferred | **$ 3,273** | $ 3,207 |
| Other current liabilities | **(53)** | (53) |
| Employee benefit obligations | **(763)** | (749) |
| Other regulatory liabilities, deferred | **(118)** | (87) |
| Accumulated OCI | **107** | 100 |

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Presented below are the amounts included in accumulated OCI and regulatory assets at December 31, 2017 and 2016 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2018 .

| | Prior Service Cost | Net (Gain) Loss |
|---|---|---|
| | *(in millions)* | |
| **Balance at December 31, 2017:** | | |
| Accumulated OCI | **$ 3** | **$ 104** |
| Regulatory assets | **14** | **3,140** |
| Total | **$ 17** | **$ 3,244** |
| **Balance at December 31, 2016:** | | |
| Accumulated OCI | $ 4 | $ 96 |
| Regulatory assets | 51 | 3,069 |
| Total | $ 55 | $ 3,165 |
| **Estimated amortization in net periodic pension cost in 2018:** | | |
| Accumulated OCI | **$ 1** | **$ 9** |
| Regulatory assets | **4** | **204** |
| Total | **$ 5** | **$ 213** |

The components of OCI and the changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2017 and 2016 are presented in the following table:

| | Accumulated OCI | Regulatory Assets |
|---|---|---|
| | *(in millions)* | |
| **Balance at December 31, 2015** | $ 125 | $ 2,998 |
| Net (gain) loss | (20) | 243 |
| Change in prior service costs | 2 | 37 |
| Reclassification adjustments: | | |
| Amortization of prior service costs | (1) | (13) |
| Amortization of net gain (loss) | (6) | (145) |
| Total reclassification adjustments | (7) | (158) |
| Total change | (25) | 122 |
| **Balance at December 31, 2016** | $ 100 | $ 3,120 |
| Net (gain) loss | **15** | **227** |
| Change in prior service costs | **—** | **(26)** |
| Reclassification adjustments: | | |
| Amortization of prior service costs | **(1)** | **(11)** |
| Amortization of net gain (loss) | **(7)** | **(155)** |
| Total reclassification adjustments | **(8)** | **(166)** |
| Total change | **7** | **35** |
| **Balance at December 31, 2017** | **$ 107** | **$ 3,155** |

Components of net periodic pension cost were as follows:

| | | 2017 | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| | | | | *(in millions)* | | |
| Service cost | **$** | **293** | $ | 262 | $ | 257 |
| Interest cost | | **455** | | 422 | | 445 |
| Expected return on plan assets | | **(897)** | | (782) | | (724) |
| Recognized net (gain) loss | | **162** | | 150 | | 215 |
| Net amortization | | **12** | | 14 | | 25 |
| Net periodic pension cost | **$** | **25** | $ | 66 | $ | 218 |

Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2017 , estimated benefit payments were as follows:

| | | Benefit Payments |
|---|---|---|
| | | *(in millions)* |
| 2018 | $ | 634 |
| 2019 | | 637 |
| 2020 | | 663 |
| 2021 | | 681 |
| 2022 | | 704 |
| 2023 to 2027 | | 3,836 |

**Other Postretirement Benefits**

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2017 and 2016 were as follows:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Change in benefit obligation** | | |
| Benefit obligation at beginning of year | $ 2,297 | $ 1,989 |
| Acquisitions | — | 338 |
| Service cost | 24 | 22 |
| Interest cost | 79 | 76 |
| Benefits paid | (136) | (119) |
| Actuarial (gain) loss | 65 | (16) |
| Plan amendments | 3 | — |
| Retiree drug subsidy | 7 | 7 |
| Balance at end of year | 2,339 | 2,297 |
| **Change in plan assets** | | |
| Fair value of plan assets at beginning of year | 944 | 833 |
| Acquisitions | — | 100 |
| Actual return (loss) on plan assets | 154 | 58 |
| Employer contributions | 84 | 65 |
| Benefits paid | (129) | (112) |
| Fair value of plan assets at end of year | 1,053 | 944 |
| Accrued liability | $ (1,286) | $ (1,353) |

Amounts presented in the following tables exclude regulatory assets of $77 million associated with unamortized amounts in Southern Company Gas' other postretirement benefit plans prior to its acquisition by Southern Company on July 1, 2016.

Amounts recognized in the balance sheets at December 31, 2017 and 2016 related to the Company's other postretirement benefit plans consist of the following:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| Other regulatory assets, deferred | $ 382 | $ 419 |
| Other current liabilities | (5) | (4) |
| Employee benefit obligations | (1,281) | (1,349) |
| Other regulatory liabilities, deferred | (41) | (41) |
| Accumulated OCI | 4 | 7 |

**NOTES (continued)**
**Southern Company and Subsidiary Companies 2017 Annual Report**

Presented below are the amounts included in accumulated OCI and net regulatory assets (liabilities) at December 31, 2017 and 2016 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2018 .

| | Prior Service Cost | Net (Gain) Loss |
|---|---|---|
| | *(in millions)* | |
| **Balance at December 31, 2017:** | | |
| Accumulated OCI | **$ —** | **$ 4** |
| Net regulatory assets | **21** | **320** |
| Total | **$ 21** | **$ 324** |
| **Balance at December 31, 2016:** | | |
| Accumulated OCI | $ — | $ 7 |
| Net regulatory assets | 25 | 353 |
| Total | $ 25 | $ 360 |
| **Estimated amortization as net periodic postretirement benefit cost in 2018:** | | |
| Net regulatory assets | **$ 7** | **$ 14** |

The components of OCI, along with the changes in the balance of net regulatory assets (liabilities), related to the other postretirement benefit plans for the plan years ended December 31, 2017 and 2016 are presented in the following table:

| | Accumulated OCI | Net Regulatory Assets (Liabilities) |
|---|---|---|
| | *(in millions)* | |
| **Balance at December 31, 2015** | $ 8 | $ 411 |
| Net (gain) loss | (1) | (13) |
| Reclassification adjustments: | | |
| Amortization of prior service costs | — | (6) |
| Amortization of net gain (loss) | — | (14) |
| Total reclassification adjustments | — | (20) |
| Total change | (1) | (33) |
| **Balance at December 31, 2016** | $ 7 | $ 378 |
| Net (gain) loss | **(3)** | **(21)** |
| Change in prior service costs | **—** | **3** |
| Reclassification adjustments: | | |
| Amortization of prior service costs | **—** | **(6)** |
| Amortization of net gain (loss) | **—** | **(13)** |
| Total reclassification adjustments | **—** | **(19)** |
| Total change | **(3)** | **(37)** |
| **Balance at December 31, 2017** | **$ 4** | **$ 341** |

Components of the other postretirement benefit plans' net periodic cost were as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| Service cost | **$ 24** | $ 22 | $ 23 |
| Interest cost | **79** | 76 | 78 |
| Expected return on plan assets | **(66)** | (60) | (58) |
| Net amortization | **20** | 21 | 21 |
| Net periodic postretirement benefit cost | **$ 57** | $ 59 | $ 64 |

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

| | **Benefit Payments** | **Subsidy Receipts** | **Total** |
|---|---|---|---|
| | | *(in millions)* | |
| 2018 | $ 144 | $ (7) | $ 137 |
| 2019 | 148 | (8) | 140 |
| 2020 | 151 | (8) | 143 |
| 2021 | 154 | (9) | 145 |
| 2022 | 156 | (9) | 147 |
| 2023 to 2027 | 780 | (48) | 732 |

**Benefit Plan Assets**

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policies for both the pension plans and the other postretirement benefit plans cover a diversified mix of assets as described below. Derivative instruments may be used to gain efficient exposure to the various asset classes and as hedging tools. Additionally, the Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The investment strategy for plan assets related to the Company's qualified pension plans is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns and interest rates, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plans is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Southern Company plan employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices. Management believes the portfolio is well-diversified with no significant concentrations of risk.

*Investment Strategies and Benefit Plan Asset Fair Values*

A description of the major asset classes that the pension and other postretirement benefit plans are comprised of, along with the valuation methods used for fair value measurement, is provided below:

| Description | Valuation Methodology |
|---|---|
| ● **Domestic equity:** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.<br><br>● **International equity:** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches. | Domestic and International equities such as common stocks, American depositary receipts, and real estate investment trusts that trade on public exchanges are classified as Level 1 investments and are valued at the closing price in the active market. Equity funds with unpublished prices are valued as Level 2 when the underlying holdings are comprised of Level 1 or Level 2 equity securities. |
| ● **Fixed income:** A mix of domestic and international bonds. | Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument. |
| ● **Trust-owned life insurance (TOLI):** Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio. | Investments in TOLI policies are classified as Level 2 investments and are valued based on the underlying investments held in the policy's separate accounts. The underlying assets are equity and fixed income pooled funds that are comprised of Level 1 and Level 2 securities. |
| ● **Special situations:** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies, as well as investments in promising new strategies of a longer-term nature.<br><br>● **Real estate:** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.<br><br>● **Private equity:** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt. | Investments in real estate, private equity, and special situations are generally classified as Net Asset Value as a Practical Expedient, since the underlying assets typically do not have publicly available observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. Techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, discounted cash flow analysis, prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals. The fair value of partnerships is determined by aggregating the value of the underlying assets less liabilities. |

The fair values, and actual allocations relative to the target allocations, of Southern Company's pension plan (excluding Southern Company Gas) as of December 31, 2017 and 2016 are presented below. The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

These fair values exclude cash, receivables related to investment income and pending investment sales, and payables related to pending investment purchases.

| | Fair Value Measurements Using | | | | | | |
|---|---|---|---|---|---|---|---|
| As of December 31, 2017: | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Net Asset Value as a Practical Expedient (NAV) | Total | Target Allocation | Actual Allocation |
| | | | *(in millions)* | | | | |
| Assets: | | | | | | | |
| Domestic equity (*) | $ 2,405 | $ 1,159 | $ — | $ — | $ 3,564 | 26% | 31% |
| International equity (*) | 1,555 | 1,403 | — | — | 2,958 | 25 | 25 |
| Fixed income: | | | | | | 23 | 24 |
| U.S. Treasury, government, and agency bonds | — | 841 | — | — | 841 | | |
| Mortgage- and asset-backed securities | — | 8 | — | — | 8 | | |
| Corporate bonds | — | 1,201 | — | — | 1,201 | | |
| Pooled funds | — | 650 | — | — | 650 | | |
| Cash equivalents and other | 217 | 11 | — | — | 228 | | |
| Real estate investments | 469 | — | — | 1,188 | 1,657 | 14 | 13 |
| Special situations | — | — | — | 180 | 180 | 3 | 1 |
| Private equity | — | — | — | 669 | 669 | 9 | 6 |
| Total | $ 4,646 | $ 5,273 | $ — | $ 2,037 | $ 11,956 | 100% | 100% |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

**NOTES (continued)**
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| | Fair Value Measurements Using | | | | | | |
|---|---|---|---|---|---|---|---|
| As of December 31, 2016: | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Net Asset Value as a Practical Expedient (NAV) | Total | Target Allocation | Actual Allocation |
| | *(in millions)* | | | | | | |
| Assets: | | | | | | | |
| Domestic equity (*) | $ 2,010 | $ 927 | $ — | $ — | $ 2,937 | 26% | 29% |
| International equity (*) | 1,231 | 1,110 | — | — | 2,341 | 25 | 22 |
| Fixed income: | | | | | | 23 | 29 |
| U.S. Treasury, government, and agency bonds | — | 588 | — | — | 588 | | |
| Mortgage- and asset-backed securities | — | 13 | — | — | 13 | | |
| Corporate bonds | — | 991 | — | — | 991 | | |
| Pooled funds | — | 524 | — | — | 524 | | |
| Cash equivalents and other | 996 | 2 | — | — | 998 | | |
| Real estate investments | 310 | — | — | 1,152 | 1,462 | 14 | 13 |
| Special situations | — | — | | 180 | 180 | 3 | 2 |
| Private equity | — | — | — | 549 | 549 | 9 | 5 |
| Total | $ 4,547 | $ 4,155 | $ — | $ 1,881 | $ 10,583 | 100% | 100% |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

The fair values of Southern Company Gas' pension plan assets for the period ended December 31, 2017 and 2016 are presented below. The fair value measurements exclude cash, receivables related to investment income, pending investment sales, and payables related to pending investment purchases. Special situations (absolute return and hedge funds) investment assets are presented in the tables below based on the nature of the investment.

| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| As of December 31, 2017: | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Net Asset Value as a Practical Expedient (NAV) | Total |
| | *(in millions)* | | | | |
| Assets: | | | | | |
| Domestic equity (*) | $ 155 | $ 323 | $ — | $ — | $ 478 |
| International equity (*) | — | 166 | — | — | 166 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 85 | — | — | 85 |
| Corporate bonds | — | 39 | — | — | 39 |
| Cash equivalents and other | 84 | 25 | — | 48 | 157 |
| Real estate investments | 3 | — | — | 16 | 19 |
| Private equity | — | — | — | 1 | 1 |
| Total | $ 242 | $ 638 | $ — | $ 65 | $ 945 |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| **As of December 31, 2016:** | **Quoted Prices in Active Markets for Identical Assets (Level 1)** | **Significant Other Observable Inputs (Level 2)** | **Significant Unobservable Inputs (Level 3)** | **Net Asset Value as a Practical Expedient (NAV)** | **Total** |
| | | | *(in millions)* | | |
| Assets: | | | | | |
| Domestic equity (*) | $ 142 | $ 343 | $ — | $ — | $ 485 |
| International equity (*) | — | 185 | — | — | 185 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 85 | — | — | 85 |
| Corporate bonds | — | 41 | — | — | 41 |
| Pooled funds | — | 66 | — | — | 66 |
| Cash equivalents and other | 12 | 5 | — | 83 | 100 |
| Real estate investments | 4 | — | — | 15 | 19 |
| Private equity | — | — | — | 2 | 2 |
| Total | $ 158 | $ 725 | $ — | $ 100 | $ 983 |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

The composition of Southern Company Gas' pension plan assets as of December 31, 2017 and 2016 , along with the targets, is presented below:

| | Target | **2017** | 2016 |
|---|---|---|---|
| **Pension plan assets:** | | | |
| Equity | 53% | **65%** | 69% |
| Fixed Income | 15 | **19** | 20 |
| Cash | 2 | **6** | 1 |
| Other | 30 | **10** | 10 |
| Balance at end of period | 100% | **100%** | 100% |

**NOTES (continued)**
**Southern Company and Subsidiary Companies 2017 Annual Report**

The fair values of Southern Company's (excluding Southern Company Gas) other postretirement benefit plan assets as of December 31, 2017 and 2016 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investment sales, and payables related to pending investment purchases.

| | Fair Value Measurements Using | | | | | | |
|---|---|---|---|---|---|---|---|
| **As of December 31, 2017:** | **Quoted Prices in Active Markets for Identical Assets (Level 1)** | **Significant Other Observable Inputs (Level 2)** | **Significant Unobservable Inputs (Level 3)** | **Net Asset Value as a Practical Expedient (NAV)** | **Total** | **Target Allocation** | **Actual Allocation** |
| | *(in millions)* | | | | | | |
| Assets: | | | | | | | |
| Domestic equity (*) | $ 132 | $ 35 | $ — | $ — | $ 167 | 37% | 40% |
| International equity (*) | 47 | 76 | — | — | 123 | 23 | 23 |
| Fixed income: | | | | | | 30 | 29 |
| U.S. Treasury, government, and agency bonds | — | 32 | — | — | 32 | | |
| Corporate bonds | — | 37 | — | — | 37 | | |
| Pooled funds | — | 55 | — | — | 55 | | |
| Cash equivalents and other | 10 | — | — | — | 10 | | |
| Trust-owned life insurance | — | 426 | — | — | 426 | | |
| Real estate investments | 16 | — | — | 36 | 52 | 5 | 5 |
| Special situations | — | — | — | 5 | 5 | 1 | 1 |
| Private equity | — | — | — | 20 | 20 | 4 | 2 |
| Total | $ 205 | $ 661 | $ — | $ 61 | $ 927 | 100% | 100% |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

**NOTES (continued)**
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| As of December 31, 2016: | Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Net Asset Value as a Practical Expedient (NAV) | Total | Target Allocation | Actual Allocation |
|---|---|---|---|---|---|---|---|
| | *(in millions)* | | | | | | |
| Assets: | | | | | | | |
| Domestic equity [(*)] | $ 118 | $ 28 | $ — | $ — | $ 146 | 39% | 40% |
| International equity [(*)] | 37 | 61 | — | — | 98 | 23 | 21 |
| Fixed income: | | | | | | 29 | 31 |
| U.S. Treasury, government, and agency bonds | — | 24 | — | — | 24 | | |
| Corporate bonds | — | 30 | — | — | 30 | | |
| Pooled funds | — | 49 | — | — | 49 | | |
| Cash equivalents and other | 41 | — | — | — | 41 | | |
| Trust-owned life insurance | — | 382 | — | — | 382 | | |
| Real estate investments | 11 | — | — | 35 | 46 | 5 | 5 |
| Special situations | — | — | — | 5 | 5 | 1 | 1 |
| Private equity | — | — | — | 17 | 17 | 3 | 2 |
| Total | $ 207 | $ 574 | $ — | $ 57 | $ 838 | 100% | 100% |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

The fair values of Southern Company Gas' other postretirement benefit plan assets for the period ended December 31, 2017 and 2016 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investment sales, and payables related to pending investment purchases. Special situations (absolute return and hedge funds) investment assets are presented in the tables below based on the nature of the investment.

| As of December 31, 2017: | Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Net Asset Value as a Practical Expedient (NAV) | Total |
|---|---|---|---|---|---|
| | *(in millions)* | | | | |
| Assets: | | | | | |
| Domestic equity [(*)] | $ 3 | $ 69 | $ — | $ — | $ 72 |
| International equity [(*)] | — | 22 | — | — | 22 |
| Fixed income: | | | | | |
| Pooled funds | — | 24 | — | — | 24 |
| Cash equivalents and other | 2 | — | — | 1 | 3 |
| Total | $ 5 | $ 115 | $ — | $ 1 | $ 121 |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

**NOTES (continued)**
**Southern Company and Subsidiary Companies 2017 Annual Report**

| As of December 31, 2016: | Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Net Asset Value as a Practical Expedient (NAV) | Total |
|---|---|---|---|---|---|
| | *(in millions)* | | | | |
| Assets: | | | | | |
| Domestic equity (*) | $ 3 | $ 58 | $ — | $ — | $ 61 |
| International equity (*) | — | 18 | — | — | 18 |
| Fixed income: | | | | | |
| Pooled funds | — | 23 | — | — | 23 |
| Cash equivalents and other | 1 | — | — | 2 | 3 |
| Total | $ 4 | $ 99 | $ — | $ 2 | $ 105 |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

The composition of Southern Company Gas' other postretirement benefit plan assets as of December 31, 2017 and 2016 , along with the targets, is presented below:

| | Target | **2017** | 2016 |
|---|---|---|---|
| **Other postretirement benefit plan assets:** | | | |
| Equity | 72% | **76%** | 74% |
| Fixed Income | 24 | **20** | 23 |
| Cash | 1 | **2** | 1 |
| Other | 3 | **2** | 2 |
| Total | 100% | **100%** | 100% |

**Employee Savings Plan**

Southern Company and its subsidiaries also sponsor 401(k) defined contribution plans covering substantially all employees and provide matching contributions up to specified percentages of an employee's eligible pay. Total matching contributions made to the plans for 2017 , 2016 , and 2015 were $118 million , $105 million , and $92 million , respectively.

## 3. CONTINGENCIES AND REGULATORY MATTERS

### General Litigation Matters

On January 20, 2017, a purported securities class action complaint was filed against Southern Company, certain of its officers, and certain former Mississippi Power officers in the U.S. District Court for the Northern District of Georgia, Atlanta Division, by Monroe County Employees' Retirement System on behalf of all persons who purchased shares of Southern Company's common stock between April 25, 2012 and October 29, 2013. The complaint alleges that Southern Company, certain of its officers, and certain former Mississippi Power officers made materially false and misleading statements regarding the Kemper County energy facility in violation of certain provisions under the Securities Exchange Act of 1934, as amended. The complaint seeks, among other things, compensatory damages and litigation costs and attorneys' fees. On June 12, 2017, the plaintiffs filed an amended complaint that provided additional detail about their claims, increased the purported class period by one day, and added certain other former Mississippi Power officers as defendants. On July 27, 2017, the defendants filed a motion to dismiss the plaintiffs' amended complaint with prejudice, to which the plaintiffs filed an opposition on September 11, 2017.

On February 27, 2017, Jean Vineyard filed a shareholder derivative lawsuit in the U.S. District Court for the Northern District of Georgia that names as defendants Southern Company, certain of its directors, certain of its officers, and certain former Mississippi Power officers. The complaint alleges that the defendants caused Southern Company to make false or misleading statements regarding the Kemper County energy facility cost and schedule. Further, the complaint alleges that the defendants were unjustly enriched and caused the waste of corporate assets. The plaintiff seeks to recover, on behalf of Southern Company, unspecified actual damages and, on her own behalf, attorneys' fees and costs in bringing the lawsuit. The plaintiff also seeks certain changes to Southern Company's corporate governance and internal processes. On March 27, 2017, the court deferred this lawsuit until 30 days after certain further action in the purported securities class action complaint discussed above.

On May 15, 2017, Helen E. Piper Survivor's Trust filed a shareholder derivative lawsuit in the Superior Court of Gwinnett County, State of Georgia and, on May 31, 2017, Judy Mesirov filed a shareholder derivative lawsuit in the U.S. District Court for the Northern District of Georgia. Each of these lawsuits names as defendants Southern Company, certain of its directors, certain of its officers, and certain former Mississippi Power officers. Each complaint alleges that the individual defendants, among other things, breached their fiduciary duties in connection with schedule delays and cost overruns associated with the construction of the Kemper County energy facility. Each complaint further alleges that the individual defendants authorized or failed to correct false and misleading statements regarding the Kemper County energy facility schedule and cost and failed to implement necessary internal controls to prevent harm to Southern Company. Each plaintiff seeks to recover, on behalf of Southern Company, unspecified actual damages and disgorgement of profits and, on its behalf, attorneys' fees and costs in bringing the lawsuit. Each plaintiff also seeks certain unspecified changes to Southern Company's corporate governance and internal processes. On August 15, 2017, these two shareholder derivative lawsuits were consolidated in the U.S. District Court for the Northern District of Georgia and the court deferred the consolidated case until 30 days after certain further action in the purported securities class action complaint discussed above.

Southern Company believes these legal challenges have no merit; however, an adverse outcome in any of these proceedings could have an impact on Southern Company's results of operations, financial condition, and liquidity. Southern Company will vigorously defend itself in these matters, the ultimate outcome of which cannot be determined at this time.

Southern Company and its subsidiaries are subject to certain claims and legal actions arising in the ordinary course of business. In addition, the business activities of Southern Company's subsidiaries are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as standards for air, water, land, and protection of other natural resources, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by $CO_2$ and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. The ultimate outcome of such pending or potential litigation against Southern Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Southern Company's financial statements.

**Environmental Matters**

***Environmental Remediation***

The Southern Company system must comply with environmental laws and regulations governing the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Southern Company system could incur substantial costs to clean up affected sites. The traditional electric operating companies and the natural gas distribution utilities conduct studies to determine the extent of any required cleanup and have recognized the estimated costs to clean up known impacted sites in the financial statements. A liability for environmental remediation costs is recognized only when a loss is determined to be probable and reasonably estimable. The traditional electric operating companies and the natural gas distribution utilities in Illinois, New Jersey, Georgia, and Florida have all received authority from their respective state PSCs or other applicable state regulatory agencies to recover approved environmental compliance costs through regulatory mechanisms. These regulatory mechanisms are adjusted annually or as necessary within limits approved by the state PSCs or other applicable state regulatory agencies.

Georgia Power's environmental remediation liability as of December 31, 2017 and 2016 was $22 million and $17 million , respectively. Georgia Power has been designated or identified as a potentially responsible party at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act, and assessment and potential cleanup of such sites is expected.

Gulf Power's environmental remediation liability includes estimated costs of environmental remediation projects of approximately $52 million and $44 million as of December 31, 2017 and 2016 , respectively. These estimated costs primarily relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at Gulf Power's substations. The schedule for completion of the remediation projects is subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through Gulf Power's environmental cost recovery clause; therefore, these liabilities have no impact on net income.

Southern Company Gas' environmental remediation liability as of December 31, 2017 and 2016 was $388 million and $426 million , respectively, based on the estimated cost of environmental investigation and remediation associated with known current and former manufactured gas plant operating sites. These environmental remediation expenditures are recoverable from customers through rate mechanisms approved by the applicable state regulatory agencies of the natural gas distribution utilities, with the exception of one site representing $2 million of the total accrued remediation costs.

The ultimate outcome of these matters cannot be determined at this time; however, as a result of the regulatory treatment for environmental remediation expenses described above, the final disposition of these matters is not expected to have a material impact on Southern Company's financial statements.

**Nuclear Fuel Disposal Costs**

Acting through the DOE and pursuant to the Nuclear Waste Policy Act of 1982, the U.S. government entered into contracts with Alabama Power and Georgia Power that require the DOE to dispose of spent nuclear fuel and high level radioactive waste generated at Plants Hatch and Farley and Plant Vogtle Units 1 and 2 beginning no later than January 31, 1998. The DOE has yet to commence the performance of its contractual and statutory obligation to dispose of spent nuclear fuel. Consequently, Alabama Power and Georgia Power pursued and continue to pursue legal remedies against the U.S. government for its partial breach of contract.

In 2014, the Court of Federal Claims entered a judgment in favor of Georgia Power and Alabama Power in their spent nuclear fuel lawsuit seeking damages for the period from January 1, 2005 through December 31, 2010. In 2015, Georgia Power recovered approximately $18 million , based on its ownership interests, which was credited to accounts where the original costs were charged, and used to reduce rate base, fuel, and cost of service for the benefit of customers. Also in 2015, Alabama Power recovered approximately $26 million , which was applied to reduce the cost of service for the benefit of customers.

In 2014, Alabama Power and Georgia Power filed lawsuits against the U.S. government for the costs of continuing to store spent nuclear fuel at Plants Farley and Hatch and Plant Vogtle Units 1 and 2 for the period from January 1, 2011 through December 31, 2013. The damage period was subsequently extended to December 31, 2014. On October 10, 2017, Alabama Power and Georgia Power filed additional lawsuits against the U.S. government in the Court of Federal Claims for the costs of continuing to store spent nuclear fuel at Plants Farley and Hatch and Plant Vogtle Units 1 and 2 for the period from January 1, 2015 through December 31, 2017. Damages will continue to accumulate until the issue is resolved or storage is provided. No amounts have been recognized in the financial statements as of December 31, 2017 for any potential recoveries from the pending lawsuits. The final outcome of these matters cannot be determined at this time. However, Alabama Power and Georgia Power expect to credit any recoveries back for the benefit of customers in accordance with direction from their respective PSC and, therefore, no material impact on Southern Company's net income is expected.

On-site dry spent fuel storage facilities are operational at all three plants and can be expanded to accommodate spent fuel through the expected life of each plant.

**FERC Matters**

***Market-Based Rate Authority***

The traditional electric operating companies and Southern Power have authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In 2015, the FERC issued an order finding that the traditional electric operating companies' and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The FERC directed the traditional electric operating companies and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional electric operating companies and Southern Power filed a request for rehearing and filed their response with the FERC in 2015.

In December 2016, the traditional electric operating companies and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. On May 17, 2017, the FERC accepted the traditional electric operating companies' and Southern Power's compliance filing accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

On October 25, 2017, the FERC issued an order in response to the traditional electric operating companies' and Southern Power's June 29, 2017 triennial updated market power analysis. The FERC directed the traditional electric operating companies and Southern Power to show cause within 60 days why market-based rate authority should not be revoked in certain areas adjacent to the area presently under mitigation in accordance with the February 2, 2017 order or to provide a mitigation plan to further address market power concerns. On November 10, 2017, the traditional electric operating companies and Southern Power responded to the FERC and proposed to resolve matters by applying the alternative mitigation authorized by the February 2, 2017 order to the adjacent areas made the subject of the October 25, 2017 order.

The ultimate outcome of these matters cannot be determined at this time.

**Regulatory Matters**

***Alabama Power***

*Rate RSE*

The Alabama PSC has adopted Rate RSE that provides for periodic annual adjustments based upon Alabama Power's projected weighted cost of equity (WCE) compared to an allowable range. Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Retail rates remain unchanged when the WCE ranges between 5.75% and 6.21% with an adjusting point of 5.98% and eligibility for a performance-based adder of seven basis points, or 0.07% , to the WCE adjusting point if Alabama Power (i) has an "A" credit rating equivalent with at least one of the recognized rating agencies or (ii) is in the top one-third of a designated customer value benchmark survey. Rate RSE adjustments for any two -year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0% . If Alabama Power's actual retail return is above the allowed WCE range, the excess will be refunded to customers unless otherwise directed by the Alabama PSC; however, there is no provision for additional customer billings should the actual retail return fall below the WCE range.

At December 31, 2016, Alabama Power's retail return exceeded the allowed WCE range which resulted in Alabama Power establishing a $73 million Rate RSE refund liability. In accordance with an Alabama PSC order issued on February 14, 2017, Alabama Power applied the full amount of the refund to reduce the under recovered balance of Rate CNP PPA as discussed further below.

Effective in January 2017, Rate RSE increased 4.48% , or $245 million annually. At December 31, 2017, Alabama Power's actual retail return was within the allowed WCE range. On December 1, 2017, Alabama Power made its required annual Rate RSE submission to the Alabama PSC of projected data for calendar year 2018. Projected earnings were within the specified range; therefore, retail rates under Rate RSE remained unchanged for 2018.

In conjunction with Rate RSE, Alabama Power has an established retail tariff that provides for an adjustment to customer billings to recognize the impact of a change in the statutory income tax rate. As a result of Tax Reform Legislation, the application of this tariff would reduce annual retail revenue by approximately $250 million over the remainder of 2018. The ultimate outcome of this matter cannot be determined at this time.

*Rate CNP PPA*

Alabama Power's retail rates, approved by the Alabama PSC, provide for adjustments under Rate CNP to recognize the placing of new generating facilities into retail service. Alabama Power may also recover retail costs associated with certificated PPAs under Rate CNP PPA. On March 7, 2017, the Alabama PSC issued a consent order that Alabama Power leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2017 through March 31, 2018. No adjustment to Rate CNP PPA is expected in 2018. As of December 31, 2017 and 2016 , Alabama Power had an under recovered Rate CNP PPA balance of $12 million and $142 million , respectively, which is included in deferred under recovered regulatory clause revenues in the balance sheet.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, Alabama Power eliminated the under recovered balance in Rate CNP PPA at December 31, 2016, which totaled approximately $142 million . As discussed herein under "Rate RSE," Alabama Power utilized the full amount of its $73 million Rate RSE refund liability to reduce the amount of the Rate CNP PPA under recovery and reclassified the remaining $69 million to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of Alabama Power's next depreciation study, which is expected to occur within the next two to four years . Alabama Power's current depreciation study became effective January 1, 2017.

*Rate CNP Compliance*

Rate CNP Compliance allows for the recovery of Alabama Power's retail costs associated with laws, regulations, and other such mandates directed at the utility industry involving the environment, security, reliability, safety, sustainability, or similar considerations impacting Alabama Power's facilities or operations. Rate CNP Compliance is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Compliance costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. Revenues for Rate CNP Compliance, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will have no significant effect on revenues or net income, but will affect annual cash flow. Changes in Rate CNP Compliance-related operations and maintenance expenses and depreciation generally will have no effect on net income.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, Alabama Power reclassified $36 million of its under recovered balance in Rate CNP Compliance to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of Alabama Power's next depreciation study, which is expected to occur within the next two to four years . Alabama Power's current depreciation study became effective January 1, 2017.

On December 5, 2017, the Alabama PSC issued a consent order that Alabama Power leave in effect for 2018 the factors associated with Alabama Power's compliance costs for the year 2017, with any under-collected amount for prior years deemed recovered before any current year amounts. Any under recovered amounts associated with 2018 will be reflected in the 2019 filing. As of December 31, 2017 and 2016 , Alabama Power had a deferred under recovered regulatory clause revenues balance of $17 million and $9 million , respectively.

*Rate ECR*

Alabama Power has established energy cost recovery rates under Alabama Power's Rate ECR as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. Alabama Power, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on Southern Company's net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per KWH.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, Alabama Power reclassified $36 million of its under recovered balance in Rate ECR to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of Alabama Power's next depreciation study, which is expected to occur within the next two to four years . Alabama Power's current depreciation study became effective January 1, 2017.

On December 5, 2017, the Alabama PSC issued a consent order that Alabama Power leave in effect for 2018 the energy cost recovery rates which began in 2017. Therefore, the Rate ECR factor as of January 1, 2018 remained at 2.015 cents per KWH. The rate will return to 5.910 cents per KWH in 2019, absent a further order from the Alabama PSC.

At December 31, 2017 , Alabama Power's under recovered fuel costs totaled $25 million , which is included in other regulatory assets, current. At December 31, 2016, Alabama Power had an over recovered fuel balance of $76 million , which was included in other regulatory liabilities, current. These classifications are based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any recovery or return of fuel costs.

*Rate NDR*

Based on an order from the Alabama PSC, Alabama Power maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate NDR charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. When the reserve balance falls below $50 million , a reserve establishment charge will be activated (and the on-going reserve maintenance charge concurrently suspended) until the reserve balance reaches $75 million . The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24 -month period. The Alabama PSC order gives Alabama Power authority to record a deficit balance in the NDR when costs of storm damage exceed any established reserve balance. Absent further Alabama PSC approval, the maximum total Rate NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account. Alabama Power has the authority, based on an order from the Alabama PSC, to accrue certain additional amounts as circumstances warrant. The order allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million . Alabama Power may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance Alabama Power's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear. No such accruals were recorded or designated in any period presented.

In December 2017, the reserve maintenance charge was suspended and the reserve establishment charge was activated as a result of the NDR balance falling below $50 million . Alabama Power expects to collect approximately $16 million annually until the reserve balance is restored to $75 million . The NDR balance at December 31, 2017 was $38 million .

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

*Environmental Accounting Order*

Based on an order from the Alabama PSC, Alabama Power is allowed to establish a regulatory asset to record the unrecovered investment costs, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure associated with future unit retirements caused by environmental regulations. The regulatory asset will be amortized and recovered over the affected unit's remaining useful life, as established prior to the decision regarding early retirement through Rate CNP Compliance.

Alabama Power retired Plant Gorgas Units 6 and 7 ( 200 MWs) and Plant Barry Unit 3 ( 225 MWs) in 2015. Additionally, Alabama Power ceased using coal at Plant Barry Units 1 and 2 ( 250 MWs) in 2015, but such units remain available on a limited basis with natural gas as the fuel source. In April 2016, Alabama Power also ceased using coal at Plant Greene County Units 1 and 2 ( 300 MWs representing Alabama Power's ownership interest) and began operating Units 1 and 2 solely on natural gas in June 2016 and July 2016, respectively.

In accordance with this accounting order from the Alabama PSC, Alabama Power transferred the unrecovered plant asset balances to regulatory assets at their respective retirement dates. These regulatory assets are being amortized and recovered through Rate CNP Compliance over the units' remaining useful lives, as established prior to the decision for retirement; therefore, these decisions associated with coal operations had no significant impact on Southern Company's financial statements.

***Georgia Power***

*Rate Plans*

Pursuant to the terms and conditions of a settlement agreement related to Southern Company's acquisition of Southern Company Gas approved by the Georgia PSC in April 2016, the 2013 ARP will continue in effect until December 31, 2019, and Georgia Power will be required to file its next base rate case by July 1, 2019. Furthermore, through December 31, 2019, Georgia Power and Atlanta Gas Light Company each will retain their respective merger savings, net of transition costs, as defined in the settlement agreement; through December 31, 2022, such net merger savings applicable to each will be shared on a 60 / 40 basis with their respective customers; thereafter, all merger savings will be retained by customers.

In accordance with the 2013 ARP, the Georgia PSC approved increases to tariffs effective January 1, 2016 as follows: (1) traditional base tariff rates by approximately $49 million ; (2) Environmental Compliance Cost Recovery tariff by approximately $75 million ; (3) Demand-Side Management tariffs by approximately $3 million ; and (4) Municipal Franchise Fee tariff by approximately $13 million , for a total increase in base revenues of approximately $140 million . There were no changes to these tariffs in 2017.

Under the 2013 ARP, Georgia Power's retail ROE is set at 10.95% and earnings are evaluated against a retail ROE range of 10.00% to 12.00% . Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. In 2015, Georgia Power's retail ROE was within the allowed retail ROE range. In 2016, Georgia Power's retail ROE exceeded 12.00% , and Georgia Power will refund to retail customers approximately $44 million in 2018, as approved by the Georgia PSC on January 16, 2018. In 2017, Georgia Power's retail ROE was within the allowed retail ROE range, subject to review and approval by the Georgia PSC.

On January 19, 2018, the Georgia PSC issued an order on the Tax Reform Legislation, which was amended on February 16, 2018 (Tax Order). In accordance with the Tax Order, Georgia Power is required to submit its analysis of the Tax Reform Legislation and related recommendations to address the related impacts on Georgia Power 's cost of service and annual revenue requirements by March 6, 2018. The ultimate outcome of this matter cannot be determined at this time.

*Integrated Resource Plan*

In July 2016, the Georgia PSC approved Georgia Power's triennial Integrated Resource Plan (2016 IRP) including the decertification and retirement of Plant Mitchell Units 3, 4A, and 4B ( 217 MWs) and Plant Kraft Unit 1 ( 17 MWs), as well as the decertification of the Intercession City unit ( 143 MWs total capacity). In August 2016, the Plant Mitchell and Plant Kraft units were retired and Georgia Power sold its 33% ownership interest in the Intercession City unit to Duke Energy Florida, LLC.

Additionally, the Georgia PSC approved Georgia Power's environmental compliance strategy and related expenditures proposed in the 2016 IRP, including measures taken to comply with existing government-imposed environmental mandates, subject to limits on expenditures for Plant McIntosh Unit 1 and Plant Hammond Units 1 through 4.

The Georgia PSC approved the reclassification of the remaining net book value of Plant Mitchell Unit 3 and costs associated with materials and supplies remaining at the unit retirement date to a regulatory asset. Recovery of the unit's net book value will continue through December 31, 2019, as provided in the 2013 ARP. The timing of the recovery of the remaining balance of the unit's net book value as of December 31, 2019 and costs associated with materials and supplies remaining at the unit retirement date was deferred for consideration in Georgia Power's 2019 base rate case.

The Georgia PSC also approved the Renewable Energy Development Initiative (REDI) to procure an additional 1,200 MWs of renewable resources primarily utilizing market-based prices established through a competitive bidding process with expected in-service dates between 2018 and 2021. Additionally, 200 MWs of self-build capacity for use by Georgia Power was approved, as well as consideration for no more than 200 MWs of capacity as part of a renewable commercial and industrial program.

In 2017, Georgia Power filed for and received certification for 510 MWs of REDI utility-scale PPAs for solar generation resources, which are expected to be in operation by the end of 2019. Georgia Power also filed for and received approval to develop several solar generation projects to fulfill the approved self-build capacity.

In the 2016 IRP, the Georgia PSC also approved recovery of costs up to $99 million through June 30, 2019 to preserve nuclear generation as an option at a future generation site in Stewart County, Georgia. On March 7, 2017, the Georgia PSC approved Georgia Power's decision to suspend work at the site due to changing economics, including lower load forecasts and fuel costs. The timing of recovery for costs incurred of approximately $50 million is expected to be determined by the Georgia PSC in a future Georgia Power rate case.

*Fuel Cost Recovery*

Georgia Power has established fuel cost recovery rates approved by the Georgia PSC. In 2015, the Georgia PSC approved Georgia Power's request to lower annual billings by approximately $350 million effective January 1, 2016. In May 2016, the Georgia PSC approved Georgia Power's request to further lower annual billings under an interim fuel rider by approximately $313 million effective June 1, 2016, which expired on December 31, 2017. The Georgia PSC will review Georgia Power's cumulative over or under recovered fuel balance no later than September 1, 2018 and evaluate the need to file a fuel case unless Georgia Power deems it necessary to file a fuel case at an earlier time. Georgia Power continues to be allowed to adjust its fuel cost recovery rates under an interim fuel rider prior to the next fuel case if the under recovered fuel balance exceeds $200 million .

Georgia Power's fuel cost recovery mechanism includes costs associated with a natural gas hedging program, as revised and approved by the Georgia PSC, allowing the use of an array of derivative instruments within a 48 -month time horizon.

Georgia Power's under recovered fuel balance totaled $165 million at December 31, 2017 and is included in current assets. At December 31, 2016 , Georgia Power's over recovered fuel balance totaled $84 million and is included in other regulatory liabilities, current.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on Southern Company's revenues or net income, but will affect cash flow.

*Storm Damage Recovery*

Georgia Power is accruing $30 million annually through December 31, 2019, as provided in the 2013 ARP, for incremental operating and maintenance costs of damage from major storms to its transmission and distribution facilities. Hurricanes Irma and Matthew caused significant damage to Georgia Power's transmission and distribution facilities during September 2017 and

October 2016, respectively. The incremental restoration costs related to these hurricanes deferred in Georgia Power's regulatory asset for storm damage totaled approximately $260 million . The rate of storm damage cost recovery is expected to be adjusted as part of Georgia Power's next base rate case required to be filed by July 1, 2019. As a result of this regulatory treatment, costs related to storms are not expected to have a material impact on Southern Company's financial statements.

At December 31, 2017 and December 31, 2016 , the total balance in Georgia Power's regulatory asset related to storm damage was $333 million and $206 million , respectively, with approximately $30 million included in other regulatory assets, current for both years and approximately $303 million and $176 million included in other regulatory assets, deferred, respectively.

***Gulf Power***

*Retail Base Rate Cases*

In 2013, the Florida PSC approved a settlement agreement related to Gulf Power's 2013 retail base rate case that authorized Gulf Power to reduce depreciation and record a regulatory asset up to $62.5 million from January 2014 through June 2017. In any given month, such depreciation reduction was not to exceed the amount necessary for the retail ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized retail ROE range then in effect. For 2014 and 2015, Gulf Power recognized reductions in depreciation of $8.4 million and $20.1 million , respectively. No net reduction in depreciation was recorded in 2016. In 2017, Gulf Power recognized the remaining $34.0 million reduction in depreciation.

On April 4, 2017, the Florida PSC approved a settlement agreement (2017 Rate Case Settlement Agreement) among Gulf Power and three intervenors with respect to Gulf Power's request in 2016 to increase retail base rates. Among the terms of the 2017 Rate Case Settlement Agreement, Gulf Power increased rates effective with the first billing cycle in July 2017 to provide an annual overall net customer impact of approximately $54.3 million . The net customer impact consisted of a $62.0 million increase in annual base revenues, less an annual purchased power capacity cost recovery clause credit for certain wholesale revenues of approximately $8 million through December 2019. In addition, Gulf Power continued its authorized retail ROE midpoint ( 10.25% ) and range ( 9.25% to 11.25% ) and is deemed to have a maximum equity ratio of 52.5% for all retail regulatory purposes. Gulf Power also began amortizing the regulatory asset associated with the investment balances remaining after the retirement of Plant Smith Units 1 and 2 ( 357 MWs) over 15 years effective January 1, 2018 and implemented new depreciation rates effective January 1, 2018. The 2017 Rate Case Settlement Agreement also resulted in a $32.5 million write-down of Gulf Power's ownership of Plant Scherer Unit 3 ( 205 MWs), which was recorded in the first quarter 2017. The remaining issues related to the inclusion of Gulf Power's investment in Plant Scherer Unit 3 in retail rates have been resolved as a result of the 2017 Rate Case Settlement Agreement, including recoverability of certain costs associated with the ongoing ownership and operation of the unit through the environmental cost recovery clause.

The 2017 Rate Case Settlement Agreement set forth a process for addressing the revenue requirement effects of the Tax Reform Legislation through a prospective change to Gulf Power's base rates. Under the terms of the 2017 Rate Case Settlement Agreement, by March 1, 2018, Gulf Power must identify the revenue requirements impacts and defer them to a regulatory asset or regulatory liability to be considered for prospective application in a change to base rates in a limited scope proceeding before the Florida PSC. In lieu of this approach, on February 14, 2018, the parties to the 2017 Rate Case Settlement Agreement filed a new stipulation and settlement agreement (2018 Tax Reform Settlement Agreement) with the Florida PSC. If approved, the 2018 Tax Reform Settlement Agreement will result in annual reductions of $18.2 million to Gulf Power's base rates and $15.6 million to Gulf Power's environmental cost recovery rates effective beginning the first calendar month following approval.

The 2018 Tax Reform Settlement Agreement also provides for a one-time refund of $69.4 million for the retail portion of unprotected (not subject to normalization) deferred tax liabilities through Gulf Power's fuel cost recovery rate over the remainder of 2018. In addition, a limited scope proceeding to address the flow back of protected deferred tax liabilities will be initiated by May 1, 2018 and Gulf Power will record a regulatory liability for the related 2018 amounts eligible to be returned to customers consistent with IRS normalization principles. Unless otherwise agreed to by the parties to the 2018 Tax Reform Settlement Agreement, amounts recorded in this regulatory liability will be refunded to retail customers in 2019 through Gulf Power's fuel cost recovery rate.

If the 2018 Tax Reform Settlement Agreement is approved, the 2017 Rate Case Settlement Agreement will be amended to increase Gulf Power's maximum equity ratio from 52.5% to 53.5% for regulatory purposes.

The ultimate outcome of these matters cannot be determined at this time.

***Mississippi Power***

On February 7, 2018, Mississippi Power revised its annual projected Performance Evaluation Plan (PEP) filing for 2018 to reflect the impacts of the Tax Reform Legislation. The revised filing requests an increase of $26 million in annual revenues, based on a performance adjusted ROE of 9.33% and an increased equity ratio of 55% . The ultimate outcome of this matter cannot be determined at this time.

***Southern Company Gas***

The natural gas distribution utilities are subject to regulation and oversight by their respective state regulatory agencies for the rates charged to their customers and other matters. These agencies approve rates designed to provide the opportunity to generate revenues to recover all prudently-incurred costs, including a return on rate base sufficient to pay interest on debt and provide a reasonable ROE.

The natural gas market for Atlanta Gas Light was deregulated in 1997. Accordingly, marketers, rather than a traditional utility, sell natural gas to end-use customers in Georgia and handle customer billing functions. Atlanta Gas Light earns revenue for its distribution services by charging rates to its customers based primarily on monthly fixed charges that are set by the Georgia PSC and adjusted periodically.

With the exception of Atlanta Gas Light, the natural gas distribution utilities are authorized by the relevant regulatory agencies in the states in which they serve to use natural gas cost recovery mechanisms that adjust rates to reflect changes in the wholesale cost of natural gas and ensure recovery of all costs prudently incurred in purchasing natural gas for customers. Natural gas cost recovery revenues are adjusted for differences in actual recoverable natural gas costs and amounts billed in current regulated rates. Changes in the billing factor will not have a significant effect on revenues or net income, but will affect cash flows. In addition to natural gas cost recovery mechanisms, there are other cost recovery mechanisms, such as regulatory riders, which vary by utility but allow recovery of certain costs, such as those related to infrastructure replacement programs, as well as environmental remediation and energy efficiency plans. See Note 1 under " Cost of Natural Gas " for additional information.

*Regulatory Infrastructure Programs*

Certain of Southern Company Gas' natural gas distribution utilities are involved in ongoing capital projects associated with infrastructure improvement programs that have been previously approved by their applicable state regulatory agencies and provide an appropriate return on invested capital. These infrastructure improvement programs are designed to update or expand the natural gas distribution systems of the natural gas distribution utilities to improve reliability and meet operational flexibility and growth. Initial program lengths range from nine to 10 years , with completion dates ranging from 2020 through 2025.

On February 21, 2017, the Georgia PSC approved a rate adjustment mechanism for Atlanta Gas Light that included the 2017 capital investment associated with a four -year extension of one of its existing infrastructure programs, with a total additional investment of $177 million through 2020.

*Base Rate Cases*

On January 31, 2018, the Illinois Commerce Commission approved a $137 million increase in Nicor Gas' annual base rate revenues, including $93 million related to the recovery of investments under Nicor Gas' infrastructure program, effective February 8, 2018, based on a ROE of 9.8% .

The Illinois Commerce Commission issued an order effective January 25, 2018 that requires utilities in the state to record the impacts of the Tax Reform Legislation, including the reduction in the corporate income tax rate to 21% and the impact of excess deferred income taxes, as a regulatory liability. On February 20, 2018, the Illinois Commerce Commission granted Nicor Gas' application for rehearing to file revised base rates and tariffs, which Nicor Gas expects to file by the end of the second quarter 2018.

On December 1, 2017, Atlanta Gas Light filed its 2018 annual rate adjustment with the Georgia PSC. If approved, Atlanta Gas Light's annual base rate revenues will increase by $22 million , effective June 1, 2018. Atlanta Gas Light will file a revised rate adjustment to incorporate the effects of the Tax Reform Legislation in the first quarter 2018. The Georgia PSC is expected to rule on the revised requested increase in the second quarter 2018.

The ultimate outcome of these matters cannot be determined at this time.

**Kemper County Energy Facility**

***Overview***

The Kemper County energy facility was designed to utilize IGCC technology with an expected output capacity of 582 MWs and to be fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by Mississippi Power and situated adjacent to the Kemper County energy facility. The mine, operated by North American Coal Corporation, started commercial operation in 2013. In connection with the Kemper County energy facility construction, Mississippi Power constructed approximately 61 miles of $CO_2$ pipeline infrastructure for the transport of captured $CO_2$ for use in enhanced oil recovery.

***Schedule and Cost Estimate***

In 2012, the Mississippi PSC issued the 2012 MPSC CPCN Order, confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper County energy facility. The certificated cost estimate of the Kemper County energy facility included in the 2012 MPSC CPCN Order was $2.4 billion , net of approximately $0.57 billion for the cost of the lignite mine and equipment, the cost of the $CO_2$ pipeline facilities, AFUDC, and certain general exceptions (Cost Cap Exceptions). The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion , with recovery of prudently-incurred costs subject to approval by the Mississippi PSC. The Kemper County energy facility was originally projected to be placed in service in May 2014. Mississippi Power placed the combined cycle and the associated common facilities portion of the Kemper County energy facility in service in August 2014.

The initial production of syngas began on July 14, 2016 for gasifier "B" and on September 13, 2016 for gasifier "A." Mississippi Power achieved integrated operation of both gasifiers on January 29, 2017, including the production of electricity from syngas in both combustion turbines. During testing, the plant produced and captured $CO_2$ , and produced sulfuric acid and ammonia, each of acceptable quality under the related off-take agreements. However, Mississippi Power experienced numerous challenges during the extended start-up process to achieve integrated operation of the gasifiers on a sustained basis. In May 2017, after achieving these milestones, Mississippi Power determined that a critical system component, the syngas coolers, would need replacement sooner than originally planned, which would require significant lead time and significant cost. In addition, the long-term natural gas price forecast had decreased significantly and the estimated cost of operating and maintaining the facility during the first five full years of operations had increased significantly since certification.

On June 21, 2017, the Mississippi PSC stated its intent to issue an order (which occurred on July 6, 2017) directing Mississippi Power to pursue a settlement under which the Kemper County energy facility would be operated as a natural gas plant, rather than an IGCC plant, and address all issues associated with the Kemper County energy facility (Kemper Settlement Order). The Kemper Settlement Order established a new docket for the purposes of pursuing a global settlement of the related costs (Kemper Settlement Docket). On June 28, 2017, Mississippi Power notified the Mississippi PSC that it would begin a process to suspend operations and start-up activities on the gasifier portion of the Kemper County energy facility, given the uncertainty as to its future. On February 6, 2018, the Mississippi PSC voted to approve a settlement agreement related to cost recovery for the Kemper County energy facility among Mississippi Power, the MPUS, and certain intervenors (Kemper Settlement Agreement).

At the time of project suspension in June 2017, the total cost estimate for the Kemper County energy facility was approximately $7.38 billion , including approximately $5.95 billion of costs subject to the construction cost cap, and was net of the $137 million in additional grants from the DOE for the Kemper County energy facility. In the aggregate, Mississippi Power had recorded charges to income of $3.07 billion ( $1.89 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through May 31, 2017.

Given the Mississippi PSC's stated intent regarding no further rate increase for the Kemper County energy facility and the subsequent suspension, cost recovery of the gasifier portions became no longer probable; therefore, Mississippi Power recorded an additional charge to income in June 2017 of $2.8 billion ( $2.0 billion after tax), which included estimated costs associated with the gasifier portions of the plant and lignite mine. During the third and fourth quarters of 2017, Mississippi Power recorded charges to income of $242 million ( $206 million after tax), including $164 million for ongoing project costs, estimated mine and gasifier-related costs, and certain termination costs during the suspension period prior to conclusion of the Kemper Settlement Docket, as well as the charge associated with the Kemper Settlement Agreement discussed below. Additional pre-tax cancellation costs, including mine and plant closure and contract termination costs, currently estimated at approximately $50 million to $100 million (excluding salvage), are expected to be incurred in 2018. Mississippi Power has begun efforts to dispose of or abandon the mine and gasifier-related assets.

***Rate Recovery***

*Kemper Settlement Agreement*

On February 6, 2018, the Mississippi PSC voted to approve the Kemper Settlement Agreement. The Kemper Settlement Agreement provides for an annual revenue requirement of approximately $99.3 million for costs related to the Kemper County energy facility, which includes the impact of Tax Reform Legislation. The revenue requirement is based on (i) a fixed ROE for 2018 of 8.6% excluding any performance adjustment, (ii) a ROE for 2019 calculated in accordance with PEP, excluding the performance adjustment, (iii) for future years, a performance-based ROE calculated pursuant to PEP, and (iv) amortization periods for the related regulatory assets and liabilities of eight years and six years, respectively. The revenue requirement also reflects a disallowance related to a portion of Mississippi Power's investment in the Kemper County energy facility requested for inclusion in rate base, which was recorded in the fourth quarter 2017 as an additional charge to income of approximately $78 million ( $85 million net of accumulated depreciation of $7 million ) pre-tax ( $48 million after tax).

Under the Kemper Settlement Agreement, retail customer rates will reflect a reduction of approximately $26.8 million annually and include no recovery for costs associated with the gasifier portion of the Kemper County energy facility in 2018 or at any future date. On February 12, 2018, Mississippi Power made the required compliance filing with the Mississippi PSC. The Kemper Settlement Agreement also requires (i) the CPCN for the Kemper County energy facility to be modified to limit it to natural gas combined cycle operation and (ii) Mississippi Power to file a reserve margin plan with the Mississippi PSC by August 2018.

As of December 31, 2017, the balances associated with the Kemper County energy facility regulatory assets and liabilities were $114 million and $26 million , respectively.

As a result of the Mississippi PSC order on February 6, 2018, rate recovery for the Kemper County energy facility is resolved, subject to any future legal challenges.

*2015 Rate Case*

On December 3, 2015, the Mississippi PSC issued the In-Service Asset Rate Order regarding the Kemper County energy facility assets that were commercially operational and currently providing service to customers (the transmission facilities, combined cycle, natural gas pipeline, and water pipeline) and other related costs. The In-Service Asset Rate Order provided for retail rate recovery of an annual revenue requirement of approximately $126 million , based on Mississippi Power's actual average capital structure, with a maximum common equity percentage of 49.733% , a 9.225% return on common equity, and actual embedded interest costs. The In-Service Asset Rate Order also included a prudence finding of all costs in the stipulated revenue requirement calculation for the in-service assets.

In connection with the implementation of the In-Service Asset Rate Order and wholesale rates, Mississippi Power began expensing certain ongoing project costs and certain retail debt carrying costs that previously were deferred and began amortizing certain regulatory assets associated with assets placed in service and consulting and legal fees over periods ranging from two years to 10 years. On July 6, 2017, the Mississippi PSC issued an order requiring Mississippi Power to establish a regulatory liability account to maintain current rates related to the Kemper County energy facility following the July 2017 completion of the amortization period for certain of these regulatory assets.

***Lignite Mine and $CO_2$ Pipeline Facilities***

Mississippi Power owns the lignite mine and equipment and mineral reserves located around the Kemper County energy facility site. The mine started commercial operation in June 2013.

In 2010, Mississippi Power executed a 40 -year management fee contract with Liberty Fuels Company, LLC (Liberty Fuels), a wholly-owned subsidiary of The North American Coal Corporation, which developed, constructed, and is responsible for the mining operations through the end of the mine reclamation. As the mining permit holder, Liberty Fuels has a legal obligation to perform mine reclamation and Mississippi Power has a contractual obligation to fund all reclamation activities. Mississippi Power expects mine reclamation to begin in 2018. In addition to the obligation to fund the reclamation activities, Mississippi Power provided working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses.

In addition, Mississippi Power constructed the $CO_2$ pipeline for the planned transport of captured $CO_2$ for use in enhanced oil recovery and entered into an agreement with Denbury Onshore (Denbury) to purchase the captured $CO_2$ . Denbury has the right to terminate the contract at any time because Mississippi Power did not place the Kemper IGCC in service by July 1, 2017.

The ultimate outcome of these matters cannot be determined at this time.

***Litigation***

On April 26, 2016, a complaint against Mississippi Power was filed in Harrison County Circuit Court (Circuit Court) by Biloxi Freezing & Processing Inc., Gulfside Casino Partnership, and John Carlton Dean, which was amended and refiled on July 11, 2016 to include, among other things, Southern Company as a defendant. The individual plaintiff alleges that Mississippi Power and Southern Company violated the Mississippi Unfair Trade Practices Act. All plaintiffs have alleged that Mississippi Power and Southern Company concealed, falsely represented, and failed to fully disclose important facts concerning the cost and schedule of the Kemper County energy facility and that these alleged breaches have unjustly enriched Mississippi Power and Southern Company. The plaintiffs seek unspecified actual damages and punitive damages; ask the Circuit Court to appoint a receiver to oversee, operate, manage, and otherwise control all affairs relating to the Kemper County energy facility; ask the Circuit Court to revoke any licenses or certificates authorizing Mississippi Power or Southern Company to engage in any business related to the Kemper County energy facility in Mississippi; and seek attorney's fees, costs, and interest. The plaintiffs also seek an injunction to prevent any Kemper County energy facility costs from being charged to customers through electric rates. On June 23, 2017, the Circuit Court ruled in favor of motions by Southern Company and Mississippi Power and dismissed the case. On July 7, 2017, the plaintiffs filed notice of an appeal. Southern Company believes this legal challenge has no merit; however, an adverse outcome in this proceeding could have a material impact on Southern Company's results of operations, financial condition, and liquidity. Southern Company intends to vigorously defend itself in this matter and the ultimate outcome of this matter cannot be determined at this time.

On June 9, 2016, Treetop, Greenleaf $CO_2$ Solutions, LLC (Greenleaf), Tenrgys, LLC, Tellus Energy, LLC, WCOA, LLC, and Tellus Operating Group filed a complaint against Mississippi Power, Southern Company, and SCS in the state court in Gwinnett County, Georgia. The complaint related to the cancelled $CO_2$ contract with Treetop and alleged fraudulent misrepresentation, fraudulent concealment, civil conspiracy, and breach of contract on the part of Mississippi Power, Southern Company, and SCS and sought compensatory damages of $100 million , as well as unspecified punitive damages. Southern Company, Mississippi Power, and SCS moved to compel arbitration pursuant to the terms of the $CO_2$ contract, which the court granted on May 4, 2017. On June 28, 2017, Treetop, Greenleaf, Tenrgys, LLC, Tellus Energy, LLC, WCOA, LLC, and Tellus Operating Group filed a claim for arbitration requesting $500 million in damages. On December 28, 2017, Mississippi Power reached a settlement agreement with Treetop, Greenleaf, Tenrgys, LLC, Tellus Energy, LLC, WCOA, LLC, and Tellus Operating Group and the arbitration was dismissed.

**Nuclear Construction**

***Project Status***

In 2009, the Georgia PSC certified construction of Plant Vogtle Units 3 and 4. In 2012, the NRC issued the related combined construction and operating licenses, which allowed full construction of the two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities to begin. Until March 2017, construction on Plant Vogtle Units 3 and 4 continued under the Vogtle 3 and 4 Agreement, which was a substantially fixed price agreement. On March 29, 2017, the EPC Contractor filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code.

In connection with the EPC Contractor's bankruptcy filing, Georgia Power, acting for itself and as agent for the Vogtle Owners, entered into the Interim Assessment Agreement with the EPC Contractor to allow construction to continue. The Interim Assessment Agreement expired on July 27, 2017 when the Vogtle Services Agreement became effective. In August 2017, following completion of comprehensive cost to complete and cancellation cost assessments, Georgia Power filed its seventeenth VCM report with the Georgia PSC, which included a recommendation to continue construction of Plant Vogtle Units 3 and 4, with Southern Nuclear serving as project manager and Bechtel serving as the primary construction contractor. On December 21, 2017, the Georgia PSC approved Georgia Power's recommendation to continue construction.

Georgia Power expects Plant Vogtle Units 3 and 4 to be placed in service by November 2021 and November 2022, respectively. Georgia Power's revised capital cost forecast for its 45.7% proportionate share of Plant Vogtle Units 3 and 4 is $8.8 billion ( $7.3 billion after reflecting the impact of payments received under the Guarantee Settlement Agreement and the Customer Refunds, each as defined herein). Georgia Power's CWIP balance for Plant Vogtle Units 3 and 4 was $3.3 billion at December 31, 2017 , which is net of the Guarantee Settlement Agreement payments less the Customer Refunds. Georgia Power estimates that its financing costs for construction of Plant Vogtle Units 3 and 4 will total approximately $3.1 billion , of which $1.6 billion had been incurred through December 31, 2017 .

***Vogtle 3 and 4 Agreement and EPC Contractor Bankruptcy***

In 2008, Georgia Power, acting for itself and as agent for the Vogtle Owners, entered into the Vogtle 3 and 4 Agreement. Under the terms of the Vogtle 3 and 4 Agreement, the Vogtle Owners agreed to pay a purchase price subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. Under the Toshiba Guarantee, Toshiba guaranteed certain payment obligations of the EPC Contractor, including any liability of the EPC Contractor for abandonment of work. In the first quarter 2016, Westinghouse delivered to the Vogtle Owners a total of $920 million of letters of credit from financial institutions (Westinghouse Letters of Credit) to secure a portion of the EPC Contractor's potential obligations under the Vogtle 3 and 4 Agreement.

Subsequent to the EPC Contractor bankruptcy filing, a number of subcontractors to the EPC Contractor alleged non-payment by the EPC Contractor for amounts owed for work performed on Plant Vogtle Units 3 and 4. Georgia Power, acting for itself and as agent for the Vogtle Owners, has taken actions to remove liens filed by these subcontractors through the posting of surety bonds.

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Related to such liens, certain subcontractors have filed, and additional subcontractors may file, actions against the EPC Contractor and the Vogtle Owners to preserve their payment rights with respect to such claims. All amounts associated with the removal of subcontractor liens and other EPC Contractor pre-petition accounts payable have been paid or accrued as of December 31, 2017.

On June 9, 2017, Georgia Power and the other Vogtle Owners and Toshiba entered into a settlement agreement regarding the Toshiba Guarantee (Guarantee Settlement Agreement). Pursuant to the Guarantee Settlement Agreement, Toshiba acknowledged the amount of its obligation was $3.68 billion (Guarantee Obligations), of which Georgia Power's proportionate share was approximately $1.7 billion . The Guarantee Settlement Agreement provided for a schedule of payments for the Guarantee Obligations beginning in October 2017 and continuing through January 2021. Toshiba made the first three payments as scheduled. On December 8, 2017, Georgia Power, the other Vogtle Owners, certain affiliates of the Municipal Electric Authority of Georgia (MEAG Power), and Toshiba entered into Amendment No. 1 to the Guarantee Settlement Agreement (Guarantee Settlement Agreement Amendment). The Guarantee Settlement Agreement Amendment provided that Toshiba's remaining payment obligations under the Guarantee Settlement Agreement were due and payable in full on December 15, 2017, which Toshiba satisfied on December 14, 2017. Pursuant to the Guarantee Settlement Agreement Amendment, Toshiba was deemed to be the owner of certain pre-petition bankruptcy claims of Georgia Power, the other Vogtle Owners, and certain affiliates of MEAG Power against Westinghouse, and Georgia Power and the other Vogtle Owners surrendered the Westinghouse Letters of Credit.

Additionally, on June 9, 2017, Georgia Power, acting for itself and as agent for the other Vogtle Owners, and the EPC Contractor entered into the Vogtle Services Agreement, which was amended and restated on July 20, 2017. On July 20, 2017, the bankruptcy court approved the EPC Contractor's motion seeking authorization to (i) enter into the Vogtle Services Agreement, (ii) assume and assign to the Vogtle Owners certain project-related contracts, (iii) join the Vogtle Owners as counterparties to certain assumed project-related contracts, and (iv) reject the Vogtle 3 and 4 Agreement. The Vogtle Services Agreement, and the EPC Contractor's rejection of the Vogtle 3 and 4 Agreement, became effective upon approval by the DOE on July 27, 2017. The Vogtle Services Agreement will continue until the start-up and testing of Plant Vogtle Units 3 and 4 are complete and electricity is generated and sold from both units. The Vogtle Services Agreement is terminable by the Vogtle Owners upon 30 days' written notice.

Effective October 23, 2017, Georgia Power, acting for itself and as agent for the other Vogtle Owners, entered into a construction completion agreement with Bechtel, whereby Bechtel will serve as the primary contractor for the remaining construction activities for Plant Vogtle Units 3 and 4 (Bechtel Agreement). Facility design and engineering remains the responsibility of the EPC Contractor under the Vogtle Services Agreement. The Bechtel Agreement is a cost reimbursable plus fee arrangement, whereby Bechtel will be reimbursed for actual costs plus a base fee and an at-risk fee, which is subject to adjustment based on Bechtel's performance against cost and schedule targets. Each Vogtle Owner is severally (not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to Bechtel under the Bechtel Agreement. The Vogtle Owners may terminate the Bechtel Agreement at any time for their convenience, provided that the Vogtle Owners will be required to pay amounts related to work performed prior to the termination (including the applicable portion of the base fee), certain termination-related costs, and, at certain stages of the work, the applicable portion of the at-risk fee. Bechtel may terminate the Bechtel Agreement under certain circumstances, including certain Vogtle Owner suspensions of work, certain breaches of the Bechtel Agreement by the Vogtle Owners, Vogtle Owner insolvency, and certain other events. Pursuant to the Loan Guarantee Agreement between Georgia Power and the DOE, Georgia Power is required to obtain the DOE's approval of the Bechtel Agreement prior to obtaining any further advances under the Loan Guarantee Agreement.

On November 2, 2017, the Vogtle Owners entered into an amendment to their joint ownership agreements for Plant Vogtle Units 3 and 4 (as amended, Vogtle Joint Ownership Agreements) to provide for, among other conditions, additional Vogtle Owner approval requirements. Pursuant to the Vogtle Joint Ownership Agreements, the holders of at least 90% of the ownership interests in Plant Vogtle Units 3 and 4 must vote to continue construction if certain adverse events occur, including (i) the bankruptcy of Toshiba; (ii) termination or rejection in bankruptcy of certain agreements, including the Vogtle Services Agreement or the Bechtel Agreement; (iii) the Georgia PSC or Georgia Power determines that any of Georgia Power's costs relating to the construction of Plant Vogtle Units 3 and 4 will not be recovered in retail rates because such costs are deemed unreasonable or imprudent; or (iv) an increase in the construction budget contained in the seventeenth VCM report of more than $1 billion or extension of the project schedule contained in the seventeenth VCM report of more than one year . In addition, pursuant to the Vogtle Joint Ownership Agreements, the required approval of holders of ownership interests in Plant Vogtle Units 3 and 4 is at least (i) 90% for a change of the primary construction contractor and (ii) 67% for material amendments to the Vogtle Services Agreement or agreements with Southern Nuclear or the primary construction contractor, including the Bechtel Agreement. The Vogtle Joint Ownership Agreements also confirm that the Vogtle Owners' sole recourse against Georgia Power or Southern Nuclear for any action or inaction in connection with their performance as agent for the Vogtle Owners is limited to removal of Georgia Power and/or Southern Nuclear as agent, except in cases of willful misconduct.

***Regulatory Matters***

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4 with a certified capital cost of $4.418 billion . In addition, in 2009 the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows Georgia Power to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff up to the certified capital cost of $4.418 billion . As of December 31, 2017, Georgia Power had recovered approximately $1.6 billion of financing costs. On January 30, 2018, Georgia Power filed to decrease the NCCR tariff by approximately $50 million , effective April 1, 2018, pending Georgia PSC approval. The decrease reflects the payments received under the Guarantee Settlement Agreement, refunds to customers ordered by the Georgia PSC aggregating approximately $188 million (Customer Refunds), and the estimated effects of Tax Reform Legislation. The Customer Refunds were recognized as a regulatory liability as of December 31, 2017 and will be paid in three installments of $25 to each retail customer no later than the third quarter 2018.

Georgia Power is required to file semi-annual VCM reports with the Georgia PSC by February 28 and August 31 each year. In October 2013, in connection with the eighth VCM report, the Georgia PSC approved a stipulation (2013 Stipulation) between Georgia Power and the staff of the Georgia PSC to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate in accordance with the 2009 certification order until the completion of Plant Vogtle Unit 3, or earlier if deemed appropriate by the Georgia PSC and Georgia Power.

On December 20, 2016, the Georgia PSC voted to approve a settlement agreement (Vogtle Cost Settlement Agreement) resolving certain prudency matters in connection with the fifteenth VCM report. On December 21, 2017, the Georgia PSC voted to approve (and issued its related order on January 11, 2018) certain recommendations made by Georgia Power in the seventeenth VCM report and modifying the Vogtle Cost Settlement Agreement. The Vogtle Cost Settlement Agreement, as modified by the January 11, 2018 order, resolved the following regulatory matters related to Plant Vogtle Units 3 and 4: (i) none of the $3.3 billion of costs incurred through December 31, 2015 and reflected in the fourteenth VCM report should be disallowed from rate base on the basis of imprudence; (ii) the Contractor Settlement Agreement was reasonable and prudent and none of the amounts paid pursuant to the Contractor Settlement Agreement should be disallowed from rate base on the basis of imprudence; (iii) (a) capital costs incurred up to $5.680 billion would be presumed to be reasonable and prudent with the burden of proof on any party challenging such costs, (b) Georgia Power would have the burden to show that any capital costs above $5.680 billion were prudent, and (c) a revised capital cost forecast of $7.3 billion (after reflecting the impact of payments received under the Guarantee Settlement Agreement and Customer Refunds) is found reasonable; (iv) construction of Plant Vogtle Units 3 and 4 should be completed, with Southern Nuclear serving as project manager and Bechtel as primary contractor; (v) approved and deemed reasonable Georgia Power's revised schedule placing Plant Vogtle Units 3 and 4 in service in November 2021 and November 2022, respectively; (vi) confirmed that the revised cost forecast does not represent a cost cap and that prudence decisions on cost recovery will be made at a later date, consistent with applicable Georgia law; (vii) reduced the ROE used to calculate the NCCR tariff (a) from 10.95% (the ROE rate setting point authorized by the Georgia PSC in the 2013 ARP) to 10.00% effective January 1, 2016, (b) from 10.00% to 8.30% , effective January 1, 2020, and (c) from 8.30% to 5.30% , effective January 1, 2021 (provided that the ROE in no case will be less than Georgia Power's average cost of long-term debt); (viii) reduced the ROE used for AFUDC equity for Plant Vogtle Units 3 and 4 from 10.00% to Georgia Power's average cost of long-term debt, effective January 1, 2018; and (ix) agreed that upon Unit 3 reaching commercial operation, retail base rates would be adjusted to include carrying costs on those capital costs deemed prudent in the Vogtle Cost Settlement Agreement. The January 11, 2018 order also stated that if Plant Vogtle Units 3 and 4 are not commercially operational by June 1, 2021 and June 1, 2022, respectively, the ROE used to calculate the NCCR tariff will be further reduced by 10 basis points each month (but not lower than Georgia Power's average cost of long-term debt) until the respective unit is commercially operational. The ROE reductions negatively impacted earnings by approximately $20 million in 2016 and $25 million in 2017 and are estimated to have negative earnings impacts of approximately $120 million in 2018 and an aggregate of $585 million from 2019 to 2022. In its January 11, 2018 order, the Georgia PSC stated if other certain conditions and assumptions upon which Georgia Power's seventeenth VCM report are based do not materialize, both Georgia Power and the Georgia PSC reserve the right to reconsider the decision to continue construction.

On February 12, 2018, Georgia Interfaith Power & Light, Inc. and Partnership for Southern Equity, Inc. filed a petition appealing the Georgia PSC's January 11, 2018 order with the Fulton County Superior Court. Georgia Power believes the appeal has no merit; however, an adverse outcome in this appeal could have a material impact on Southern Company's results of operations, financial condition, and liquidity.

The IRS allocated PTCs to each of Plant Vogtle Units 3 and 4, which originally required the applicable unit to be placed in service before 2021. Under the Bipartisan Budget Act of 2018, Plant Vogtle Units 3 and 4 continue to qualify for PTCs. The nominal value of Georgia Power's portion of the PTCs is approximately $500 million per unit.

In its January 11, 2018 order, the Georgia PSC also approved $542 million of capital costs incurred during the seventeenth VCM reporting period (January 1, 2017 to June 30, 2017). The Georgia PSC has approved seventeen VCM reports covering the periods through June 30, 2017 , including total construction capital costs incurred through that date of $4.4 billion . Georgia Power expects to file its eighteenth VCM report on February 28, 2018 requesting approval of approximately $450 million of construction capital costs (before payments received under the Guarantee Settlement Agreement and the Customer Refunds) incurred from July 1, 2017 through December 31, 2017. Georgia Power's CWIP balance for Plant Vogtle Units 3 and 4 was approximately $4.8 billion as of December 31, 2017 , or $3.3 billion net of payments received under the Guarantee Settlement Agreement and the Customer Refunds.

The ultimate outcome of these matters cannot be determined at this time.

### *Cost and Schedule*

Georgia Power's approximate proportionate share of the remaining estimated capital cost to complete Plant Vogtle Units 3 and 4 with in service dates of November 2021 and November 2022, respectively, is as follows:

| | | *(in billions)* |
|---|---|---|
| Project capital cost forecast | $ | 7.3 |
| Net investment as of December 31, 2017 | | (3.4) |
| **Remaining estimate to complete** | **$** | **3.9** |

Note: Excludes financing costs capitalized through AFUDC and is net of payments received under the Guarantee Settlement Agreement and the Customer Refunds.

Georgia Power estimates that its financing costs for construction of Plant Vogtle Units 3 and 4 will total approximately $3.1 billion , of which $1.6 billion had been incurred through December 31, 2017 .

As construction continues, challenges with management of contractors, subcontractors, and vendors, labor productivity and availability, fabrication, delivery, assembly, and installation of plant systems, structures, and components (some of which are based on new technology and have not yet operated in the global nuclear industry at this scale), or other issues could arise and change the projected schedule and estimated cost.

There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4 at the federal and state level and additional challenges may arise. Processes are in place that are designed to assure compliance with the requirements specified in the Westinghouse Design Control Document and the combined construction and operating licenses, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance matters, including the timely resolution of Inspections, Tests, Analyses, and Acceptance Criteria and the related approvals by the NRC, may arise, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs.

The ultimate outcome of these matters cannot be determined at this time.

### *Other Matters*

As of December 31, 2017, Georgia Power had borrowed $2.6 billion related to Plant Vogtle Units 3 and 4 costs through the Loan Guarantee Agreement and a multi-advance credit facility among Georgia Power, the DOE, and the FFB, which provides for borrowings of up to $3.46 billion , subject to the satisfaction of certain conditions. On September 28, 2017, the DOE issued a conditional commitment to Georgia Power for up to approximately $1.67 billion in additional guaranteed loans under the Loan Guarantee Agreement. This conditional commitment expires on June 30, 2018, subject to any further extension approved by the DOE. Final approval and issuance of these additional loan guarantees by the DOE cannot be assured and are subject to the negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions. See Note 6 under " DOE Loan Guarantee Borrowings " for additional information, including applicable covenants, events of default, mandatory prepayment events, and conditions to borrowing.

The ultimate outcome of these matters cannot be determined at this time.

## Other Matters

A wholly-owned subsidiary of Southern Company Gas owns and operates a natural gas storage facility consisting of two salt dome caverns in Louisiana. Periodic integrity tests are required in accordance with rules of the Louisiana Department of Natural

Resources (DNR). In August 2017, in connection with an ongoing integrity project, updated seismic mapping indicated the proximity of one of the caverns to the edge of the salt dome may be less than the required minimum and could result in Southern Company Gas retiring the cavern early. At December 31, 2017, the facility's property, plant, and equipment had a net book value of $112 million , of which the cavern itself represents approximately 20% . A potential early retirement of this cavern is dependent upon several factors including compliance with an order from the Louisiana DNR detailing the requirements to place the cavern back in service, which includes, among other things, obtaining core samples to determine the composition of the sheath surrounding the edge of the salt dome.

The cavern continues to maintain its pressures and overall structural integrity. These events were considered in connection with Southern Company Gas' annual long-lived asset impairment analysis, which determined there was no impairment as of December 31, 2017. Any changes in results of monitoring activities, rates at which expiring capacity contracts are re-contracted, timing of placing the cavern back in service, or Louisiana DNR requirements could trigger impairment. Further, early retirement of the cavern could trigger impairment of other long-lived assets associated with the natural gas storage facility. The ultimate outcome of this matter cannot be determined at this time, but could have a significant impact on Southern Company's financial statements.

**4. JOINT OWNERSHIP AGREEMENTS**

Alabama Power owns an undivided interest in Units 1 and 2 at Plant Miller and related facilities jointly with PowerSouth Energy Cooperative, Inc. Georgia Power owns undivided interests in Plants Vogtle, Hatch, Wansley, and Scherer in varying amounts jointly with one or more of the following entities: Oglethorpe Power Corporation (OPC), MEAG Power, the City of Dalton, Georgia, acting by and through its Board of Water, Light, and Sinking Fund Commissioners, doing business as Dalton Utilities, Florida Power & Light Company, and Jacksonville Electric Authority. In addition, Georgia Power has joint ownership agreements with OPC for the Rocky Mountain facilities. In August 2016, Georgia Power sold its 33% ownership interest in the Intercession City combustion turbine unit to Duke Energy Florida, LLC. Southern Power owns an undivided interest in Plant Stanton Unit A and related facilities jointly with the Orlando Utilities Commission, Kissimmee Utility Authority, and Florida Municipal Power Agency. Southern Company Gas has a 50% undivided ownership interest in the Dalton Pipeline jointly with The Williams Companies, Inc.

At December 31, 2017 , Alabama Power's, Georgia Power's, Southern Power's, and Southern Company Gas' percentage ownership and investment (exclusive of nuclear fuel) in jointly-owned facilities in commercial operation with the above entities were as follows:

| Facility (Type) | Percent Ownership | Plant in Service | Accumulated Depreciation | CWIP |
|---|---|---|---|---|
| | | | *(in millions)* | |
| Plant Vogtle (nuclear) Units 1 and 2 | 45.7% | $ 3,564 | $ 2,141 | $ 70 |
| Plant Hatch (nuclear) | 50.1 | 1,321 | 595 | 87 |
| Plant Miller (coal) Units 1 and 2 | 91.8 | 1,717 | 619 | 54 |
| Plant Scherer (coal) Units 1 and 2 | 8.4 | 261 | 93 | 8 |
| Plant Wansley (coal) | 53.5 | 1,053 | 335 | 72 |
| Rocky Mountain (pumped storage) | 25.4 | 182 | 132 | — |
| Plant Stanton (combined cycle) Unit A | 65.0 | 155 | 55 | — |
| Dalton Pipeline (natural gas pipeline) | 50.0 | 241 | 2 | 13 |

Georgia Power also owns 45.7% of Plant Vogtle Units 3 and 4, which are currently under construction and had a CWIP balance of $3.3 billion as of December 31, 2017 . See Note 3 under " Nuclear Construction " for additional information.

Alabama Power and Georgia Power have contracted to operate and maintain their jointly-owned facilities, except for Rocky Mountain, as agents for their respective co-owners. Southern Power has a service agreement with SCS whereby SCS is responsible for the operation and maintenance of Plant Stanton Unit A. The companies' proportionate share of their plant operating expenses is included in the corresponding operating expenses in the statements of income and each company is responsible for providing its own financing.

Southern Company Gas entered into an agreement to lease its 50% undivided ownership in the Dalton Pipeline that became effective when it was placed in service on August 1, 2017. Under the lease, Southern Company Gas will receive approximately $26 million annually for an initial term of 25 years . The lessee is responsible for maintaining the pipeline during the lease term and for providing service to transportation customers under its FERC-regulated tariff.

## 5. INCOME TAXES

Southern Company files a consolidated federal income tax return and various state income tax returns, some of which are combined or unitary. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. PowerSecure and Southern Company Gas became participants in the income tax allocation agreement as of May 9, 2016 and July 1, 2016, respectively. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

### Federal Tax Reform Legislation

Following the enactment of the Tax Reform Legislation, the SEC staff issued Staff Accounting Bulletin 118 – "Income Tax Accounting Implications of the Tax Cuts and Jobs Act" (SAB 118), which provides for a measurement period of up to one year from the enactment date to complete accounting under GAAP for the tax effects of the legislation. Due to the complex and comprehensive nature of the enacted tax law changes, and their application under GAAP, Southern Company considers all amounts recorded in the financial statements as a result of the Tax Reform Legislation to be "provisional" as discussed in SAB 118 and subject to revision. Southern Company is awaiting additional guidance from industry and income tax authorities in order to finalize its accounting. The ultimate impact of the Tax Reform Legislation on deferred income tax assets and liabilities and the related regulatory assets and liabilities cannot be determined at this time. See Note 3 under "Regulatory Matters" for additional information.

### Current and Deferred Income Taxes

Details of income tax provisions are as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| Federal — | | | |
| Current | **$ (62)** | $ 1,184 | $ (177) |
| Deferred | **(6)** | (342) | 1,266 |
| | **(68)** | 842 | 1,089 |
| State — | | | |
| Current | **37** | (108) | (33) |
| Deferred | **173** | 217 | 138 |
| | **210** | 109 | 105 |
| Total | **$ 142** | $ 951 | $ 1,194 |

Net cash payments (refunds) for income taxes in 2017 , 2016 , and 2015 were $(410) million , $(148) million , and $(9) million , respectively.

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The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| Deferred tax liabilities — | | |
| Accelerated depreciation | **$ 10,267** | $ 15,392 |
| Property basis differences | **955** | 2,708 |
| Leveraged lease basis differences | **251** | 314 |
| Employee benefit obligations | **516** | 737 |
| Premium on reacquired debt | **54** | 89 |
| Regulatory assets associated with employee benefit obligations | **1,046** | 1,584 |
| Regulatory assets associated with AROs | **1,225** | 1,781 |
| Other | **697** | 907 |
| Total | **15,011** | 23,512 |
| Deferred tax assets — | | |
| Federal effect of state deferred taxes | **326** | 597 |
| Employee benefit obligations | **1,307** | 1,868 |
| Over recovered fuel clause | **—** | 66 |
| Other property basis differences | **446** | 401 |
| Deferred costs | **69** | 100 |
| ITC carryforward | **2,420** | 1,974 |
| Federal NOL carryforward | **518** | 1,084 |
| Unbilled revenue | **57** | 92 |
| Other comprehensive losses | **84** | 152 |
| AROs | **1,197** | 1,732 |
| Estimated Loss on Kemper IGCC | **722** | 484 |
| Deferred state tax assets | **328** | 266 |
| Regulatory liability associated with the Tax Reform Legislation (not subject to normalization) | **465** | — |
| Other | **485** | 679 |
| Total | **8,424** | 9,495 |
| Valuation allowance | **(149)** | (23) |
| Total deferred income taxes | **6,736** | 14,040 |
| Portion included in accumulated deferred tax assets | **(106)** | (52) |
| Accumulated deferred income taxes | **$ 6,842** | $ 14,092 |

The implementation of the Tax Reform Legislation significantly reduced accumulated deferred income taxes, partially offset by bonus depreciation provisions in the Protecting Americans from Tax Hikes Act. The Tax Reform Legislation also significantly reduced tax-related regulatory assets and increased tax-related regulatory liabilities.

At December 31, 2017 , the tax-related regulatory assets to be recovered from customers were $825 million . These assets are primarily attributable to tax benefits flowed through to customers in prior years, deferred taxes previously recognized at rates lower than the current enacted tax law, and taxes applicable to capitalized interest.

At December 31, 2017 , the tax-related regulatory liabilities to be credited to customers were $7.3 billion . These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized ITCs.

In accordance with regulatory requirements, deferred federal ITCs for the traditional electric operating companies and the natural gas distribution utilities are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $22 million in 2017 , $22 million in 2016 , and $21 million in 2015 . Southern Power's deferred federal ITCs are amortized to income tax expense over the life of the asset. Credits amortized in this manner amounted to $57 million in 2017 , $37 million in 2016 , and $19 million in 2015 . Also, Southern Power received cash related to federal ITCs under the renewable energy incentives of $162 million for the year ended December 31, 2015 . No cash was received related to these incentives in 2017 and 2016. Furthermore, the tax basis of the asset is reduced by 50% of the ITCs received, resulting in a net deferred tax asset. Southern Power has elected to recognize the tax benefit of this basis difference as a reduction to income tax expense in the year in which the plant reaches commercial operation. The tax benefit of the related basis differences reduced income tax expense by $18 million in 2017 , $173 million in 2016 , and $54 million in 2015 . See " Unrecognized Tax Benefits " below for further information.

***Tax Credit Carryforwards***

At December 31, 2017 , Southern Company had federal ITC and PTC carryforwards (primarily related to Southern Power) which are expected to result in $2.1 billion of federal income tax benefits. The federal ITC carryforwards begin expiring in 2034 but are expected to be fully utilized by 2027. The PTC carryforwards begin expiring in 2032 but are expected to be fully utilized by 2027. The acquisition of additional renewable projects could further delay existing tax credit carryforwards. The ultimate outcome of these matters cannot be determined at this time.

Additionally, Southern Company had state ITC carryforwards for the state of Georgia totaling approximately $318 million , which will expire between 2020 and 2027 but are expected to be fully utilized.

***Net Operating Loss***

After carrying back portions of the federal NOL generated in 2016, Southern Company had a consolidated federal NOL carryforward of approximately $2.3 billion at December 31, 2017 . The federal NOL will begin expiring in 2037 but is expected to be fully utilized by 2019. The ultimate outcome of this matter cannot be determined at this time.

At December 31, 2017 , the state NOL carryforwards for Southern Company's subsidiaries were as follows:

| Jurisdiction | Approximate NOL Carryforwards | Approximate Net State Income Tax Benefit | Tax Year NOL Begins Expiring |
|---|---|---|---|
| | *(in millions)* | | |
| Mississippi | $ 2,890 | $ 114 | 2032 |
| Oklahoma | 986 | 47 | 2036 |
| Georgia | 524 | 23 | 2019 |
| New York | 229 | 13 | 2036 |
| New York City | 209 | 15 | 2036 |
| Florida | 304 | 13 | 2034 |
| Other states | 465 | 24 | Various |
| Total | $ 5,607 | $ 249 | |

### Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| Federal statutory rate | **35.0 %** | 35.0 % | 35.0 % |
| State income tax, net of federal deduction | **12.5** | 2.1 | 1.9 |
| Employee stock plans dividend deduction | **(4.1)** | (1.2) | (1.2) |
| Non-deductible book depreciation | **3.1** | 0.9 | 1.2 |
| AFUDC-Equity | **(2.6)** | (2.0) | (2.2) |
| Non-deductible equity portion on Kemper IGCC write-off | **15.7** | — | — |
| ITC basis difference | **(1.7)** | (5.0) | (1.5) |
| Federal PTCs | **(12.1)** | (1.2) | — |
| Amortization of ITC | **(4.2)** | (0.9) | (0.5) |
| Tax Reform Legislation | **(25.6)** | — | — |
| Other | **(2.7)** | (0.4) | 0.2 |
| Effective income tax rate | **13.3 %** | 27.3 % | 32.9 % |

Southern Company's effective tax rate is typically lower than the statutory rate due to employee stock plans' dividend deduction, non-taxable AFUDC equity, and federal income tax benefits from ITCs and PTCs. However, in 2017, the effective tax rate was primarily lower due to the remeasurement of deferred income taxes resulting from the Tax Reform Legislation.

In March 2016, the FASB issued ASU 2016-09, which changed the accounting for income taxes for share-based payment award transactions. Entities are required to recognize all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation as income tax expense or benefit in the income statement. The adoption of ASU 2016-09 did not have a material impact on Southern Company's overall effective tax rate. See Note 1 under " Recently Issued Accounting Standards " for additional information.

### Legal Entity Reorganization

In September 2017, Southern Power began a legal entity reorganization of various direct and indirect subsidiaries that own and operate substantially all of its solar facilities, including certain subsidiaries owned in partnership with various third parties. The reorganization included the purchase of all of the redeemable noncontrolling interests, representing 10% of the membership interests, in Southern Turner Renewable Energy, LLC. The reorganization is expected to be substantially completed in the first quarter 2018 and is expected to result in estimated tax benefits totaling between $50 million and $55 million related to certain changes in state apportionment rates and net operating loss carryforward utilization that will be recorded in the first quarter 2018. The ultimate outcome of this matter cannot be determined at this time.

### Unrecognized Tax Benefits

Changes during the year in unrecognized tax benefits were as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| Unrecognized tax benefits at beginning of year | **$ 484** | $ 433 | $ 170 |
| Tax positions increase from current periods | **10** | 45 | 43 |
| Tax positions increase from prior periods | **10** | 21 | 240 |
| Tax positions decrease from prior periods | **(196)** | (15) | (20) |
| Reductions due to settlements | **(290)** | — | — |
| Balance at end of year | **$ 18** | $ 484 | $ 433 |

The tax positions increase from current and prior periods for 2017 and 2016 relate primarily to state tax benefits and charitable contribution carryforwards that were impacted as a result of the settlement of R&E expenditures associated with the Kemper County energy facility, as well as deductions for R&E expenditures associated with the Kemper County energy facility. The tax positions decrease from prior periods for 2017 and 2016 , and the reductions due to settlements for 2017 , relate primarily to the settlement of R&E expenditures associated with the Kemper County energy facility and federal income tax benefits from deferred ITCs. See Note 3 under " Kemper County Energy Facility " and " Section 174 Research and Experimental Deduction " herein for more information.

The impact on Southern Company's effective tax rate, if recognized, is as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | (in millions) | |
| Tax positions impacting the effective tax rate | **$ 18** | $ 20 | $ 10 |
| Tax positions not impacting the effective tax rate | **—** | 464 | 423 |
| Balance of unrecognized tax benefits | **$ 18** | $ 484 | $ 433 |

The tax positions impacting the effective tax rate primarily relate to state tax benefits and charitable contribution carryforwards that were impacted as a result of the settlement of R&E expenditures associated with the Kemper County energy facility and Southern Company's estimate of the uncertainty related to the amount of those benefits. The tax positions not impacting the effective tax rate for 2016 and 2015 relate to deductions for R&E expenditures associated with the Kemper County energy facility. See " Section 174 Research and Experimental Deduction " herein for more information. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

Accrued interest for all tax positions other than the Section 174 R&E deductions was immaterial for all years presented.

Southern Company classifies interest on tax uncertainties as interest expense. Southern Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months . The settlement of federal and state audits could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2016. Southern Company is a participant in the Compliance Assurance Process of the IRS. However, the pre-Merger Southern Company Gas 2014, 2015, and June 30, 2016 federal tax returns are currently under audit. The audits for Southern Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2011.

***Section 174 Research and Experimental Deduction***

Southern Company has reflected deductions for R&E expenditures related to the Kemper County energy facility in its federal income tax calculations since 2013 and filed amended federal income tax returns for 2008 through 2013 to also include such deductions. In December 2016, Southern Company and the IRS reached a proposed settlement, which was approved on September 8, 2017 by the U.S. Congress Joint Committee on Taxation, resolving a methodology for these deductions. As a result of this approval, Southern Company recognized $176 million of previously unrecognized tax benefits and reversed $36 million of associated accrued interest.

## 6. FINANCING

### Securities Due Within One Year

A summary of scheduled maturities of securities due within one year at December 31 was as follows:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Senior notes | **$ 2,354** | $ 1,995 |
| Other long-term debt | **1,420** | 485 |
| Revenue bonds (*) | **90** | 76 |
| Capitalized leases | **31** | 32 |
| Unamortized debt issuance expense/discount | **(3)** | (1) |
| Total | **$ 3,892** | $ 2,587 |

(*) Includes $50 million in revenue bonds classified as short term at December 31, 2017 that were remarketed in an index rate mode subsequent to December 31, 2017. Also includes $40 million in pollution control revenue bonds classified as short term since they are variable rate demand obligations supported by short-term credit facilities; however, the final maturity dates range from 2020 to 2028.

Maturities through 2022 applicable to total long-term debt are as follows: $3.9 billion in 2018 ; $3.2 billion in 2019 ; $3.2 billion in 2020 ; $3.1 billion in 2021 ; and $2.2 billion in 2022 .

### Bank Term Loans

Southern Company and certain of its subsidiaries have entered into various bank term loan agreements. Unless otherwise stated, the proceeds of these loans were used to repay existing indebtedness and for general corporate purposes, including working capital and, for the subsidiaries, their continuous construction programs.

At December 31, 2017 , Southern Company, Alabama Power, Georgia Power, Mississippi Power, and Southern Power Company had outstanding bank term loans totaling $450 million , $45 million , $250 million , $900 million , and $420 million , respectively, of which $1.5 billion are reflected in the statements of capitalization as long-term debt and $600 million are reflected in the balance sheet as notes payable. At December 31, 2016 , Southern Company, Alabama Power, Gulf Power, Mississippi Power, and Southern Power Company had outstanding bank term loans totaling $400 million , $45 million , $100 million , $1.2 billion , and $380 million , respectively, of which $2.0 billion were reflected in the statements of capitalization as long-term debt and $100 million were reflected in the balance sheet as notes payable.

In June 2017, Southern Company entered into two $100 million aggregate principal amount short-term floating rate bank term loan agreements, which mature on June 21, 2018 and June 29, 2018 and bear interest based on one -month LIBOR.

In August 2017, Southern Company borrowed $250 million pursuant to a short-term uncommitted bank credit arrangement, which bears interest at a rate agreed upon by Southern Company and the bank from time to time and is payable on no less than 30 days' demand by the bank.

In June 2017, Georgia Power entered into two short-term floating rate bank loans in aggregate principal amounts of $50 million and $150 million , with maturity dates of December 1, 2017 and May 31, 2018, respectively, and one long-term floating rate bank loan of $100 million , with a maturity date of June 28, 2018, which was amended in August 2017 to extend the maturity date to October 26, 2018. These loans bear interest based on one-month LIBOR. Also in June 2017, Georgia Power borrowed $500 million pursuant to a short-term uncommitted bank credit arrangement, which bears interest at a rate agreed upon by Georgia Power and the bank from time to time and is payable on no less than 30 days ' demand by the bank.

In August 2017, Georgia Power repaid its $50 million floating rate bank loan due December 1, 2017 and $250 million of the $500 million aggregate principal amount outstanding pursuant to its uncommitted bank credit arrangement. In December 2017, Georgia Power repaid the remaining $250 million aggregate principal amount outstanding pursuant to its uncommitted bank credit arrangement.

In March 2017, Gulf Power extended the maturity of its $100 million short-term floating rate bank loan bearing interest based on one -month LIBOR from April 2017 to October 2017 and subsequently repaid the loan in May 2017.

In June 2017, Mississippi Power prepaid $300 million of the outstanding principal amount under its $1.2 billion unsecured term loan, which matures on March 30, 2018.

In September 2017, Southern Power amended its $60 million aggregate principal amount floating rate term loan to, among other things, increase the aggregate principal amount to $100 million and extend the maturity date from September 2017 to October 2018.

The outstanding bank loans as of December 31, 2017 have covenants that limit debt levels to a percentage of total capitalization. The percentage is 70% for Southern Company and 65% for Alabama Power, Georgia Power, Mississippi Power, and Southern Power Company, as defined in the agreements. For purposes of these definitions, debt excludes any long-term debt payable to affiliated trusts and other hybrid securities. Additionally, for Southern Company and Southern Power Company, for purposes of these definitions, debt excludes any project debt incurred by certain subsidiaries of Southern Power Company to the extent such debt is non-recourse to Southern Power Company and capitalization excludes the capital stock or other equity attributable to such subsidiary. At December 31, 2017 , each of Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power Company was in compliance with its debt limits.

### DOE Loan Guarantee Borrowings

Pursuant to the loan guarantee program established under Title XVII of the Energy Policy Act of 2005 (Title XVII Loan Guarantee Program), Georgia Power and the DOE entered into the Loan Guarantee Agreement in 2014, under which the DOE agreed to guarantee the obligations of Georgia Power under a note purchase agreement (FFB Note Purchase Agreement) among the DOE, Georgia Power, and the FFB and a related promissory note (FFB Promissory Note). The FFB Note Purchase Agreement and the FFB Promissory Note provide for a multi-advance term loan facility (FFB Credit Facility), under which Georgia Power may make term loan borrowings through the FFB.

On July 27, 2017, Georgia Power entered into an amendment to the Loan Guarantee Agreement (LGA Amendment) in connection with the DOE's consent to Georgia Power's entry into the Vogtle Services Agreement and the related intellectual property licenses (IP Licenses).

Under the terms of the Loan Guarantee Agreement, upon termination of the Vogtle 3 and 4 Agreement, further advances are conditioned upon the DOE's approval of any agreements entered into in replacement of the Vogtle 3 and 4 Agreement. Under the terms of the LGA Amendment, Georgia Power will not request any advances unless and until certain conditions are satisfied, including (i) receipt of the DOE's approval of the Bechtel Agreement (together with the Vogtle Services Agreement and the IP Licenses, the Replacement EPC Arrangements) and (ii) Georgia Power's entry into a further amendment to the Loan Guarantee Agreement with the DOE to reflect the Replacement EPC Arrangements.

Proceeds of advances made under the FFB Credit Facility are used to reimburse Georgia Power for Eligible Project Costs. Aggregate borrowings under the FFB Credit Facility may not exceed the lesser of (i) 70% of Eligible Project Costs or (ii) approximately $3.46 billion .

On September 28, 2017, the DOE issued a conditional commitment to Georgia Power for up to approximately $1.67 billion of additional guaranteed loans under the Loan Guarantee Agreement. This conditional commitment expires on June 30, 2018, subject to any further extension approved by the DOE. Final approval and issuance of these additional loan guarantees by the DOE cannot be assured and are subject to the negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions.

All borrowings under the FFB Credit Facility are full recourse to Georgia Power, and Georgia Power is obligated to reimburse the DOE for any payments the DOE is required to make to the FFB under the guarantee. Georgia Power's reimbursement obligations to the DOE are full recourse and secured by a first priority lien on (i) Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) Georgia Power's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. There are no restrictions on Georgia Power's ability to grant liens on other property.

In addition to the conditions described above, future advances are subject to satisfaction of customary conditions, as well as certification of compliance with the requirements of the Title XVII Loan Guarantee Program, including accuracy of project-related representations and warranties, delivery of updated project-related information, and evidence of compliance with the prevailing wage requirements of the Davis-Bacon Act of 1931, as amended, and certification from the DOE's consulting engineer that proceeds of the advances are used to reimburse Eligible Project Costs.

Upon satisfaction of all conditions described above, advances may be requested under the FFB Credit Facility on a quarterly basis through 2020. The final maturity date for each advance under the FFB Credit Facility is February 20, 2044. Interest is payable quarterly and principal payments will begin on February 20, 2020. Borrowings under the FFB Credit Facility will bear interest at the applicable U.S. Treasury rate plus a spread equal to 0.375% .

At both December 31, 2017 and 2016 , Georgia Power had $2.6 billion of borrowings outstanding under the FFB Credit Facility.

Under the Loan Guarantee Agreement, Georgia Power is subject to customary borrower affirmative and negative covenants and events of default. In addition, Georgia Power is subject to project-related reporting requirements and other project-specific covenants and events of default.

In the event certain mandatory prepayment events occur, the FFB's commitment to make further advances under the FFB Credit Facility will terminate and Georgia Power will be required to prepay the outstanding principal amount of all borrowings under the FFB Credit Facility over a period of five years (with level principal amortization). Among other things, these mandatory prepayment events include (i) the termination of the Vogtle Services Agreement or rejection of the Vogtle Services Agreement in bankruptcy if Georgia Power does not maintain access to intellectual property rights under the IP Licenses; (ii) a decision by Georgia Power not to continue construction of Plant Vogtle Units 3 and 4; (iii) cancellation of Plant Vogtle Units 3 and 4 by the Georgia PSC, or by Georgia Power if authorized by the Georgia PSC; and (iv) cost disallowances by the Georgia PSC that could have a material adverse effect on completion of Plant Vogtle Units 3 and 4 or Georgia Power's ability to repay the outstanding borrowings under the FFB Credit Facility. Under certain circumstances, insurance proceeds and any proceeds from an event of taking must be applied to immediately prepay outstanding borrowings under the FFB Credit Facility. In addition, if Georgia Power discontinues construction of Plant Vogtle Units 3 and 4, Georgia Power would be obligated to immediately repay a portion of the outstanding borrowings under the FFB Credit Facility to the extent such outstanding borrowings exceed 70% of Eligible Project Costs, net of the proceeds received by Georgia Power under the Guarantee Settlement Agreement. Georgia Power also may voluntarily prepay outstanding borrowings under the FFB Credit Facility. Under the FFB Credit Facility, any prepayment (whether mandatory or optional) will be made with a make-whole premium or discount, as applicable.

In connection with any cancellation of Plant Vogtle Units 3 and 4 that results in a mandatory prepayment event, the DOE may elect to continue construction of Plant Vogtle Units 3 and 4. In such an event, the DOE will have the right to assume Georgia Power's rights and obligations under the principal agreements relating to Plant Vogtle Units 3 and 4 and to acquire all or a portion of Georgia Power's ownership interest in Plant Vogtle Units 3 and 4.

**Senior Notes**

Southern Company and its subsidiaries issued a total of $4.0 billion of senior notes in 2017 . Southern Company issued $0.3 billion and its subsidiaries issued a total of $3.7 billion . The proceeds of Southern Company's issuances were used to repay short-term indebtedness and for other general corporate purposes. Except as described below, the proceeds of Southern Company's subsidiaries' issuances were used to repay long-term indebtedness, to repay short-term indebtedness, and for other general corporate purposes, including the applicable subsidiaries' continuous construction programs. A portion of the proceeds of Gulf Power's senior note issuances was used to redeem all of Gulf Power's outstanding shares of preference stock. See " Redeemable Preferred Stock of Subsidiaries " herein for additional information.

At December 31, 2017 and 2016 , Southern Company and its subsidiaries had a total of $35.1 billion and $33.0 billion , respectively, of senior notes outstanding. At December 31, 2017 and 2016 , Southern Company had a total of $10.2 billion and $10.3 billion , respectively, of senior notes outstanding. These amounts include senior notes due within one year.

Since Southern Company is a holding company, the right of Southern Company and, hence, the right of creditors of Southern Company (including holders of Southern Company senior notes) to participate in any distribution of the assets of any subsidiary of Southern Company, whether upon liquidation, reorganization or otherwise, is subject to prior claims of creditors and preferred stockholders of such subsidiary.

**Junior Subordinated Notes**

At December 31, 2017 and 2016 , Southern Company and its subsidiaries had a total of $3.6 billion and $2.4 billion , respectively, of junior subordinated notes outstanding.

In June 2017, Southern Company issued $500 million aggregate principal amount of Series 2017A 5.325% Junior Subordinated Notes due June 21, 2057. The proceeds were used to repay short-term indebtedness and for other general corporate purposes.

In November 2017, Southern Company issued $450 million aggregate principal amount of Series 2017B 5.25% Junior Subordinated Notes due December 1, 2077. The proceeds were used to repay short-term indebtedness and for other general corporate purposes.

In September 2017, Georgia Power issued $270 million aggregate principal amount of Series 2017A 5.00% Junior Subordinated Notes due October 1, 2077. The proceeds were used to redeem all outstanding shares of Georgia Power's preferred and preference stock. See " Redeemable Preferred Stock of Subsidiaries " herein for additional information.

**Pollution Control Revenue Bonds**

Pollution control revenue bond obligations represent loans to the traditional electric operating companies from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. In some cases, the pollution control revenue bond obligations represent obligations under installment sales agreements with respect to facilities constructed with the proceeds of revenue bonds issued by public authorities. The traditional electric operating companies had $3.3 billion of outstanding pollution control revenue bond obligations at December 31, 2017 and 2016 , which includes pollution control revenue bonds classified as due within one year. The traditional electric operating companies are required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

**Plant Daniel Revenue Bonds**

In 2011, in connection with Mississippi Power's election under its operating lease of Plant Daniel Units 3 and 4 to purchase the assets, Mississippi Power assumed the obligations of the lessor related to $270 million aggregate principal amount of Mississippi Business Finance Corporation Taxable Revenue Bonds, 7.13% Series 1999A due October 20, 2021, issued for the benefit of the lessor. See " Assets Subject to Lien " herein for additional information.

**Gas Facility Revenue Bonds**

Pivotal Utility Holdings, Inc., a subsidiary of Southern Company Gas (Pivotal Utility Holdings), is party to a series of loan agreements with the New Jersey Economic Development Authority and Brevard County, Florida under which five series of gas facility revenue bonds have been issued with maturities ranging from 2022 to 2033. These revenue bonds are issued by state agencies or counties to investors, and proceeds from each issuance then are loaned to Southern Company Gas. The amount of gas facility revenue bonds outstanding at December 31, 2017 and 2016 was $200 million .

The Elizabethtown Gas asset sale agreement requires that bonds representing $180 million of the total that are currently eligible for redemption at par be redeemed on or prior to consummation of the sale. The ultimate outcome of this matter cannot be determined at this time. See Note 12 under "Southern Company Gas – Proposed Sale of Elizabethtown Gas and Elkton Gas" for additional information.

**Other Revenue Bonds**

Other revenue bond obligations represent loans to Mississippi Power from a public authority of funds derived from the sale by such authority of revenue bonds issued to finance a portion of the costs of constructing the Kemper County energy facility and related facilities.

Mississippi Power had $50 million of such obligations outstanding related to tax-exempt revenue bonds at December 31, 2017 and 2016 . Such amounts are reflected in the statements of capitalization as other long-term debt.

**First Mortgage Bonds**

Nicor Gas, a subsidiary of Southern Company Gas, had $1.0 billion and $625 million of first mortgage bonds outstanding at December 31, 2017 and 2016 , respectively. These bonds have been issued with maturities ranging from 2019 to 2057. Substantially all of Nicor Gas' properties are subject to the lien of the indenture securing these first mortgage bonds. See " Assets Subject to Lien " herein for additional information.

On August 10, 2017, Nicor Gas issued $100 million aggregate principal amount of First Mortgage Bonds 3.03% Series due August 10, 2027 and $100 million aggregate principal amount of First Mortgage Bonds 3.62% Series due August 10, 2037. On November 1, 2017, Nicor Gas issued $100 million aggregate principal amount of First Mortgage Bonds 3.85% Series due August 10, 2047 and $100 million aggregate principal amount of First Mortgage Bonds 4.00% Series due August 10, 2057. The proceeds were used to repay short-term indebtedness incurred under the Nicor Gas commercial paper program and for other working capital needs.

**Long-Term Debt Payable to an Affiliated Trust**

Alabama Power has formed a wholly-owned trust subsidiary for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to Alabama Power through the issuance of junior subordinated notes totaling $206 million outstanding as of December 31, 2017 and 2016 , which constitute substantially all of the assets of this trust and are reflected in the balance sheets as long-term debt payable. Alabama Power considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the trust's payment obligations with respect to these securities. At December 31, 2017 and 2016 , trust preferred securities of $200 million were outstanding.

**Capital Leases**

Assets acquired under capital leases are recorded in the balance sheets as property, plant, and equipment and the related obligations are classified as long-term debt.

In 2013, Mississippi Power entered into a nitrogen supply agreement for the air separation unit of the Kemper County energy facility, which resulted in a capital lease obligation of $74 million at December 31, 2016 . Following the suspension of the Kemper IGCC, Mississippi Power entered into an asset purchase and settlement agreement in December 2017 with the lessor, which terminated the capital lease obligation. See Note 3 under " Kemper County Energy Facility " for additional information.

At December 31, 2017 and 2016 , the capitalized lease obligations for Georgia Power's corporate headquarters building were $22 million and $28 million , respectively, with an annual interest rate of 7.9% .

At December 31, 2017 and 2016 , a subsidiary of Southern Company had capital lease obligations of approximately $177 million and $29 million , respectively, for an office building and certain computer equipment including desktops, laptops, servers, printers, and storage devices with annual interest rates that range from 1.5% to 4.7% .

**Assets Subject to Lien**

Each of Southern Company's subsidiaries is organized as a legal entity, separate and apart from Southern Company and its other subsidiaries. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its other subsidiaries.

**NOTES (continued)**
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Gulf Power has granted one or more liens on certain of its property in connection with the issuance of certain series of pollution control revenue bonds with an aggregate outstanding principal amount of $41 million as of December 31, 2017 .

The revenue bonds assumed in conjunction with Mississippi Power's purchase of Plant Daniel Units 3 and 4 are secured by Plant Daniel Units 3 and 4 and certain related personal property. See " Plant Daniel Revenue Bonds " herein for additional information.

On October 4, 2017, Mississippi Power executed agreements with its largest retail customer, Chevron Products Company (Chevron), to continue providing retail service to the Chevron refinery in Pascagoula, Mississippi through 2038, subject to the approval of the Mississippi PSC. The agreements grant Chevron a security interest in the co-generation assets, with a net book value of approximately $93 million , located at Chevron's refinery that is exercisable upon the occurrence of (i) certain bankruptcy events or (ii) other events of default coupled with specific reductions in steam output at the facility and a downgrade of Mississippi Power's credit rating to below investment grade by two of the three rating agencies.

See " DOE Loan Guarantee Borrowings " above for information regarding certain borrowings of Georgia Power that are secured by a first priority lien on (i) Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) Georgia Power's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4.

The first mortgage bonds issued by Nicor Gas are secured by substantially all of Nicor Gas' properties. See " First Mortgage Bonds " herein for additional information.

Under the terms of the PPA and the expansion PPA for Southern Power's Mankato project, which was acquired in 2016, approximately $442 million of assets, primarily related to property, plant, and equipment, are subject to lien at December 31, 2017 . See Note 12 under "Southern Power" for additional information.

During 2015, Southern Power indirectly acquired a 51% membership interest in RE Roserock LLC (Roserock), the owner of the Roserock solar facility in Pecos County, Texas. Roserock is in a litigation dispute with McCarthy Building Companies, Inc. (McCarthy) regarding damage to certain solar panels during installation. In connection therewith, Roserock is withholding payments of approximately $26 million from McCarthy, and McCarthy has filed mechanic's liens on the Roserock facility for the same amount. Southern Power intends to vigorously pursue its claims against McCarthy and defend against McCarthy's claims, the ultimate outcome of which cannot be determined at this time.

**Bank Credit Arrangements**

At December 31, 2017 , committed credit arrangements with banks were as follows:

| | Expires | | | | | | Executable Term Loans | | Expires Within One Year | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Company** | **2018** | **2019** | **2020** | **2022** | **Total** | **Unused** | **One Year** | **Two Years** | **Term Out** | **No Term Out** |
| | | | | | | *(in millions)* | | | | |
| Southern Company [(a)] | $ — | $ — | $ — | $ 2,000 | $ 2,000 | $ 1,999 | $ — | $ — | $ — | $ — |
| Alabama Power | 35 | — | 500 | 800 | 1,335 | 1,335 | — | — | — | 35 |
| Georgia Power | — | — | — | 1,750 | 1,750 | 1,732 | — | — | — | — |
| Gulf Power | 30 | 25 | 225 | — | 280 | 280 | 45 | — | 20 | 10 |
| Mississippi Power | 100 | — | — | — | 100 | 100 | — | — | — | 100 |
| Southern Power Company [(b)] | — | — | — | 750 | 750 | 728 | — | — | — | — |
| Southern Company Gas [(c)] | — | — | — | 1,900 | 1,900 | 1,890 | — | — | — | — |
| Other | 30 | — | — | — | 30 | 30 | 20 | — | 20 | 10 |
| Southern Company Consolidated | $ 195 | $ 25 | $ 725 | $ 7,200 | $ 8,145 | $ 8,094 | $ 65 | $ — | $ 40 | $ 155 |

(a) Represents the Southern Company parent entity.

(b) Does not include Southern Power's $120 million continuing letter of credit facility for standby letters of credit expiring in 2019, of which $19 million remains unused at December 31, 2017 .

(c) Southern Company Gas, as the parent entity, guarantees the obligations of Southern Company Gas Capital, which is the borrower of $1.4 billion of these arrangements. Southern Company Gas' committed credit arrangements also include $500 million for which Nicor Gas is the borrower and which is restricted for working capital needs of Nicor Gas.

In May 2017, Southern Company, Alabama Power, Georgia Power, and Southern Power Company each amended certain of their multi-year credit arrangements, which, among other things, extended the maturity dates from 2020 to 2022. Southern Company and Southern Power Company increased their borrowing ability under these arrangements to $2.0 billion from $1.25 billion and to $750 million from $600 million , respectively. Southern Company also terminated its $1.0 billion facility maturing in 2018. Also in May 2017, Southern Company Gas Capital and Nicor Gas terminated their existing credit arrangements for $1.3 billion and $700 million , respectively, which were to mature in 2017 and 2018, and entered into a new multi-year credit arrangement with $1.4 billion and $500 million currently allocated to Southern Company Gas Capital and Nicor Gas, respectively, maturing in 2022. Pursuant to the new multi-year credit arrangement, the allocations between Southern Company Gas Capital and Nicor Gas may be adjusted. In September 2017, Alabama Power also amended its $500 million multi-year credit arrangement, which, among other things, extended the maturity date from 2018 to 2020. In November 2017, Gulf Power amended $195 million of its multi-year credit arrangements to extend the maturity dates from 2017 and 2018 to 2020 and Mississippi Power amended its one-year credit arrangements in an aggregate amount of $100 million to extend the maturity dates from 2017 to 2018.

Most of the bank credit arrangements require payment of commitment fees based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees average less than $^1/_4$ of 1% for Southern Company, the traditional electric operating companies, Southern Power Company, Southern Company Gas, and Nicor Gas. Compensating balances are not legally restricted from withdrawal.

Subject to applicable market conditions, Southern Company and its subsidiaries expect to renew or replace their bank credit arrangements as needed, prior to expiration. In connection therewith, Southern Company and its subsidiaries may extend the maturity dates and/or increase or decrease the lending commitments thereunder.

Southern Company's, Southern Company Gas', and Nicor Gas' credit arrangements contain covenants that limit debt levels to 70% of total capitalization, as defined in the agreements, and most of the other subsidiaries' bank credit arrangements contain covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes the long-term debt payable to affiliated trusts and, in certain arrangements and other hybrid securities. Additionally, for Southern Company and Southern Power Company, for purposes of these definitions, debt excludes any project debt incurred by certain subsidiaries of Southern Power Company to the extent such debt is non-recourse to Southern Power Company and capitalization excludes the capital stock or other equity attributable to such subsidiaries. At December 31, 2017 , Southern Company, the traditional electric operating companies, Southern Power Company, Southern Company Gas, and Nicor Gas were each in compliance with their respective debt limit covenants.

A portion of the $8.1 billion unused credit with banks is allocated to provide liquidity support to the revenue bonds of the traditional electric operating companies and the commercial paper programs of Southern Company, the traditional electric operating companies, Southern Power Company, Southern Company Gas, and Nicor Gas. The amount of variable rate revenue bonds of the traditional electric operating companies outstanding requiring liquidity support as of December 31, 2017 was approximately $1.5 billion as compared to $1.9 billion at December 31, 2016 . In addition, at December 31, 2017 , the traditional electric operating companies had approximately $714 million of revenue bonds outstanding that were required to be remarketed within the next 12 months . Subsequent to December 31, 2017, $50 million of these revenue bonds of Mississippi Power which were in a long-term interest rate mode were remarketed in an index rate mode.

Southern Company, the traditional electric operating companies (other than Mississippi Power), Southern Power Company, Southern Company Gas, and Nicor Gas make short-term borrowings primarily through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above. Commercial paper and short-term bank term loans are included in notes payable in the balance sheets.

Details of short-term borrowings were as follows:

| | Short-term Debt at the End of the Period | | |
|---|---|---|---|
| | | Amount Outstanding | Weighted Average Interest Rate |
| | | *(in millions)* | |
| **December 31, 2017:** | | | |
| Commercial paper | **$** | **1,832** | **1.8%** |
| Short-term bank debt | | **607** | **2.3%** |
| Total | **$** | **2,439** | **1.9%** |
| **December 31, 2016:** | | | |
| Commercial paper | $ | 1,909 | 1.1% |
| Short-term bank debt | | 123 | 1.7% |
| Total | $ | 2,032 | 1.1% |

In addition to the short-term borrowings of Southern Power Company included in the table above, at December 31, 2016 , Southern Power Company subsidiaries had credit agreements (Project Credit Facilities) assumed with the acquisition of certain solar facilities, which were non-recourse to Southern Power Company, the proceeds of which were used to finance project costs related to such solar facilities. The Project Credit Facilities were fully repaid in January 2017 and had total amounts outstanding of $209 million at a weighted average interest rate of 2.1% at December 31, 2016 .

**Redeemable Preferred Stock of Subsidiaries**

At December 31, 2016 , each of the traditional electric operating companies had outstanding preferred and/or preference stock. During 2017, Alabama Power and Gulf Power each redeemed all of its outstanding preference stock and Georgia Power redeemed all of its outstanding preferred and preference stock. The preferred stock of Alabama Power and Mississippi Power contains a feature that allows the holders to elect a majority of such subsidiary's board of directors if preferred dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of Alabama Power and Mississippi Power, this preferred stock is presented as "Redeemable Preferred Stock of Subsidiaries" in a manner consistent with temporary equity under applicable accounting standards. The preferred and preference stock at Georgia Power and the preference stock at Alabama Power and Gulf Power did not contain such a provision. As a result, under applicable accounting standards, the preferred and preference stock at Georgia Power and the preference stock at Alabama Power and Gulf Power are presented as "Preferred and Preference Stock of Subsidiaries," a separate component of "Stockholders' Equity," on Southern Company's balance sheets, statements of capitalization, and statements of stockholders' equity.

The following table presents changes during the year in redeemable preferred stock of subsidiaries for Southern Company:

| | | Redeemable Preferred Stock of Subsidiaries |
|---|---|---|
| | | *(in millions)* |
| **Balance at December 31, 2014** | $ | 375 |
| Issued | | — |
| Redeemed | | (262) |
| Issuance costs | | 5 |
| **Balance at December 31, 2015:** | | 118 |
| Issued | | — |
| Redeemed | | — |
| **Balance at December 31, 2016:** | | 118 |
| Issued | | 250 |
| Redeemed | | (38) |
| Issuance costs | | (6) |
| **Balance at December 31, 2017:** | **$** | **324** |

## 7. COMMITMENTS

### Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of the generating plants, the Southern Company system has entered into various long-term commitments for the procurement and delivery of fossil and nuclear fuel which are not recognized on the balance sheets. In 2017 , 2016 , and 2015 , the traditional electric operating companies and Southern Power incurred fuel expense of $4.4 billion , $4.4 billion , and $4.8 billion , respectively, the majority of which was purchased under long-term commitments. Southern Company expects that a substantial amount of the Southern Company system's future fuel needs will continue to be purchased under long-term commitments.

In addition, the Southern Company system has entered into various long-term commitments for the purchase of capacity and electricity, some of which are accounted for as operating leases or have been used by a third party to secure financing. Total capacity expense under PPAs accounted for as operating leases was $235 million , $232 million , and $227 million for 2017 , 2016 , and 2015 , respectively.

Estimated total obligations under these commitments at December 31, 2017 were as follows:

| | Operating Leases | Other |
|---|---|---|
| | *(in millions)* | |
| 2018 | $ 247 | $ 7 |
| 2019 | 250 | 6 |
| 2020 | 247 | 4 |
| 2021 | 249 | 5 |
| 2022 | 252 | 4 |
| 2023 and thereafter | 806 | 38 |
| Total | $ 2,051 | $ 64 |

### Pipeline Charges, Storage Capacity, and Gas Supply

Pipeline charges, storage capacity, and gas supply include charges recoverable through a natural gas cost recovery mechanism, or alternatively, billed to marketers selling retail natural gas, as well as demand charges associated with Southern Company Gas' wholesale gas services. The gas supply balance includes amounts for gas commodity purchase commitments associated with Southern Company Gas' gas marketing services of 35 million mmBtu at floating gas prices calculated using forward natural gas prices at December 31, 2017 and valued at $101 million . Southern Company Gas provides guarantees to certain gas suppliers for certain of its subsidiaries in support of payment obligations.

Expected future contractual obligations for pipeline charges, storage capacity, and gas supply that are not recognized on the balance sheets as of December 31, 2017 were as follows:

| | Pipeline Charges, Storage Capacity, and Gas Supply |
|---|---|
| | *(in millions)* |
| 2018 | $ 813 |
| 2019 | 552 |
| 2020 | 416 |
| 2021 | 375 |
| 2022 | 339 |
| 2023 and thereafter | 2,294 |
| Total | $ 4,789 |

### Operating Leases

The Southern Company system has operating lease agreements with various terms and expiration dates. Total rent expense was $176 million , $169 million , and $130 million for 2017 , 2016 , and 2015 , respectively. Southern Company includes any step rents, fixed escalations, and lease concessions in its computation of minimum lease payments.

As of December 31, 2017 , estimated minimum lease payments under operating leases were as follows:

| | Minimum Lease Payments | | |
|---|---|---|---|
| | Barges & Railcars | Other (*) | Total |
| | | *(in millions)* | |
| 2018 | $ 21 | $ 128 | $ 149 |
| 2019 | 11 | 113 | 124 |
| 2020 | 9 | 99 | 108 |
| 2021 | 8 | 87 | 95 |
| 2022 | 6 | 77 | 83 |
| 2023 and thereafter | 5 | 963 | 968 |
| Total | $ 60 | $ 1,467 | $ 1,527 |

(*) Includes operating leases for cellular tower space, facilities, vehicles, and other equipment.

For the traditional electric operating companies, a majority of the barge and railcar lease expenses are recoverable through fuel cost recovery provisions.

In addition to the above rental commitments, Alabama Power and Georgia Power have obligations upon expiration of certain railcar leases with respect to the residual value of the leased property. These leases have terms expiring through 2024 with maximum obligations under these leases of $44 million . At the termination of the leases, the lessee may renew the lease, exercise its purchase option, or the property can be sold to a third party. Alabama Power and Georgia Power expect that the fair market value of the leased property would substantially reduce or eliminate the payments under the residual value obligations.

### Guarantees

In 2013, Georgia Power entered into an agreement that requires Georgia Power to guarantee certain payments of a gas supplier for Plant McIntosh for a period up to 15 years . The guarantee is expected to be terminated if certain events occur within one year of the initial gas deliveries in 2018 . In the event the gas supplier defaults on payments, the maximum potential exposure under the guarantee is approximately $43 million .

As discussed above under "Operating Leases," Alabama Power and Georgia Power have entered into certain residual value guarantees.

## 8. COMMON STOCK

### Stock Issued

During 2017 , Southern Company issued approximately 14.6 million shares of common stock primarily through employee equity compensation plans and received proceeds of approximately $659 million .

In addition, during the second and third quarters of 2017 , Southern Company issued a total of approximately 2.7 million shares of common stock through at-the-market issuances pursuant to sales agency agreements related to Southern Company's continuous equity offering program and received cash proceeds of approximately $134 million , net of $1.1 million in fees and commissions.

### Shares Reserved

At December 31, 2017 , a total of 71 million shares were reserved for issuance pursuant to the Southern Investment Plan, employee savings plans, the Outside Directors Stock Plan, the Omnibus Incentive Compensation Plan (which includes stock options and performance share units as discussed below), and an at-the-market program. Of the total 71 million shares reserved, there were 13 million shares of common stock remaining available for awards under the Omnibus Incentive Compensation Plan as of December 31, 2017 .

### Stock-Based Compensation

Stock-based compensation primarily in the form of performance share units and restricted stock units may be granted through the Omnibus Incentive Compensation Plan to a large segment of Southern Company system employees ranging from line management to executives. In 2015 and 2016, stock-based compensation consisted exclusively of performance share units. Beginning in 2017, stock-based compensation granted to employees includes restricted stock units in addition to performance share units. Prior to 2015, stock-based compensation also included stock options. As of December 31, 2017 , there were 5,112 current and former employees participating in the stock option, performance share unit, and restricted stock unit programs.

In conjunction with the Merger, stock-based compensation in the form of Southern Company restricted stock and performance share units was also granted to certain executives of Southern Company Gas through the Southern Company Omnibus Incentive Compensation Plan.

***Performance Share Units***

Performance share units granted to employees vest at the end of a three -year performance period. All unvested performance share units vest immediately upon a change in control where Southern Company is not the surviving corporation. Shares of Southern Company common stock are delivered to employees at the end of the performance period with the number of shares issued ranging from 0% to 200% of the target number of performance share units granted, based on achievement of the performance goals established by the Compensation Committee of the Southern Company Board of Directors.

Southern Company issues performance share units with performance goals based on three performance goals to employees. These include performance share units with performance goals based on the total shareholder return (TSR) for Southern Company common stock during the three -year performance period as compared to a group of industry peers, performance share units with performance goals based on Southern Company's cumulative earnings per share (EPS) over the performance period, and performance share units with performance goals based on Southern Company's equity-weighted ROE over the performance period.

In 2015 and 2016, the EPS-based and ROE-based awards each represented 25% of the total target grant date fair value of the performance share unit awards granted. The remaining 50% of the total target grant date fair value consisted of TSR-based awards. Beginning in 2017, the total target grant date fair value of the stock compensation awards granted was comprised 20% each of EPS-based awards and ROE-based awards and 30% each of TSR-based awards and restricted stock units.

The fair value of TSR-based performance share unit awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's common stock among the industry peers over the performance period. Southern Company recognizes compensation expense on a straight-line basis over the three -year performance period without remeasurement.

The fair values of the EPS-based awards and the ROE-based awards are based on the closing stock price of Southern Company common stock on the date of the grant. Compensation expense for the EPS-based and ROE-based awards is generally recognized ratably over the three -year performance period initially assuming a 100% payout at the end of the performance period. Employees become immediately vested in the TSR-based performance share units, along with the EPS-based and ROE-based awards, upon retirement. As a result, compensation expense for employees that are retirement eligible at the grant date is recognized immediately while compensation expense for employees that become retirement eligible during the vesting period is recognized over the period from grant date to the date of retirement eligibility. The expected payout related to the EPS-based and ROE-based awards is reevaluated annually with expense recognized to date increased or decreased based on the number of shares currently expected to be issued. Unlike the TSR-based awards, the compensation expense ultimately recognized for the EPS-based awards and the ROE-based awards will be based on the actual number of shares issued at the end of the performance period.

In determining the fair value of the TSR-based awards issued to employees, the expected volatility is based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate is based on the U.S. Treasury yield curve in effect at the time of grant that covers the performance period of the awards. The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of performance share award units granted:

| **Year Ended December 31** | **2017** | 2016 | 2015 |
|---|---|---|---|
| Expected volatility | **15.6%** | 15.0% | 12.9% |
| Expected term *(in years)* | **3** | 3 | 3 |
| Interest rate | **1.4%** | 0.8% | 1.0% |
| Weighted average grant-date fair value | **$49.08** | $45.06 | $46.38 |

The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2017 , 2016 , and 2015 was $49.21 , $48.87 , and $47.75 , respectively.

Total unvested performance share units outstanding as of December 31, 2016 were 3.2 million . During 2017 , 1.2 million performance share units were granted and 1.5 million performance share units were vested or forfeited, resulting in 2.9 million unvested performance share units outstanding at December 31, 2017 . The number of shares to be issued for the three -year performance and vesting period ended December 31, 2017 will be determined in the first quarter 2018 .

For the years ended December 31, 2017 , 2016 , and 2015 , total compensation cost for performance share units recognized in income was $74 million , $96 million , and $88 million , respectively, with the related tax benefit also recognized in income of $29 million , $37 million , and $34 million , respectively. As of December 31, 2017 , $30 million of total unrecognized compensation cost related to performance share award units will be recognized over a weighted-average period of approximately 21 months .

***Restricted Stock Units***

Beginning in 2017 , stock-based compensation granted to employees included restricted stock units in addition to performance share units. One-third of the restricted stock units granted to employees vest each year throughout a three -year service period. All unvested restricted stock units vest immediately upon a change in control where Southern Company is not the surviving corporation. Shares of Southern Company common stock are delivered to employees at the end of the vesting period.

The fair value of restricted stock units is based on the closing stock price of Southern Company common stock on the date of the grant. Since one-third of the restricted stock units vest each year throughout a three -year service period, compensation expense for restricted stock unit awards is generally recognized over the corresponding one -, two -, or three -year period. Employees become immediately vested in the restricted stock units upon retirement. As a result, compensation expense for employees that are retirement eligible at the grant date is recognized immediately while compensation expense for employees that become retirement eligible during the vesting period is recognized over the period from grant date to the date of retirement eligibility.

The weighted average grant-date fair value of restricted stock units granted during 2017 was $49.25 .

During 2017 , 0.6 million restricted stock units were granted and 0.1 million restricted stock units were vested or forfeited, resulting in 0.7 million unvested restricted stock units outstanding at December 31, 2017 , including previously issued restricted stock units related to other employee retention agreements.

For the year ended December 31, 2017 , total compensation cost for restricted stock units recognized in income was $25 million with the related tax benefit also recognized in income of $10 million . As of December 31, 2017 , $8 million of total unrecognized compensation cost related to restricted stock units will be recognized over a weighted-average period of approximately 13 months .

***Stock Options***

In 2015, Southern Company discontinued the granting of stock options and all outstanding options have vested. Stock options expire no later than 10 years after the grant date and the latest possible exercise will occur no later than November 2024.

Southern Company's activity in the stock option program for 2017 is summarized below:

| | Shares Subject to Option | Weighted Average Exercise Price |
|---|---|---|
| | *(in millions)* | |
| Outstanding at December 31, 2016 | 24.6 | $ 41.28 |
| Exercised | 6.0 | 40.03 |
| Cancelled | — | 39.90 |
| **Outstanding and Exercisable at December 31, 2017** | **18.6** | **$ 41.68** |

As of December 31, 2017 , the weighted average remaining contractual term for the options outstanding and options exercisable was approximately five years and the aggregate intrinsic value for the options outstanding and options exercisable was $119 million .

Total compensation cost for stock option awards and the related tax benefits recognized in income were immaterial for all years presented.

The total intrinsic value of options exercised during the years ended December 31, 2017 , 2016 , and 2015 was $64 million , $120 million , and $48 million , respectively. The actual tax benefit for the tax deductions from stock option exercises totaled $25 million , $46 million , and $19 million for the years ended December 31, 2017 , 2016 , and 2015 , respectively. Prior to the adoption of ASU 2016-09, the excess tax benefits related to the exercise of stock options were recognized in Southern Company's financial statements with a credit to equity. Upon the adoption of ASU 2016-09, beginning in 2016, all tax benefits related to the exercise of stock options are recognized in income.

Southern Company has a policy of issuing shares to satisfy share option exercises. Cash received from issuances related to option exercises under the share-based payment arrangements for the years ended December 31, 2017 , 2016 , and 2015 was $239 million , $448 million , and $154 million , respectively.

***Southern Company Gas Restricted Stock Awards***

At the effective time of the Merger, each outstanding award of existing Southern Company Gas performance share units was converted into an award of Southern Company's restricted stock units. Under the terms of the restricted stock awards, the employees received Southern Company stock when they satisfy the requisite service period by being continuously employed through the original three -year vesting schedule of the award being replaced. Southern Company issued 0.7 million restricted stock units with a grant-date fair value of $53.83 , based on the closing stock price of Southern Company common stock on the date of the grant. As a portion of the fair value of the award related to pre-combination service, the grant date fair value was allocated to pre- or post-combination service and accounted for as Merger consideration or compensation cost, respectively. Approximately $13 million of the grant date fair value was allocated to Merger consideration.

For the years ended December 31, 2017 and 2016, total compensation cost for restricted stock units recognized in income was $8 million and $13 million , respectively, and the related tax benefit also recognized in income was $4 million for each year. As of December 31, 2017, $3 million of total unrecognized compensation cost related to restricted stock units will be recognized over a weighted-average period of approximately 12 months .

***Southern Company Gas Change in Control Awards***

Southern Company awarded performance share units to certain Southern Company Gas employees who continued their employment with the Southern Company in lieu of certain change in control benefits the employee was entitled to receive following the Merger (change in control awards). Shares of Southern Company common stock and/or cash equal to the dollar value of the change in control benefit will vest and be issued one-third each year as long as the employee remains in service with Southern Company or its subsidiaries at each vest date. In addition to the change in control benefit, Southern Company common stock could be issued to the employees at the end of a performance period based on achievement of certain Southern Company common stock price metrics, as well performance goals established by the Compensation Committee of the Southern Company Board of Directors (achievement shares).

The change in control benefits are accounted for as a liability award with the fair value equal to the guaranteed dollar value of the change in control benefit. The grant-date fair value of the achievement portion of the award was determined using a Monte Carlo simulation model to estimate the number of achievement shares expected to vest based on the Southern Company common stock price. The expected payout is reevaluated annually with expense recognized to date increased or decreased proportionately based on the expected performance. The compensation expense ultimately recognized for the achievement shares will be based on the actual performance.

For the years ended December 31, 2017 and 2016, total compensation cost for the change in control awards recognized in income was $12 million and $4 million , respectively. The related tax benefit also recognized in income was $6 million for the year ended December 31, 2017 and an immaterial amount for the year ended December 31, 2016. As of December 31, 2017, approximately $8 million of total unrecognized compensation cost related to change in control awards will be recognized over a weighted-average period of approximately 18 months .

**Diluted Earnings Per Share**

For Southern Company, the only difference in computing basic and diluted EPS is attributable to awards outstanding under the stock option and performance share plans. The effect of both stock options and performance share award units was determined using the treasury stock method. Shares used to compute diluted EPS were as follows:

| | Average Common Stock Shares | | |
|---|---|---|---|
| | **2017** | 2016 | 2015 |
| | | *(in millions)* | |
| As reported shares | **1,000** | 951 | 910 |
| Effect of options and performance share award units | **8** | 7 | 4 |
| Diluted shares | **1,008** | 958 | 914 |

Prior to the adoption of ASU 2016-09 in 2016 , the effect of options and performance share award units included the assumed impacts of any excess tax benefits from the exercise of all "in the money" outstanding share based awards. Stock options and performance share award units that were not included in the diluted EPS calculation because they were anti-dilutive were immaterial in all years presented.

**Common Stock Dividend Restrictions**

The income of Southern Company is derived primarily from equity in earnings of its subsidiaries. At December 31, 2017 , consolidated retained earnings included $5.3 billion of undistributed retained earnings of the subsidiaries.

## 9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), Alabama Power and Georgia Power maintain agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the companies' nuclear power plants. The Act provides funds up to $13.4 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $450 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. A company could be assessed up to $127 million per incident for each licensed reactor it operates but not more than an aggregate of $19 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for Alabama Power and Georgia Power, based on its ownership and buyback interests in all licensed reactors, is $255 million and $247 million , respectively, per incident, but not more than an aggregate of $38 million and $37 million , respectively, per company to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years . The next scheduled adjustment is due no later than September 10, 2018. See Note 4 for additional information on joint ownership agreements.

Alabama Power and Georgia Power are members of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $1.5 billion for members' operating nuclear generating facilities. Additionally, both companies have NEIL policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $1.25 billion for nuclear losses and policies providing coverage up to $750 million for non-nuclear losses in excess of the $1.5 billion primary coverage.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks , with a maximum per occurrence per unit limit of $490 million . After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted. Alabama Power and Georgia Power each purchase limits based on the projected full cost of replacement power, subject to ownership limitations. Each facility has elected a 12-week deductible waiting period.

A builders' risk property insurance policy has been purchased from NEIL for the construction of Plant Vogtle Units 3 and 4. This policy provides the Vogtle Owners up to $2.75 billion for accidental property damage occurring during construction.

Under each of the NEIL policies, members are subject to assessments each year if losses exceed the accumulated funds available to the insurer. The maximum annual assessments for Alabama Power and Georgia Power as of December 31, 2017 under the NEIL policies would be $55 million and $81 million , respectively.

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the applicable company or to its debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by Alabama Power or Georgia Power, as applicable, and could have a material effect on Southern Company's financial condition and results of operations.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

## 10. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

**NOTES (continued)**
**Southern Company and Subsidiary Companies 2017 Annual Report**

As of December 31, 2017 , assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| As of December 31, 2017: | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Net Asset Value as a Practical Expedient (NAV) | Total |
| | | | *(in millions)* | | |
| Assets: | | | | | |
| Energy-related derivatives [(a)(b)] | $ 331 | $ 239 | $ — | $ — | $ 570 |
| Interest rate derivatives | — | 1 | — | — | 1 |
| Foreign currency derivatives | — | 129 | — | — | 129 |
| Nuclear decommissioning trusts: [(c)] | | | | | |
| Domestic equity | 690 | 82 | — | — | 772 |
| Foreign equity | 62 | 224 | — | — | 286 |
| U.S. Treasury and government agency securities | — | 251 | — | — | 251 |
| Municipal bonds | — | 68 | — | — | 68 |
| Corporate bonds | 21 | 315 | — | — | 336 |
| Mortgage and asset backed securities | — | 57 | — | — | 57 |
| Private equity | — | — | — | 29 | 29 |
| Other | 19 | 12 | — | — | 31 |
| Cash equivalents | 1,455 | — | — | — | 1,455 |
| Other investments | 9 | — | 1 | — | 10 |
| Total | $ 2,587 | $ 1,378 | $ 1 | $ 29 | $ 3,995 |
| Liabilities: | | | | | |
| Energy-related derivatives [(a)(b)] | $ 480 | $ 253 | $ — | $ — | $ 733 |
| Interest rate derivatives | — | 38 | — | — | 38 |
| Foreign currency derivatives | — | 23 | — | — | 23 |
| Contingent consideration | — | — | 22 | — | 22 |
| Total | $ 480 | $ 314 | $ 22 | $ — | $ 816 |

(a) Energy-related derivatives exclude $11 million associated with premiums and certain weather derivatives accounted for based on intrinsic value rather than fair value.

(b) Energy-related derivatives exclude cash collateral of $193 million .

(c) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, currencies, and payables related to pending investment purchases and the securities lending program. See Note 1 under " Nuclear Decommissioning " for additional information.

As of December 31, 2016 , assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| As of December 31, 2016: | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Net Asset Value as a Practical Expedient (NAV) | Total |
| | | | *(in millions)* | | |
| Assets: | | | | | |
| Energy-related derivatives [(a)(b)] | $ 338 | $ 333 | $ — | $ — | $ 671 |
| Interest rate derivatives | — | 14 | — | — | 14 |
| Nuclear decommissioning trusts: [(c)] | | | | | |
| Domestic equity | 589 | 73 | — | — | 662 |
| Foreign equity | 48 | 168 | — | — | 216 |
| U.S. Treasury and government agency securities | — | 92 | — | — | 92 |
| Municipal bonds | — | 73 | — | — | 73 |
| Corporate bonds | 22 | 310 | — | — | 332 |
| Mortgage and asset backed securities | — | 183 | — | — | 183 |
| Private equity | — | — | — | 20 | 20 |
| Other | 11 | 15 | — | — | 26 |
| Cash equivalents | 1,172 | — | — | — | 1,172 |
| Other investments | 9 | — | 1 | — | 10 |
| Total | $ 2,189 | $ 1,261 | $ 1 | $ 20 | $ 3,471 |
| Liabilities: | | | | | |
| Energy-related derivatives [(a)(b)] | $ 345 | $ 285 | $ — | $ — | $ 630 |
| Interest rate derivatives | — | 29 | — | — | 29 |
| Foreign currency derivatives | — | 58 | — | — | 58 |
| Contingent consideration | — | — | 18 | — | 18 |
| Total | $ 345 | $ 372 | $ 18 | $ — | $ 735 |

(a) Energy-related derivatives exclude $4 million associated with certain weather derivatives accounted for based on intrinsic value rather than fair value.

(b) Energy-related derivatives exclude cash collateral of $62 million .

(c) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, currencies, and payables related to pending investment purchases and the securities lending program. See Note 1 under " Nuclear Decommissioning " for additional information.

### Valuation Methodologies

The energy-related derivatives primarily consist of exchange-traded and over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard over-the-counter products that are valued using observable market data and assumptions commonly used by market participants. The fair value of interest rate derivatives reflects the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk, and occasionally, implied volatility of interest rate options. The fair value of cross-currency swaps reflects the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future foreign currency exchange rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk, and discount rates. The interest rate derivatives and cross-currency swaps are categorized as Level 2 under Fair Value Measurements as these inputs are based on observable data and valuations of similar instruments. See Note 11 for additional information on how these derivatives are used.

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. For fair value measurements of the investments within the nuclear decommissioning trusts, external pricing vendors are designated for each asset class with each security specifically assigned a primary pricing source. For investments held within commingled funds, fair value is determined at the end of each business day through the net asset value, which is established by obtaining the underlying securities' individual prices from the primary pricing source. A market price secured from the primary source vendor is then evaluated by management in its valuation of the assets within the trusts. As a general approach, fixed income market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information, including live trading levels and pricing analysts' judgments, are also obtained when available. See Note 1 under " Nuclear Decommissioning " for additional information.

Southern Power has contingent payment obligations related to certain acquisitions whereby Southern Power is primarily obligated to make generation-based payments to the seller commencing at the commercial operation date through 2026. The obligation is categorized as Level 3 under Fair Value Measurements as the fair value is determined using significant unobservable inputs for the forecasted facility generation in MW-hours, as well as other inputs such as a fixed dollar amount per MW-hour, and a discount rate, and is evaluated periodically. The fair value of contingent consideration reflects the net present value of expected payments and any periodic change arising from forecasted generation is expected to be immaterial.

"Other investments" include investments that are not traded in the open market. The fair value of these investments has been determined based on market factors including comparable multiples and the expectations regarding cash flows and business plan executions.

As of December 31, 2017 and 2016 , the fair value measurements of private equity investments held in the nuclear decommissioning trust that are calculated at net asset value per share (or its equivalent) as a practical expedient, as well as the nature and risks of those investments, were as follows:

| | Fair Value | Unfunded Commitments | Redemption Frequency | Redemption Notice Period |
|---|---|---|---|---|
| | *(in millions)* | | | |
| **As of December 31, 2017** | **$ 29** | **$ 21** | **Not Applicable** | **Not Applicable** |
| As of December 31, 2016 | $ 20 | $ 25 | Not Applicable | Not Applicable |

Private equity funds include a fund-of-funds that invests in high-quality private equity funds across several market sectors, funds that invest in real estate assets, and a fund that acquires companies to create resale value. Private equity funds do not have redemption rights. Distributions from these funds will be received as the underlying investments in the funds are liquidated. Liquidations are expected to occur at various times over the next 10 years .

As of December 31, 2017 and 2016 , other financial instruments for which the carrying amount did not equal fair value were as follows:

| | Carrying Amount | Fair Value |
|---|---|---|
| | *(in millions)* | |
| Long-term debt, including securities due within one year: | | |
| **2017** | **$ 48,151** | **$ 51,348** |
| 2016 | $ 45,080 | $ 46,286 |

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates available to Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and Southern Company Gas.

## 11. DERIVATIVES

The Southern Company system is exposed to market risks, including commodity price risk, interest rate risk, weather risk, and occasionally foreign currency exchange rate risk. To manage the volatility attributable to these exposures, each company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to each company's policies in areas such as counterparty exposure and risk management practices. Southern Company Gas' wholesale gas operations use various contracts in its commercial activities that generally meet the definition of derivatives. For the traditional electric operating companies, Southern Power, and Southern Company Gas' other businesses, each company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a net basis. See Note 10 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities. The cash impacts of settled foreign currency derivatives are classified as operating or financing activities to correspond with classification of the hedged interest or principal, respectively. See Note 1 under " Financial Instruments " for additional information.

**Energy-Related Derivatives**

Southern Company and certain subsidiaries enter into energy-related derivatives to hedge exposures to electricity, natural gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the traditional electric operating companies and natural gas distribution utilities have limited exposure to market volatility in energy-related commodity prices. Each of the traditional electric operating companies and certain of the natural gas distribution utilities manage fuel-hedging programs, implemented per the guidelines of their respective state PSCs or other applicable state regulatory agencies, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility. The traditional electric operating companies (with respect to wholesale generating capacity) and Southern Power have limited exposure to market volatility in energy-related commodity prices because their long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, the traditional electric operating companies and Southern Power may be exposed to market volatility in energy-related commodity prices to the extent any uncontracted capacity is used to sell electricity. Southern Company Gas retains exposure to price changes that can, in a volatile energy market, adversely affect results of operations.

Southern Company Gas also enters into weather derivative contracts as economic hedges of adjusted operating margins in the event of warmer-than-normal weather. Exchange-traded options are carried at fair value, with changes reflected in operating revenues. Non-exchange-traded options are accounted for using the intrinsic value method. Changes in the intrinsic value for non-exchange-traded contracts are reflected in the statements of income.

Energy-related derivative contracts are accounted for under one of three methods:

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the traditional electric operating companies' and natural gas distribution utilities' fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the respective fuel cost recovery clauses.
- *Cash Flow Hedges* – Gains and losses on energy-related derivatives designated as cash flow hedges (which are mainly used to hedge anticipated purchases and sales) are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric and natural gas industries. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2017 , the net volume of energy-related derivative contracts for natural gas positions totaled 621 million mmBtu for the Southern Company system, with the longest hedge date of 2021 over which the respective entity is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest non-hedge date of 2026 for derivatives not designated as hedges.

In addition to the volumes discussed above, the traditional electric operating companies and Southern Power enter into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 32 million mmBtu.

The estimated pre-tax gains (losses) related to energy-related derivatives that will be reclassified from accumulated OCI to earnings for the 12-month period ending December 31, 2018 total $(11) million for Southern Company.

**Interest Rate Derivatives**

Southern Company and certain subsidiaries may also enter into interest rate derivatives to hedge exposure to changes in interest rates. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings, with any ineffectiveness recorded directly to earnings. Derivatives related to existing fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains or losses and hedged items' fair value gains or losses are both recorded directly to earnings, providing an offset, with any difference representing ineffectiveness. Fair value gains or losses on derivatives that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

At December 31, 2017 , the following interest rate derivatives were outstanding:

| | Notional Amount | Interest Rate Received | Weighted Average Interest Rate Paid | Hedge Maturity Date | Fair Value Gain (Loss) December 31, 2017 |
|---|---|---|---|---|---|
| | *(in millions)* | | | | *(in millions)* |
| ***Cash Flow Hedges of Existing Debt*** | | | | | |
| | $ 900 | 1-month LIBOR | 0.79% | March 2018 | $ 1 |
| ***Fair Value Hedges of Existing Debt*** | | | | | |
| | 250 | 5.40% | 3-month LIBOR + 4.02% | June 2018 | — |
| | 500 | 1.95% | 3-month LIBOR + 0.76% | December 2018 | (3) |
| | 200 | 4.25% | 3-month LIBOR + 2.46% | December 2019 | (1) |
| | 300 | 2.75% | 3-month LIBOR + 0.92% | June 2020 | (2) |
| | 1,500 | 2.35% | 1-month LIBOR + 0.87% | July 2021 | (31) |
| Total | $ 3,650 | | | | $ (36) |

The estimated pre-tax gains (losses) related to interest rate derivatives expected to be reclassified from accumulated OCI to interest expense for the next 12 -month period ending December 31, 2018 total $(20) million . Deferred gains and losses are expected to be amortized into earnings through 2046 .

**Foreign Currency Derivatives**

Southern Company and certain subsidiaries may also enter into foreign currency derivatives to hedge exposure to changes in foreign currency exchange rates, such as that arising from the issuance of debt denominated in a currency other than U.S. dollars. Derivatives related to forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time that the hedged transactions affect earnings, including foreign currency gains or losses arising from changes in the U.S. currency exchange rates. Any ineffectiveness is recorded directly to earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness.

At December 31, 2017 , the following foreign currency derivatives were outstanding:

| | Pay Notional | Pay Rate | Receive Notional | Receive Rate | Hedge Maturity Date | Fair Value Gain (Loss) at December 31, 2017 |
|---|---|---|---|---|---|---|
| | *(in millions)* | | *(in millions)* | | | *(in millions)* |
| ***Cash Flow Hedges of Existing Debt*** | | | | | | |
| | $ 677 | 2.95% | € 600 | 1.00% | June 2022 | $ 55 |
| | 564 | 3.78% | 500 | 1.85% | June 2026 | 51 |
| Total | $ 1,241 | | € 1,100 | | | $ 106 |

The estimated pre-tax gains (losses) related to foreign currency derivatives that will be reclassified from accumulated OCI to earnings for the next 12 -month period ending December 31, 2018 total $(23) million .

**Derivative Financial Statement Presentation and Amounts**

Southern Company and its subsidiaries enter into derivative contracts that may contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Southern Company and certain subsidiaries also utilize master netting agreements to mitigate exposure to counterparty credit risk. These agreements may contain provisions that permit netting across product lines and against cash collateral. Fair value amounts of derivative assets and liabilities on the balance sheets are presented net to the extent that there are netting arrangements or similar agreements with the counterparties.

At December 31, 2017 and 2016 , the fair value of energy-related derivatives, interest rate derivatives, and foreign currency derivatives was reflected in the balance sheets as follows:

| | 2017 | | 2016 | |
|---|---|---|---|---|
| **Derivative Category and Balance Sheet Location** | **Assets** | **Liabilities** | Assets | Liabilities |
| | | *(in millions)* | | |
| **Derivatives designated as hedging instruments for regulatory purposes** | | | | |
| Energy-related derivatives: | | | | |
| Other current assets/Other current liabilities | **$ 10** | **$ 43** | $ 73 | $ 27 |
| Other deferred charges and assets/Other deferred credits and liabilities | **7** | **24** | 25 | 33 |
| **Total derivatives designated as hedging instruments for regulatory purposes** | **$ 17** | **$ 67** | $ 98 | $ 60 |
| **Derivatives designated as hedging instruments in cash flow and fair value hedges** | | | | |
| Energy-related derivatives: | | | | |
| Other current assets/Other current liabilities | **$ 3** | **$ 14** | $ 23 | $ 7 |
| Interest rate derivatives: | | | | |
| Other current assets/Other current liabilities | **1** | **4** | 12 | 1 |
| Other deferred charges and assets/Other deferred credits and liabilities | **—** | **34** | 1 | 28 |
| Foreign currency derivatives: | | | | |
| Other current assets/Other current liabilities | **—** | **23** | — | 25 |
| Other deferred charges and assets/Other deferred credits and liabilities | **129** | **—** | — | 33 |
| **Total derivatives designated as hedging instruments in cash flow and fair value hedges** | **$ 133** | **$ 75** | $ 36 | $ 94 |
| **Derivatives not designated as hedging instruments** | | | | |
| Energy-related derivatives: | | | | |
| Other current assets/Other current liabilities | **$ 380** | **$ 437** | $ 489 | $ 483 |
| Other deferred charges and assets/Other deferred credits and liabilities | **170** | **215** | 66 | 81 |
| Interest rate derivatives: | | | | |
| Other current assets/Other current liabilities | **—** | **—** | 1 | — |
| **Total derivatives not designated as hedging instruments** | **$ 550** | **$ 652** | $ 556 | $ 564 |
| **Gross amounts recognized** | **$ 700** | **$ 794** | $ 690 | $ 718 |
| **Gross amounts offset [(a)]** | **$ (405)** | **$ (598)** | $ (462) | $ (524) |
| **Net amounts recognized in the Balance Sheets [(b)]** | **$ 295** | **$ 196** | $ 228 | $ 194 |

(a) Gross amounts offset include cash collateral held on deposit in broker margin accounts of $193 million and $62 million as of December 31, 2017 and 2016 , respectively.

(b) Net amounts of derivative instruments outstanding exclude premiums and intrinsic value associated with weather derivatives of $11 million as of December 31, 2017.

**NOTES (continued)**
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At December 31, 2017 and 2016 , the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivatives designated as regulatory hedging instruments and deferred were as follows:

| | Unrealized Losses | | | Unrealized Gains | | |
|---|---|---|---|---|---|---|
| **Derivative Category** | **Balance Sheet Location** | **2017** | 2016 | **Balance Sheet Location** | **2017** | 2016 |
| | | *(in millions)* | | | *(in millions)* | |
| Energy-related derivatives: | Other regulatory assets, current | **$ (34)** | $ (16) | Other regulatory liabilities, current | **$ 7** | $ 56 |
| | Other regulatory assets, deferred | **(18)** | (19) | Other regulatory liabilities, deferred | **1** | 12 |
| **Total energy-related derivative gains (losses)** (*) | | **$ (52)** | $ (35) | | **$ 8** | $ 68 |

(*) Fair value gains and losses recorded in regulatory assets and liabilities include cash collateral held on deposit in broker margin accounts of $6 million and $8 million as of December 31, 2017 and 2016 , respectively.

For the years ended December 31, 2017 , 2016 , and 2015 , the pre-tax effects of energy-related derivatives, interest rate derivatives, and foreign currency derivatives designated as cash flow hedging instruments on the statements of income were as follows:

| **Derivatives in Cash Flow Hedging Relationships** | **Gain (Loss) Recognized in OCI on Derivative (Effective Portion)** | | | **Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)** | | | |
|---|---|---|---|---|---|---|---|
| | **Amount** | | | | **Amount** | | |
| **Derivative Category** | **2017** | 2016 | 2015 | **Statements of Income Location** | **2017** | 2016 | 2015 |
| | *(in millions)* | | | | *(in millions)* | | |
| Energy-related derivatives | **$ (47)** | $ 18 | $ — | Depreciation and amortization | **$ (16)** | $ 2 | $ — |
| | | | | Cost of natural gas | **(2)** | (1) | — |
| Interest rate derivatives | **(2)** | (180) | (22) | Interest expense, net of amounts capitalized | **(21)** | (18) | (9) |
| Foreign currency derivatives | **140** | (58) | — | Interest expense, net of amounts capitalized | **(23)** | (13) | — |
| | | | | Other income (expense), net (*) | **160** | (82) | — |
| Total | **$ 91** | $ (220) | $ (22) | | **$ 98** | $ (112) | $ (9) |

(*) The reclassification from accumulated OCI into other income (expense), net completely offsets currency gains and losses arising from changes in the U.S. currency exchange rates used to record euro-denominated notes.

There was no material ineffectiveness recorded in earnings for any period presented.

For the years ended December 31, 2017 , 2016 , and 2015 , the pre-tax effects of interest rate derivatives designated as fair value hedging instruments were as follows:

| **Derivatives in Fair Value Hedging Relationships** | | **Gain (Loss)** | | |
|---|---|---|---|---|
| **Derivative Category** | **Statements of Income Location** | **2017** | 2016 | 2015 |
| | | *(in millions)* | | |
| Interest rate derivatives: | Interest expense, net of amounts capitalized | **$ (22)** | $ (21) | $ 2 |

For all years presented, the pre-tax effects of interest rate derivatives designated as fair value hedging instruments were offset by changes to the carrying value of long-term debt.

**NOTES (continued)**
**Southern Company and Subsidiary Companies 2017 Annual Report**

For the years ended December 31, 2017 , 2016 , and 2015 , the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of income were as follows:

| **Derivatives Not Designated as Hedging Instruments** | | **Unrealized Gain (Loss) Recognized in Income** | | |
|---|---|---|---|---|
| | | **Amount** | | |
| **Derivative Category** | **Statements of Income Location** | **2017** | 2016 | 2015 |
| | | *(in millions)* | | |
| Energy-related derivatives | Wholesale electric revenues | **$ (4)** | $ 2 | $ (5) |
| | Fuel | **—** | — | 3 |
| | Natural gas revenues [*] | **(80)** | 33 | — |
| | Cost of natural gas | **(2)** | 3 | — |
| Total | | **$ (86)** | $ 38 | $ (2) |

(*) Excludes gains (losses) recorded in natural gas revenues associated with weather derivatives of $23 million and $6 million for the years ended December 31, 2017 and 2016 , respectively.

For the years ended December 31, 2017 , 2016 , and 2015 , the pre-tax effects of interest rate derivatives not designated as hedging instruments were immaterial.

**Contingent Features**

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain Southern Company subsidiaries. At December 31, 2017 , the Company had no collateral posted with derivative counterparties to satisfy these arrangements.

At December 31, 2017 , the fair value of energy-related and interest rate derivative liabilities with contingent features was $15 million and $7 million , respectively. The maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $14 million and $7 million for energy-related and interest rate derivative contracts, respectively.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

The Southern Company system maintains accounts with certain regional transmission organizations to facilitate financial derivative transactions. Based on the value of the positions in these accounts and the associated margin requirements, the Company may be required to post collateral. At December 31, 2017 , cash collateral posted in these accounts was immaterial. Southern Company Gas maintains accounts with brokers or the clearing houses of certain exchanges to facilitate financial derivative transactions. Based on the value of the positions in these accounts and the associated margin requirements, Southern Company may be required to deposit cash into these accounts. At December 31, 2017 , cash collateral held on deposit in broker margin accounts was $193 million .

Southern Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. Southern Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. Southern Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate Southern Company's exposure to counterparty credit risk. Southern Company may require counterparties to pledge additional collateral when deemed necessary.

In addition, Southern Company Gas conducts credit evaluations and obtains appropriate internal approvals for the counterparty's line of credit before any transaction with the counterparty is executed. In most cases, the counterparty must have an investment grade rating, which includes a minimum long-term debt rating of Baa3 from Moody's and BBB- from S&P. Generally, Southern Company Gas requires credit enhancements by way of a guaranty, cash deposit, or letter of credit for transaction counterparties that do not have investment grade ratings.

Southern Company Gas also utilizes master netting agreements whenever possible to mitigate exposure to counterparty credit risk. When Southern Company Gas is engaged in more than one outstanding derivative transaction with the same counterparty and it also has a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of Southern Company Gas' credit risk. Southern Company Gas also uses other netting agreements with certain counterparties with whom it conducts significant transactions. Master netting agreements enable Southern Company Gas to net certain assets and liabilities by counterparty. Southern Company Gas also nets across product lines and against cash collateral provided the master netting and cash collateral agreements include such provisions. Southern Company Gas may require counterparties to pledge additional collateral when deemed necessary.

Southern Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

## 12. ACQUISITIONS AND DISPOSITIONS

### Southern Company

#### *Merger with Southern Company Gas*

Southern Company Gas is an energy services holding company whose primary business is the distribution of natural gas through the natural gas distribution utilities. On July 1, 2016, Southern Company completed the Merger for a total purchase price of approximately $8.0 billion and Southern Company Gas became a wholly-owned, direct subsidiary of Southern Company.

The Merger was accounted for using the acquisition method of accounting with the assets acquired and liabilities assumed recognized at fair value as of the acquisition date. The following table presents the final purchase price allocation:

**Southern Company Gas Purchase Price**

| | | *(in millions)* |
|---|---|---|
| Current assets | $ | 1,557 |
| Property, plant, and equipment | | 10,108 |
| Goodwill | | 5,967 |
| Intangible assets | | 400 |
| Regulatory assets | | 1,118 |
| Other assets | | 229 |
| Current liabilities | | (2,201) |
| Other liabilities | | (4,742) |
| Long-term debt | | (4,261) |
| Noncontrolling interest | | (174) |
| Total purchase price | $ | 8,001 |

The excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed of $6.0 billion is recognized as goodwill, which is primarily attributable to positioning the Southern Company system to provide natural gas infrastructure to meet customers' growing energy needs and to compete for growth across the energy value chain. Southern Company anticipates that much of the value assigned to goodwill will not be deductible for tax purposes.

The valuation of identifiable intangible assets included customer relationships, trade names, and storage and transportation contracts with estimated lives of one to 28 years . The estimated fair value measurements of identifiable intangible assets were primarily based on significant unobservable inputs (Level 3).

The results of operations for Southern Company Gas have been included in Southern Company's consolidated financial statements from the date of acquisition and consist of operating revenues of $3.9 billion and $1.7 billion and net income of $243 million and $114 million for 2017 and 2016 , respectively.

The following summarized unaudited pro forma consolidated statement of earnings information assumes that the acquisition of Southern Company Gas was completed on January 1, 2015. The summarized unaudited pro forma consolidated statement of earnings information includes adjustments for (i) intercompany sales, (ii) amortization of intangible assets, (iii) adjustments to interest expense to reflect current interest rates on Southern Company Gas debt and additional interest expense associated with borrowings by Southern Company to fund the Merger, and (iv) the elimination of nonrecurring expenses associated with the Merger.

| | 2016 | 2015 |
|---|---|---|
| Operating revenues (in millions) | $ 21,791 | $ 21,430 |
| Net income attributable to Southern Company (in millions) | $ 2,591 | $ 2,665 |
| Basic EPS | $ 2.70 | $ 2.85 |
| Diluted EPS | $ 2.68 | $ 2.84 |

These unaudited pro forma results are for comparative purposes only and may not be indicative of the results that would have occurred had this acquisition been completed on January 1, 2015 or the results that would be attained in the future.

***Acquisition of PowerSecure***

In May 2016, Southern Company acquired all of the outstanding stock of PowerSecure, a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure, for $18.75 per common share in cash, resulting in an aggregate purchase price of $429 million . As a result, PowerSecure became a wholly-owned subsidiary of Southern Company.

The acquisition of PowerSecure was accounted for using the acquisition method of accounting with the assets acquired and liabilities assumed recognized at fair value as of the acquisition date. The following table presents the final purchase price allocation:

| PowerSecure Purchase Price | *(in millions)* |
|---|---|
| Current assets | $ 172 |
| Property, plant, and equipment | 46 |
| Intangible assets | 106 |
| Goodwill | 284 |
| Other assets | 4 |
| Current liabilities | (121) |
| Long-term debt, including current portion | (48) |
| Deferred credits and other liabilities | (14) |
| Total purchase price | $ 429 |

The excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed of $284 million was recognized as goodwill, which is primarily attributable to expected business expansion opportunities for PowerSecure. Southern Company anticipates that the majority of the value assigned to goodwill will not be deductible for tax purposes.

The valuation of identifiable intangible assets included customer relationships, trade names, patents, backlog, and software with estimated lives of one to 26 years . The estimated fair value measurements of identifiable intangible assets were primarily based on significant unobservable inputs (Level 3).

The results of operations for PowerSecure have been included in Southern Company's consolidated financial statements from the date of acquisition and are immaterial to the consolidated financial results of Southern Company. Pro forma results of operations have not been presented for the acquisition because the effects of the acquisition were immaterial to Southern Company's consolidated financial results for all periods presented.

**Southern Power**

During 2017 and 2016 , in accordance with its overall growth strategy, Southern Power or one of its wholly-owned subsidiaries, acquired or contracted to acquire the projects discussed below. Also, in March 2016, Southern Power acquired an additional 15% interest in Desert Stateline, 51% of which was initially acquired in 2015. As a result, Southern Power and the class B member are now entitled to 66% and 34% , respectively, of all cash distributions from Desert Stateline. In addition, Southern Power will continue to be entitled to substantially all of the federal tax benefits with respect to the transaction. Acquisition-related costs were expensed as incurred and were not material for any of the years presented.

The following table presents Southern Power's acquisition activity for the year ended, and subsequent to, December 31, 2017 .

| Project Facility | Resource | Seller; Acquisition Date | Approximate Nameplate Capacity (MW) | Location | Southern Power Percentage Ownership | Actual/Expected COD | PPA Contract Period |
|---|---|---|---|---|---|---|---|
| **Business Acquisitions During the Year Ended December 31, 2017** | | | | | | | |
| Bethel | Wind | Invenergy Wind Global LLC, January 6, 2017 | 276 | Castro County, TX | 100% | January 2017 | 12 years |
| Cactus Flats [(a)] | Wind | RES America Developments, Inc. July 31, 2017 | 148 | Concho County, TX | 100% | Third quarter 2018 | 12 years and 15 years |
| **Business Acquisitions Subsequent to December 31, 2017** | | | | | | | |
| Gaskell West 1 | Solar | Recurrent Energy Development Holdings, LLC, January 26, 2018 | 20 | Kern County, CA | 100% of Class B [(b)] | March 2018 | 20 years |

(a) On July 31, 2017, Southern Power purchased 100% of the Cactus Flats facility and commenced construction. Upon placing the facility in service, Southern Power expects to close on a tax equity partnership agreement that has already been executed, subject to various customary conditions at closing, and will then own 100% of the class B membership interests.

(b) Southern Power owns 100% of the class B membership interest under a tax equity partnership agreement.

***Business Acquisitions During the Year Ended December 31, 2017***

Southern Power's aggregate purchase price for acquisitions during the year ended December 31, 2017 was $539 million . The fair values of the assets acquired and liabilities assumed were finalized in 2017 and recorded as follows:

| | 2017 | |
|---|---|---|
| | *(in millions)* | |
| Restricted cash | $ | 16 |
| CWIP | | 534 |
| Other assets | | 5 |
| Accounts payable | | (16) |
| Total purchase price | $ | 539 |

In 2017, total revenues of $15 million and net income of $17 million , primarily as a result of PTCs, was recognized by Southern Power related to the 2017 acquisitions. The Bethel facility did not have operating revenues or activities prior to completion of construction and being placed in service, and the Cactus Flats facility is still under construction. Therefore, supplemental pro forma information as though the acquisitions occurred as of the beginning of 2017 and for the comparable 2016 period is not meaningful and has been omitted.

***Construction Projects in Progress***

During the year ended December 31, 2017 , in accordance with its overall growth strategy, Southern Power continued construction on the 345 -MW Mankato expansion project and commenced construction on the Cactus Flats facility. Total aggregate construction costs for these facilities, excluding acquisition costs and including construction costs to complete the subsequently-acquired Gaskell West 1 solar project, are expected to be between $385 million and $430 million . At December 31, 2017, construction costs included in CWIP related to these projects totaled $188 million . The ultimate outcome of these matters cannot be determined at this time.

***Development Projects***

During 2017, as part of Southern Power's renewable development strategy, Southern Power purchased wind turbine equipment from Siemens Wind Power, Inc. and Vestas-American Wind Technology, Inc. to be used for various development and construction projects, up to 900 MWs in total. Once these wind projects reach commercial operations, which is expected in 2021, they are expected to qualify for 80% PTCs.

During 2016, Southern Power entered into a joint development agreement with Renewable Energy Systems Americas, Inc. to develop and construct approximately 3,000 MWs of wind projects expected to be placed in service between 2018 and 2020. In addition, in 2016, Southern Power purchased wind turbine equipment from Siemens Wind Power, Inc. and Vestas-American Wind Technology, Inc. to be used for construction of the facilities. Once these wind projects reach commercial operations, they are expected to qualify for 100% PTCs.

The ultimate outcome of these matters cannot be determined at this time.

The following table presents Southern Power's acquisitions for the year ended December 31, 2016 .

| Project Facility | Resource | Seller, Acquisition Date | Approximate Nameplate Capacity ( *MW* ) | Location | Ownership Percentage | Actual COD | PPA Contract Period |
|---|---|---|---|---|---|---|---|
| **Acquisitions for the Year Ended December 31, 2016** | | | | | | | |
| Boulder 1 | Solar | SunPower November 16, 2016 | 100 | Clark County, NV | 51% [(a)] | December 2016 | 20 years |
| Calipatria | Solar | Solar Frontier Americas Holding LLC February 11, 2016 | 20 | Imperial County, CA | 100% [(b)] | February 2016 | 20 years |
| East Pecos | Solar | First Solar, Inc. March 4, 2016 | 120 | Pecos County, TX | 100% | March 2017 | 15 years |
| Grant Plains | Wind | Apex Clean Energy Holdings, LLC August 26, 2016 | 147 | Grant County, OK | 100% | December 2016 | 20 years and 12 years [(c)] |
| Grant Wind | Wind | Apex Clean Energy Holdings, LLC April 7, 2016 | 151 | Grant County, OK | 100% | April 2016 | 20 years |
| Henrietta | Solar | SunPower July 1, 2016 | 102 | Kings County, CA | 51% [(a)] | July 2016 | 20 years |
| Lamesa | Solar | RES America Developments Inc. July 1, 2016 | 102 | Dawson County, TX | 100% | April 2017 | 15 years |
| Mankato [(d)] | Natural Gas | Calpine Corporation October 26, 2016 | 375 | Mankato, MN | 100% | N/A [(e)] | 10 years |
| Passadumkeag | Wind | Quantum Utility Generation, LLC June 30, 2016 | 42 | Penobscot County, ME | 100% | July 2016 | 15 years |
| Rutherford | Solar | Cypress Creek Renewables, LLC July 1, 2016 | 74 | Rutherford County, NC | 100% [(b)] | December 2016 | 15 years |
| Salt Fork | Wind | EDF Renewable Energy, Inc. December 1, 2016 | 174 | Donley and Gray Counties, TX | 100% | December 2016 | 14 years and 12 years |
| Tyler Bluff | Wind | EDF Renewable Energy, Inc. December 21, 2016 | 125 | Cooke County, TX | 100% | December 2016 | 12 years |
| Wake Wind | Wind | Invenergy October 26, 2016 | 257 | Floyd and Crosby Counties, TX | 90.1% [(f)] | October 2016 | 12 years |

(a) Southern Power owns 100% of the class A membership interests and a wholly-owned subsidiary of the seller owns 100% of the class B membership interests. Southern Power and the class B member are entitled to 51% and 49% , respectively, of all cash distributions from the project. In addition, Southern Power is entitled to substantially all of the federal tax benefits with respect to the transaction.
(b) Southern Power originally purchased 90% , with a minority owner owning 10% . During 2017, Southern Power acquired the remaining 10% ownership interest.
(c) In addition to the 20 -year and 12 -year PPAs, the facility has a 10 -year contract with Allianz Risk Transfer (Bermuda) Ltd.
(d) Under the terms of the PPA and the expansion PPA, approximately $442 million of assets, primarily related to property, plant, and equipment, are subject to lien at December 31, 2017.
(e) The acquisition included a fully operational 375 -MW natural gas-fired combined-cycle facility.
(f) Southern Power owns 90.1% , with the minority owner, Invenergy Wind Global LLC, owning 9.9% .

### *Acquisitions During the Year Ended December 31, 2016*

Southern Power's aggregate purchase price for acquisitions during the year ended December 31, 2016 was approximately $2.3 billion . The total aggregate purchase price including minority ownership contributions and the assumption of non-recourse construction debt to Southern Power was approximately $2.6 billion for these acquisitions. In connection with Southern Power's 2016 acquisitions, allocations of the purchase price to individual assets were finalized during the year ended December 31, 2017 with no changes to amounts originally reported for Boulder 1, Grant Plains, Grant Wind, Henrietta, Mankato, Passadumkeag, Salt Fork, Tyler Bluff, and Wake Wind. The fair values of the assets and liabilities acquired through the business combinations were recorded as follows:

| | | 2016 |
|---|---|---|
| | | *(in millions)* |
| CWIP | $ | 2,354 |
| Property, plant, and equipment | | 302 |
| Intangible assets [(a)] | | 128 |
| Other assets | | 52 |
| Accounts payable | | (16) |
| Debt | | (217) |
| Total purchase price | $ | 2,603 |
| | | |
| Funded by: | | |
| Southern Power [(b)] [(c)] | $ | 2,345 |
| Noncontrolling interests [(d)] [(e)] | | 258 |
| Total purchase price | $ | 2,603 |

(a) Intangible assets consist of acquired PPAs that will be amortized over 10 - and 20 -year terms. The estimated amortization for future periods is approximately $9 million per year. See Note 1 for additional information.

(b) At December 31, 2016, $461 million is included in acquisitions payable on the balance sheets.

(c) Includes approximately $281 million of contingent consideration, of which $29 million was payable at December 31, 2017.

(d) Includes approximately $51 million of non-cash contributions recorded as capital contributions from noncontrolling interests in the statements of stockholders' equity.

(e) Includes approximately $142 million of contingent consideration, all of which had been paid at December 31, 2016 by the noncontrolling interests.

## Southern Company Gas

### *Investment in Southern Natural Gas*

In September 2016, Southern Company Gas completed its acquisition from Kinder Morgan, Inc. of a 50% equity interest in Southern Natural Gas Company, L.L.C. (SNG), which is the owner of a 7,000 -mile pipeline system connecting natural gas supply basins in Texas, Louisiana, Mississippi, and Alabama to markets in Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina, and Tennessee. The purchase price of the acquisition was approximately $1.4 billion . The investment in SNG is accounted for using the equity method.

### *Acquisition of Remaining Interest in SouthStar*

SouthStar Energy Services, LLC (SouthStar) is a retail natural gas marketer and markets natural gas to residential, commercial, and industrial customers, primarily in Georgia and Illinois. Southern Company Gas previously had an 85% ownership interest in SouthStar, with Piedmont Natural Gas Company, Inc.'s (Piedmont) owning the remaining 15% . In October 2016, Southern Company Gas purchased Piedmont's 15% interest in SouthStar for $160 million .

### *Proposed Sale of Elizabethtown Gas and Elkton Gas*

On October 15, 2017, Southern Company Gas subsidiary, Pivotal Utility Holdings, entered into agreements for the sale of the assets of two of its natural gas distribution utilities, Elizabethtown Gas and Elkton Gas, to South Jersey Industries, Inc. for a total cash purchase price of $1.7 billion . The completion of each asset sale is subject to the satisfaction or waiver of certain conditions, including, among other customary closing conditions, the receipt of required regulatory approvals, including the FERC, the Federal Communications Commission, the New Jersey BPU, and, with respect to the sale of Elkton Gas, the Maryland PSC. Southern Company Gas and South Jersey Industries, Inc. made joint filings on December 22, 2017 and January 16, 2018 with the

New Jersey BPU and the Maryland PSC, respectively, requesting regulatory approval. The asset sales are expected to be completed by the end of the third quarter 2018.

The ultimate outcome of these matters cannot be determined at this time.

## 13. SEGMENT AND RELATED INFORMATION

The primary businesses of the Southern Company system are electricity sales by the traditional electric operating companies and Southern Power and the distribution of natural gas by Southern Company Gas. The four traditional electric operating companies – Alabama Power, Georgia Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. Southern Power develops, constructs, acquires, owns, and manages power generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Company Gas distributes natural gas through the natural gas distribution utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations.

Southern Company's reportable business segments are the sale of electricity by the four traditional electric operating companies, the sale of electricity in the competitive wholesale market by Southern Power, and the sale of natural gas and other complementary products and services by Southern Company Gas. Revenues from sales by Southern Power to the traditional electric operating companies were $392 million , $419 million , and $417 million in 2017 , 2016 , and 2015 , respectively. Revenues from sales of natural gas from Southern Company Gas to the traditional electric operating companies and Southern Power were $23 million and $119 million , respectively, in 2017 and $11 million and $17 million , respectively, in 2016 . The "All Other" column includes the Southern Company parent entity, which does not allocate operating expenses to business segments. Also, this category includes segments below the quantitative threshold for separate disclosure. These segments include providing energy technologies and services to electric utilities and large industrial, commercial, institutional, and municipal customers; as well as investments in telecommunications and leveraged lease projects. All other inter-segment revenues are not material. Financial data for business segments and products and services for the years ended December 31, 2017 , 2016 , and 2015 was as follows:

**NOTES (continued)**
**Southern Company and Subsidiary Companies 2017 Annual Report**

| | Electric Utilities | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Traditional Electric Operating Companies | Southern Power | Eliminations | Total | Southern Company Gas | All Other | Eliminations | Consolidated |
| | *(in millions)* | | | | | | | |
| **2017** | | | | | | | | |
| **Operating revenues** | **$ 16,884** | **$ 2,075** | **$ (419)** | **$ 18,540** | **$ 3,920** | **$ 741** | **$ (170)** | **$ 23,031** |
| **Depreciation and amortization** | **1,954** | **503** | **—** | **2,457** | **501** | **52** | **—** | **3,010** |
| **Interest income** | **14** | **7** | **—** | **21** | **3** | **11** | **(9)** | **26** |
| **Earnings from equity method investments** | **1** | **—** | **—** | **1** | **106** | **(1)** | **—** | **106** |
| **Interest expense** | **820** | **191** | **—** | **1,011** | **200** | **490** | **(7)** | **1,694** |
| **Income taxes** | **1,021** | **(939)** | **—** | **82** | **367** | **(307)** | **—** | **142** |
| **Segment net income (loss)** [(a)(b)(c)] | **(193)** | **1,071** | **—** | **878** | **243** | **(279)** | **—** | **842** |
| **Total assets** | **72,204** | **15,206** | **(325)** | **87,085** | **22,987** | **2,552** | **(1,619)** | **111,005** |
| **Gross property additions** | **3,836** | **268** | **—** | **4,104** | **1,525** | **355** | **—** | **5,984** |
| 2016 | | | | | | | | |
| Operating revenues | $ 16,803 | $ 1,577 | $ (439) | $ 17,941 | $ 1,652 | $ 463 | $ (160) | $ 19,896 |
| Depreciation and amortization | 1,881 | 352 | — | 2,233 | 238 | 31 | — | 2,502 |
| Interest income | 6 | 7 | — | 13 | 2 | 20 | (15) | 20 |
| Earnings from equity method investments | 2 | — | — | 2 | 60 | (3) | — | 59 |
| Interest expense | 814 | 117 | — | 931 | 81 | 317 | (12) | 1,317 |
| Income taxes | 1,286 | (195) | — | 1,091 | 76 | (216) | — | 951 |
| Segment net income (loss) [(a) (b)] | 2,233 | 338 | — | 2,571 | 114 | (230) | (7) | 2,448 |
| Total assets | 72,141 | 15,169 | (316) | 86,994 | 21,853 | 2,474 | (1,624) | 109,697 |
| Gross property additions | 4,852 | 2,114 | — | 6,966 | 618 | 41 | (1) | 7,624 |
| 2015 | | | | | | | | |
| Operating revenues | $ 16,491 | $ 1,390 | $ (439) | $ 17,442 | $ — | $ 152 | $ (105) | $ 17,489 |
| Depreciation and amortization | 1,772 | 248 | — | 2,020 | — | 14 | — | 2,034 |
| Interest income | 19 | 2 | 1 | 22 | — | 6 | (5) | 23 |
| Earnings from equity method investments | 1 | — | — | 1 | — | (1) | — | — |
| Interest expense | 697 | 77 | — | 774 | — | 69 | (3) | 840 |
| Income taxes | 1,305 | 21 | — | 1,326 | — | (132) | — | 1,194 |
| Segment net income (loss) [(a) (b)] | 2,186 | 215 | — | 2,401 | — | (32) | (2) | 2,367 |
| Total assets | 69,052 | 8,905 | (397) | 77,560 | — | 1,819 | (1,061) | 78,318 |
| Gross property additions | 5,124 | 1,005 | — | 6,129 | — | 40 | — | 6,169 |

(a) Attributable to Southern Company.

(b) Segment net income (loss) for the traditional electric operating companies includes pre-tax charges for estimated probable losses on the Kemper IGCC of $3.4 billion ( $2.4 billion after tax) in 2017, $428 million ( $264 million after tax) in 2016, and $365 million ( $226 million after tax) in 2015. See Note 3 under " Kemper County Energy Facility – Schedule and Cost Estimate " for additional information.

(c) Segment net income (loss) for the traditional electric operating companies also includes a pre-tax charge for the write-down of Gulf Power's ownership of Plant Scherer Unit 3 of $33 million ( $20 million after tax) in 2017. See Note 3 under "Regulatory Matters – Gulf Power – Retail Base Rate Cases" for additional information.

**Products and Services**

**Electric Utilities' Revenues**

| Year | Retail | Wholesale | Other | Total |
|---|---|---|---|---|
| | *(in millions)* | | | |
| **2017** | **$ 15,330** | **$ 2,426** | **$ 784** | **$ 18,540** |
| 2016 | 15,234 | 1,926 | 781 | 17,941 |
| 2015 | 14,987 | 1,798 | 657 | 17,442 |

**Southern Company Gas' Revenues**

| Year | Gas Distribution Operations | Gas Marketing Services | All Other | Total |
|---|---|---|---|---|
| | *(in millions)* | | | |
| **2017** | **$ 3,024** | **$ 860** | **$ 36** | **$ 3,920** |
| 2016 | 1,266 | 354 | 32 | 1,652 |

## 14. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2017 and 2016 is as follows:

| | | | | Per Common Share | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | Trading Price Range | |
| **Quarter Ended** | **Operating Revenues** | **Operating Income** | **Consolidated Net Income Attributable to Southern Company** | **Basic Earnings** | **Diluted Earnings** | **Dividends** | **High** | **Low** |
| | | *(in millions)* | | | | | | |
| **March 2017** | **$ 5,771** | **$ 1,306** | **$ 658** | **$ 0.66** | **$ 0.66** | **$ 0.5600** | **$ 51.47** | **$ 47.57** |
| **June 2017** | **5,430** | **(1,594)** | **(1,381)** | **(1.38)** | **(1.37)** | **0.5800** | **51.97** | **47.87** |
| **September 2017** | **6,201** | **2,045** | **1,069** | **1.07** | **1.06** | **0.5800** | **50.80** | **46.71** |
| **December 2017** | **5,629** | **794** | **496** | **0.49** | **0.49** | **0.5800** | **53.51** | **47.92** |
| | | | | | | | | |
| March 2016 | $ 3,992 | $ 940 | $ 489 | $ 0.53 | $ 0.53 | $ 0.5425 | $ 51.73 | $ 46.00 |
| June 2016 | 4,459 | 1,185 | 623 | 0.67 | 0.66 | 0.5600 | 53.64 | 47.62 |
| September 2016 | 6,264 | 1,917 | 1,139 | 1.18 | 1.17 | 0.5600 | 54.64 | 50.00 |
| December 2016 | 5,181 | 587 | 197 | 0.20 | 0.20 | 0.5600 | 52.23 | 46.20 |

As a result of the revisions to the cost estimate for the Kemper IGCC and its June 2017 suspension, Mississippi Power recorded total pre-tax charges to income related to the Kemper IGCC of $208 million ( $185 million after tax) in the fourth quarter 2017, $34 million ( $21 million after tax) in the third quarter 2017, $3.0 billion ( $2.1 billion after tax) in the second quarter 2017, $108 million ( $67 million after tax) in the first quarter 2017, $206 million ( $127 million after tax) in the fourth quarter 2016, $88 million ( $54 million after tax) in the third quarter 2016, $81 million ( $50 million after tax) in the second quarter 2016, and $53 million ( $33 million after tax) in the first quarter 2016. See Note 3 under " Kemper County Energy Facility " for additional information.

As a result of the Tax Reform Legislation, the Southern Company system recorded a total income tax benefit of $264 million in the fourth quarter 2017. See Note 5 for additional information.

The Southern Company system's business is influenced by seasonal weather conditions.

**SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA**
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| | | 2017 | | 2016 [(a)] | | 2015 | | 2014 | | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Operating Revenues (in millions)** | **$** | **23,031** | $ | 19,896 | $ | 17,489 | $ | 18,467 | $ | 17,087 |
| **Total Assets (in millions) [(b)(c)]** | **$** | **111,005** | $ | 109,697 | $ | 78,318 | $ | 70,233 | $ | 64,264 |
| **Gross Property Additions (in millions)** | **$** | **5,984** | $ | 7,624 | $ | 6,169 | $ | 6,522 | $ | 5,868 |
| **Return on Average Common Equity (percent) [(d)]** | | **3.44** | | 10.80 | | 11.68 | | 10.08 | | 8.82 |
| **Cash Dividends Paid Per Share of Common Stock** | **$** | **2.3000** | $ | 2.2225 | $ | 2.1525 | $ | 2.0825 | $ | 2.0125 |
| **Consolidated Net Income Attributable to Southern Company (in millions) [(d)]** | **$** | **842** | $ | 2,448 | $ | 2,367 | $ | 1,963 | $ | 1,644 |
| **Earnings Per Share —** | | | | | | | | | | |
| Basic | **$** | **0.84** | $ | 2.57 | $ | 2.60 | $ | 2.19 | $ | 1.88 |
| Diluted | | **0.84** | | 2.55 | | 2.59 | | 2.18 | | 1.87 |
| **Capitalization (in millions):** | | | | | | | | | | |
| Common stock equity | **$** | **24,167** | $ | 24,758 | $ | 20,592 | $ | 19,949 | $ | 19,008 |
| Preferred and preference stock of subsidiaries and noncontrolling interests | | **1,361** | | 1,854 | | 1,390 | | 977 | | 756 |
| Redeemable preferred stock of subsidiaries | | **324** | | 118 | | 118 | | 375 | | 375 |
| Redeemable noncontrolling interests | | **—** | | 164 | | 43 | | 39 | | — |
| Long-term debt [(b)] | | **44,462** | | 42,629 | | 24,688 | | 20,644 | | 21,205 |
| Total (excluding amounts due within one year) | **$** | **70,314** | $ | 69,523 | $ | 46,831 | $ | 41,984 | $ | 41,344 |
| **Capitalization Ratios (percent):** | | | | | | | | | | |
| Common stock equity | | **34.4** | | 35.6 | | 44.0 | | 47.5 | | 46.0 |
| Preferred and preference stock of subsidiaries and noncontrolling interests | | **1.9** | | 2.7 | | 3.0 | | 2.3 | | 1.8 |
| Redeemable preferred stock of subsidiaries | | **0.5** | | 0.2 | | 0.3 | | 0.9 | | 0.9 |
| Redeemable noncontrolling interests | | **—** | | 0.2 | | 0.1 | | 0.1 | | — |
| Long-term debt [(b)] | | **63.2** | | 61.3 | | 52.6 | | 49.2 | | 51.3 |
| Total (excluding amounts due within one year) | | **100.0** | | 100.0 | | 100.0 | | 100.0 | | 100.0 |
| **Other Common Stock Data:** | | | | | | | | | | |
| Book value per share | **$** | **23.99** | $ | 25.00 | $ | 22.59 | $ | 21.98 | $ | 21.43 |
| Market price per share: | | | | | | | | | | |
| High | **$** | **53.51** | $ | 54.64 | $ | 53.16 | $ | 51.28 | $ | 48.74 |
| Low | | **46.71** | | 46.00 | | 41.40 | | 40.27 | | 40.03 |
| Close (year-end) | | **48.09** | | 49.19 | | 46.79 | | 49.11 | | 41.11 |
| Market-to-book ratio (year-end) (percent) | | **200.5** | | 196.8 | | 207.2 | | 223.4 | | 191.8 |
| Price-earnings ratio (year-end) (times) | | **57.3** | | 19.1 | | 18.0 | | 22.4 | | 21.9 |
| Dividends paid (in millions) | **$** | **2,300** | $ | 2,104 | $ | 1,959 | $ | 1,866 | $ | 1,762 |
| Dividend yield (year-end) (percent) | | **4.8** | | 4.5 | | 4.6 | | 4.2 | | 4.9 |
| Dividend payout ratio (percent) | | **273.2** | | 86.0 | | 82.7 | | 95.0 | | 107.1 |
| Shares outstanding (in thousands): | | | | | | | | | | |
| Average | | **1,000,336** | | 951,332 | | 910,024 | | 897,194 | | 876,755 |
| Year-end | | **1,007,603** | | 990,394 | | 911,721 | | 907,777 | | 887,086 |
| Stockholders of record (year-end) | | **120,803** | | 126,338 | | 131,771 | | 137,369 | | 143,800 |

(a) The 2016 selected financial and operating data includes the operations of Southern Company Gas from the date of the Merger, July 1, 2016, through December 31, 2016. See Note 12 under "Merger with Southern Company Gas" for additional information.

(b) A reclassification of debt issuance costs from Total Assets to Long-term debt of $202 million and $139 million is reflected for years 2014 and 2013, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(c) A reclassification of deferred tax assets from Total Assets of $488 million and $143 million is reflected for years 2014 and 2013, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(d) A significant loss to income was recorded by Mississippi Power related to the suspension of the Kemper IGCC in June 2017. Earnings in all periods presented were impacted by losses related to the Kemper IGCC.

**SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA (continued)**
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| | 2017 | 2016 [(a)] | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|
| **Operating Revenues (in millions):** | | | | | |
| Residential | **$ 6,515** | $ 6,614 | $ 6,383 | $ 6,499 | $ 6,011 |
| Commercial | **5,439** | 5,394 | 5,317 | 5,469 | 5,214 |
| Industrial | **3,262** | 3,171 | 3,172 | 3,449 | 3,188 |
| Other | **114** | 55 | 115 | 133 | 128 |
| Total retail | **15,330** | 15,234 | 14,987 | 15,550 | 14,541 |
| Wholesale | **2,426** | 1,926 | 1,798 | 2,184 | 1,855 |
| Total revenues from sales of electricity | **17,756** | 17,160 | 16,785 | 17,734 | 16,396 |
| Natural gas revenues | **3,791** | 1,596 | — | — | — |
| Other revenues | **1,484** | 1,140 | 704 | 733 | 691 |
| Total | **$ 23,031** | $ 19,896 | $ 17,489 | $ 18,467 | $ 17,087 |
| **Kilowatt-Hour Sales (in millions):** | | | | | |
| Residential | **50,536** | 53,337 | 52,121 | 53,347 | 50,575 |
| Commercial | **52,340** | 53,733 | 53,525 | 53,243 | 52,551 |
| Industrial | **52,785** | 52,792 | 53,941 | 54,140 | 52,429 |
| Other | **846** | 883 | 897 | 909 | 902 |
| Total retail | **156,507** | 160,745 | 160,484 | 161,639 | 156,457 |
| Wholesale sales | **49,034** | 37,043 | 30,505 | 32,786 | 26,944 |
| Total | **205,541** | 197,788 | 190,989 | 194,425 | 183,401 |
| **Average Revenue Per Kilowatt-Hour (cents):** | | | | | |
| Residential | **12.89** | 12.40 | 12.25 | 12.18 | 11.89 |
| Commercial | **10.39** | 10.04 | 9.93 | 10.27 | 9.92 |
| Industrial | **6.18** | 6.01 | 5.88 | 6.37 | 6.08 |
| Total retail | **9.80** | 9.48 | 9.34 | 9.62 | 9.29 |
| Wholesale | **4.95** | 5.20 | 5.89 | 6.66 | 6.88 |
| Total sales | **8.64** | 8.68 | 8.79 | 9.12 | 8.94 |
| **Average Annual Kilowatt-Hour** | | | | | |
| **Use Per Residential Customer** | **11,618** | 12,387 | 13,318 | 13,765 | 13,144 |
| **Average Annual Revenue** | | | | | |
| **Per Residential Customer** | **$ 1,498** | $ 1,541 | $ 1,630 | $ 1,679 | $ 1,562 |
| **Plant Nameplate Capacity** | | | | | |
| **Ratings (year-end) (megawatts)** | **46,936** | 46,291 | 44,223 | 46,549 | 45,502 |
| **Maximum Peak-Hour Demand (megawatts):** | | | | | |
| Winter | **31,956** | 32,272 | 36,794 | 37,234 | 27,555 |
| Summer | **34,874** | 35,781 | 36,195 | 35,396 | 33,557 |
| **System Reserve Margin (at peak) (percent) [(b)]** | **30.8** | 34.2 | 33.2 | 19.8 | 21.5 |
| **Annual Load Factor (percent)** | **61.4** | 61.5 | 59.9 | 59.6 | 63.2 |
| **Plant Availability (percent):** | | | | | |
| Fossil-steam | **84.5** | 86.4 | 86.1 | 85.8 | 87.7 |
| Nuclear | **94.7** | 93.3 | 93.5 | 91.5 | 91.5 |

(a) The 2016 selected financial and operating data includes the operations of Southern Company Gas from the date of the Merger, July 1, 2016, through December 31, 2016. See Note 12 under "Merger with Southern Company Gas" for additional information.

(b) Beginning in 2014, system reserve margin is calculated to include unrecognized capacity.

**SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA (continued)**
**For the Periods Ended December 2013 through 2017**
**Southern Company and Subsidiary Companies 2017 Annual Report**

| | 2017 | 2016 [(a)] | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|
| **Source of Energy Supply (percent):** | | | | | |
| Coal | **27.0** | 30.3 | 32.3 | 39.3 | 36.9 |
| Nuclear | **14.5** | 14.5 | 15.2 | 14.8 | 15.5 |
| Oil and gas | **41.9** | 41.7 | 42.7 | 37.0 | 37.2 |
| Hydro | **2.1** | 2.1 | 2.6 | 2.5 | 3.9 |
| Other | **5.4** | 2.4 | 0.8 | 0.4 | 0.1 |
| Purchased power | **9.1** | 9.0 | 6.4 | 6.0 | 6.4 |
| Total | **100.0** | 100.0 | 100.0 | 100.0 | 100.0 |
| **Gas Sales Volumes (mmBtu in millions):** | | | | | |
| Firm | **667** | 296 | — | — | — |
| Interruptible | **95** | 53 | — | — | — |
| Total | **762** | 349 | — | — | — |
| **Traditional Electric Operating Company Customers (year-end) (in thousands):** | | | | | |
| Residential | **4,011** | 3,970 | 3,928 | 3,890 | 3,859 |
| Commercial [(b)] | **599** | 595 | 590 | 586 | 582 |
| Industrial [(b)] | **18** | 17 | 17 | 17 | 17 |
| Other | **12** | 11 | 11 | 11 | 9 |
| Total electric customers | **4,640** | 4,593 | 4,546 | 4,504 | 4,467 |
| Gas distribution operations customers | **4,623** | 4,586 | — | — | — |
| Total utility customers | **9,263** | 9,179 | 4,546 | 4,504 | 4,467 |
| **Employees (year-end)** | **31,344** | 32,015 | 26,703 | 26,369 | 26,300 |

(a) The 2016 selected financial and operating data includes the operations of Southern Company Gas from the date of the Merger, July 1, 2016, through December 31, 2016. See Note 12 under "Merger with Southern Company Gas" for additional information.

(b) A reclassification of customers from commercial to industrial is reflected for years 2013-2015 to be consistent with the rate structure approved by the Georgia PSC. The impact to operating revenues, kilowatt-hour sales, and average revenue per kilowatt-hour by class is not material.

# ALABAMA POWER COMPANY

# FINANCIAL SECTION

**MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING**
**Alabama Power Company 2017 Annual Report**

The management of Alabama Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2017 .

/s/ Mark A. Crosswhite
Mark A. Crosswhite
Chairman, President, and Chief Executive Officer

/s/ Philip C. Raymond
Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer

February 20, 2018

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the stockholders and the Board of Directors of Alabama Power Company

**Opinion on the Financial Statements**

We have audited the accompanying balance sheets and statements of capitalization of Alabama Power Company (the Company) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2017 and 2016 , the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2017 , and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements (pages II-186 to II-231 ) present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016 , and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017 , in conformity with accounting principles generally accepted in the United States of America.

**Basis for Opinion**

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP
Birmingham, Alabama
February 20, 2018

We have served as the Company's auditor since 2002.

# DEFINITIONS

| Term | Meaning |
|---|---|
| AFUDC | Allowance for funds used during construction |
| ARO | Asset retirement obligation |
| ASC | Accounting Standards Codification |
| ASU | Accounting Standards Update |
| CCR | Coal combustion residuals |
| Clean Air Act | Clean Air Act Amendments of 1990 |
| $CO_2$ | Carbon dioxide |
| DOE | U.S. Department of Energy |
| EPA | U.S. Environmental Protection Agency |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| GAAP | U.S. generally accepted accounting principles |
| Georgia Power | Georgia Power Company |
| Gulf Power | Gulf Power Company |
| IRS | Internal Revenue Service |
| ITC | Investment tax credit |
| KWH | Kilowatt-hour |
| LIBOR | London Interbank Offered Rate |
| Mississippi Power | Mississippi Power Company |
| mmBtu | Million British thermal units |
| Moody's | Moody's Investors Service, Inc. |
| MW | Megawatt |
| NDR | Natural Disaster Reserve |
| $NO_X$ | Nitrogen oxide |
| NRC | U.S. Nuclear Regulatory Commission |
| OCI | Other comprehensive income |
| power pool | The operating arrangement whereby the integrated generating resources of the traditional electric operating companies and Southern Power (excluding subsidiaries) are subject to joint commitment and dispatch in order to serve their combined load obligations |
| PPA | Power purchase agreement |
| PSC | Public Service Commission |
| Rate CNP | Rate Certificated New Plant |
| Rate CNP Compliance | Rate Certificated New Plant Compliance |
| Rate CNP PPA | Rate Certificated New Plant Power Purchase Agreement |
| Rate ECR | Rate Energy Cost Recovery |
| Rate NDR | Rate Natural Disaster Reserve |
| Rate RSE | Rate Stabilization and Equalization plan |
| ROE | Return on equity |
| S&P | S&P Global Ratings, a division of S&P Global Inc. |
| SCS | Southern Company Services, Inc. (the Southern Company system service company) |
| SEC | U.S. Securities and Exchange Commission |
| SEGCO | Southern Electric Generating Company |
| $SO_2$ | Sulfur dioxide |
| Southern Company | The Southern Company |
| Southern Company Gas | Southern Company Gas and its subsidiaries |

**DEFINITIONS**
(continued)

| Term | Meaning |
| --- | --- |
| Southern Company system | Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), SEGCO, Southern Nuclear, SCS, Southern Linc, PowerSecure, Inc. (as of May 9, 2016), and other subsidiaries |
| Southern Linc | Southern Communications Services, Inc. |
| Southern Nuclear | Southern Nuclear Operating Company, Inc. |
| Southern Power | Southern Power Company and its subsidiaries |
| Tax Reform Legislation | The Tax Cuts and Jobs Act, which was signed into law on December 22, 2017 and became effective on January 1, 2018 |
| traditional electric operating companies | Alabama Power Company, Georgia Power, Gulf Power, and Mississippi Power |

**MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS**
**Alabama Power Company 2017 Annual Report**

## OVERVIEW

### Business Activities

Alabama Power Company (the Company) operates as a vertically integrated utility providing electric service to retail and wholesale customers within its traditional service territory located in the State of Alabama in addition to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of providing electric service. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales and customers, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, stringent environmental standards, reliability, fuel, capital expenditures, and restoration following major storms. The Company has various regulatory mechanisms that operate to address cost recovery. Effectively operating pursuant to these regulatory mechanisms and appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

The Company continues to focus on several key performance indicators including, but not limited to, customer satisfaction, plant availability, system reliability, and net income after dividends on preferred and preference stock. The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys to evaluate the Company's results and generally targets the top quartile of these surveys in measuring performance.

See RESULTS OF OPERATIONS herein for information on the Company's financial performance.

### Earnings

The Company's 2017 net income after dividends on preferred and preference stock was $848 million, representing a $26 million, or 3.2%, increase over the previous year. The increase was primarily due to an increase in rates under Rate RSE effective in January 2017 and the impact of a Rate RSE refund recorded in 2016. These increases to income were partially offset by a decrease in retail revenues associated with milder weather, lower customer usage, and an increase in non-fuel operations and maintenance expenses in 2017 as compared to 2016. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Rate RSE" herein for additional information.

The Company's 2016 net income after dividends on preferred and preference stock was $822 million , representing a $37 million, or 4.7%, increase over the previous year. The increase was due primarily to an increase in retail revenues under Rate CNP Compliance, an increase in weather-related revenues, and a decrease in operations and maintenance expenses not related to fuel or Rate CNP Compliance. These increases to income were partially offset by an accrual for a Rate RSE refund, a decrease in AFUDC equity, and an increase in depreciation.

**MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)**
**Alabama Power Company 2017 Annual Report**

**RESULTS OF OPERATIONS**

A condensed income statement for the Company follows:

| | Amount | Increase (Decrease) from Prior Year | |
|---|---|---|---|
| | **2017** | **2017** | 2016 |
| | | (in millions) | |
| Operating revenues | **$ 6,039** | **$ 150** | $ 121 |
| Fuel | **1,225** | **(72)** | (45) |
| Purchased power | **328** | **(6)** | (17) |
| Other operations and maintenance | **1,652** | **142** | 9 |
| Depreciation and amortization | **736** | **33** | 60 |
| Taxes other than income taxes | **384** | **4** | 12 |
| Total operating expenses | **4,325** | **101** | 19 |
| Operating income | **1,714** | **49** | 102 |
| Allowance for equity funds used during construction | **39** | **11** | (32) |
| Interest expense, net of amounts capitalized | **305** | **3** | 28 |
| Other income (expense), net | **(14)** | **7** | 11 |
| Income taxes | **568** | **37** | 25 |
| Net income | **866** | **27** | 28 |
| Dividends on preferred and preference stock | **18** | **1** | (9) |
| Net income after dividends on preferred and preference stock | **$ 848** | **$ 26** | $ 37 |

***Operating Revenues***

Operating revenues for 2017 were $6.0 billion , reflecting a $150 million increase from 2016. Details of operating revenues were as follows:

| | Amount | |
|---|---|---|
| | **2017** | 2016 |
| | (in millions) | |
| Retail — prior year | **$ 5,322** | $ 5,234 |
| Estimated change resulting from — | | |
| Rates and pricing | **362** | 147 |
| Sales decline | **(44)** | (20) |
| Weather | **(89)** | 31 |
| Fuel and other cost recovery | **(93)** | (70) |
| Retail — current year | **5,458** | 5,322 |
| Wholesale revenues — | | |
| Non-affiliates | **276** | 283 |
| Affiliates | **97** | 69 |
| Total wholesale revenues | **373** | 352 |
| Other operating revenues | **208** | 215 |
| Total operating revenues | **$ 6,039** | $ 5,889 |
| Percent change | **2.6%** | 2.1% |

Retail revenues in 2017 were $5.5 billion . These revenues increased $ 136 million , or 2.6% , in 2017 and $88 million, or 1.7%, in 2016, each as compared to the prior year. The increase in 2017 was primarily due to an increase in rates under Rate RSE effective in January 2017, partially offset by a decrease in fuel revenues and milder weather in the first and third quarters 2017 as compared to the corresponding periods in 2016. The increase in 2016 was due to an increase in revenues under Rate CNP Compliance as a result of increased net investments, partially offset by a decrease in fuel revenues and an accrual for a Rate RSE refund. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate RSE" for additional information. See "Energy Sales" herein for a discussion of changes in the volume of energy sold, including changes related to sales decline and weather.

Fuel rates billed to customers are designed to fully recover fluctuating fuel and purchased power costs over a period of time. Fuel revenues generally have no effect on net income because they represent the recording of revenues to offset fuel and purchased power expenses. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate ECR" for additional information.

Wholesale revenues from power sales to non-affiliated utilities were as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| Capacity and other | **$ 154** | $ 154 | $ 140 |
| Energy | **122** | 129 | 101 |
| Total non-affiliated | **$ 276** | $ 283 | $ 241 |

Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not affect net income. Short-term opportunity energy sales are also included in wholesale energy sales to non-affiliates. These opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost to produce the energy.

In 2017, wholesale revenues from sales to non-affiliates decreased $ 7 million , or 2.5% , as compared to the prior year. In 2016, wholesale revenues from sales to non-affiliates increased $42 million, or 17.4%, as compared to the prior year primarily due to a $28 million increase in revenues from energy sales and a $14 million increase in capacity revenues. In 2016, KWH sales increased 33.3% primarily due to a new contract that became effective in the first quarter 2016 partially offset by a 12.1% decrease in the price of energy due to lower natural gas prices.

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost and energy purchases are generally offset by energy revenues through the Company's energy cost recovery clause.

In 2017, wholesale revenues from sales to affiliates increased $28 million , or 40.6% , as compared to the prior year. In 2017, KWH sales increased 31.1% as a result of supporting Southern Company system transmission reliability and a 6.9% increase in the price of energy primarily due to higher natural gas prices. In 2016, wholesale revenues from sales to affiliates decreased $15 million, or 17.9%, as compared to the prior year. In 2016, KWH sales decreased 15.7% as a result of lower-cost generation available in the Southern Company system and a 2.6% decrease in the price of energy primarily due to lower natural gas prices.

*Energy Sales*

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2017 and the percent change from the prior year were as follows:

| | Total KWHs | Total KWH Percent Change | | Weather-Adjusted Percent Change | |
|---|---|---|---|---|---|
| | **2017** | **2017** | 2016 | **2017** | 2016 |
| | *(in billions)* | | | | |
| Residential | **17.2** | **(6.1)%** | 1.4% | **(1.2)%** | (0.5)% |
| Commercial | **13.6** | **(3.4)** | (0.1) | **(1.3)** | (0.5) |
| Industrial | **22.7** | **1.7** | (4.6) | **1.7** | (4.6) |
| Other | **0.2** | **(5.0)** | 3.8 | **(5.0)** | 3.8 |
| Total retail | **53.7** | **(2.3)** | (1.5) | **(0.1)%** | (2.2)% |
| Wholesale | | | | | |
| Non-affiliates | **5.5** | **(6.5)** | 37.1 | | |
| Affiliates | **4.2** | **31.1** | (15.7) | | |
| Total wholesale | **9.7** | **6.6** | 12.5 | | |
| Total energy sales | **63.4** | **(1.0)%** | 0.3% | | |

Changes in retail energy sales are generally the result of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales in 2017 were 2.3% lower than in 2016. Residential sales and commercial sales decreased 6.1% and 3.4% in 2017, respectively, primarily due to milder weather in the first and third quarters 2017 as compared to the corresponding periods in 2016. Weather-adjusted residential sales were 1.2% lower in 2017 primarily due to lower customer usage resulting from an increase in penetration of energy-efficient residential appliances, partially offset by customer growth. Weather-adjusted commercial sales were 1.3% lower in 2017 primarily due to lower customer usage resulting from customer initiatives in energy savings and an ongoing migration to the electronic commerce business model, partially offset by customer growth. Industrial sales increased 1.7% in 2017 as compared to 2016 as a result of an increase in demand resulting from changes in production levels primarily in the primary metals, chemicals, and mining sectors offset by the pipelines and paper sectors.

Retail energy sales in 2016 were 1.5% lower than in 2015. Residential sales increased 1.4% primarily due to warmer weather in the third quarter 2016 as compared to the corresponding period in 2015. Commercial sales remained flat in 2016. Weather-adjusted residential sales were flat in 2016 due to lower customer usage primarily resulting from an increase in efficiency improvements in residential appliances and lighting, partially offset by customer growth. Industrial sales decreased 4.6% in 2016 compared to 2015 as a result of a decrease in demand resulting from changes in production levels primarily in the primary metals, chemical, pipelines, paper, and stone, clay, and glass sectors. A strong dollar, low oil prices, and weak global growth conditions constrained growth in the industrial sector in 2016.

See "Operating Revenues" above for a discussion of significant changes in wholesale revenues from sales to non-affiliates and wholesale revenues from sales to affiliated companies as related to changes in price and KWH sales.

***Fuel and Purchased Power Expenses***

Fuel costs constitute one of the largest expenses for the Company. The mix of fuel sources for generation of electricity is determined primarily by the unit cost of fuel consumed, demand, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

**MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)**
**Alabama Power Company 2017 Annual Report**

Details of the Company's generation and purchased power were as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| Total generation *(in billions of KWHs)* | **60.3** | 60.2 | 60.9 |
| Total purchased power *(in billions of KWHs)* | **6.4** | 7.1 | 6.3 |
| Sources of generation *(percent)* — | | | |
| Coal | **50** | 53 | 54 |
| Nuclear | **24** | 23 | 24 |
| Gas | **20** | 19 | 16 |
| Hydro | **6** | 5 | 6 |
| Cost of fuel, generated *(in cents per net KWH)* — | | | |
| Coal | **2.60** | 2.75 | 2.83 |
| Nuclear | **0.75** | 0.78 | 0.81 |
| Gas | **2.72** | 2.67 | 2.94 |
| Average cost of fuel, generated *(in cents per net KWH)* [(a)] | **2.14** | 2.26 | 2.34 |
| Average cost of purchased power *(in cents per net KWH)* [(b)] | **5.29** | 4.80 | 5.66 |

(a) KWHs generated by hydro are excluded from the average cost of fuel, generated.

(b) Average cost of purchased power includes fuel, energy, and transmission purchased by the Company for tolling agreements where power is generated by the provider.

Fuel and purchased power expenses were $1.55 billion in 2017, a decrease of $78 million , or 4.8% , compared to 2016. The decrease was primarily due to a $67 million net decrease related to the volume of KWHs generated and purchased and a $42 million decrease in the average cost of fuel, partially offset by a $31 million increase in the average cost of purchased power.

Fuel and purchased power expenses were $1.63 billion in 2016, a decrease of $62 million, or 3.7%, compared to 2015. The decrease was primarily due to a $61 million decrease in the average cost of purchased power, and a $59 million decrease in the average cost of fuel, partially offset by a $49 million increase related to the volume of KWHs purchased.

Fuel and purchased power energy transactions do not have a significant impact on earnings, since energy expenses are generally offset by energy revenues through the Company's energy cost recovery clause. The Company, along with the Alabama PSC, continuously monitors the under/over recovered balance to determine whether adjustments to billing rates are required. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate ECR" for additional information.

Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation.

*Fuel*

Fuel expenses were $1.2 billion in 2017, a decrease of $72 million , or 5.6% , compared to 2016. The decrease was primarily due to a 12.2% increase in the volume of KWHs generated by hydro, a 5.8% decrease in the volume of KWHs generated by coal, and a 5.5% and 3.9% decrease in the average cost of KWHs generated by coal and nuclear fuel, respectively. These decreases were partially offset by an 8.1% increase in the volume of KWHs generated by nuclear fuel and a 4.0% increase in the volume of KWHs generated by natural gas. Fuel expenses were $1.3 billion in 2016, a decrease of $45 million, or 3.4%, compared to 2015. The decrease was primarily due to a 9.2% decrease in the average cost of KWHs generated by natural gas, which excludes tolling agreements, a 4.2% and 3.9% decrease in the volume of KWHs generated by nuclear fuel and coal, respectively, and a 3.7% decrease in the average cost of KWHs generated by nuclear fuel, partially offset by a 17.4% increase in the volume of KWHs generated by natural gas.

*Purchased Power – Affiliates*

Purchased power expense from affiliates was $158 million in 2017, a decrease of $10 million , or 6.0% , compared to 2016. This decrease was primarily due to a 17.2% decrease in the amount of energy purchased due to milder weather partially offset by a 13.9% increase in the average cost per KWH purchased due to higher natural gas prices. Purchased power expense from affiliates was $168 million in 2016, a decrease of $12 million, or 6.7%, compared to 2015. This decrease was primarily due to a

20.7% decrease in the average cost per KWH purchased due to lower natural gas prices, partially offset by a 17.5% increase in the amount of energy purchased due to the availability of lower-cost generation compared to the Company's owned generation.

Energy purchases from affiliates will vary depending on demand for energy and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC or other contractual agreements, as approved by the FERC.

***Other Operations and Maintenance Expenses***

In 2017, other operations and maintenance expenses increased $142 million , or 9.4% , as compared to the prior year. Distribution and transmission expenses increased $58 million primarily due to vegetation management expenses. Generation costs increased $38 million primarily due to outage costs. Employee benefit costs, including pension costs, increased $22 million.

In 2016, other operations and maintenance expenses increased $9 million, or 0.6%, as compared to the prior year. Steam production costs increased $28 million primarily due to the timing of generation operating expenses. Transmission and distribution expenses increased $10 million and $7 million, respectively, primarily due to additional vegetation management and other maintenance expenses. These increases were partially offset by a decrease of $32 million in employee benefit costs, including pension costs. The increases in operations and maintenance expenses were primarily Rate CNP compliance-related costs and therefore had no significant impact to net income. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Rate CNP Compliance" herein for additional information.

See Note 2 to the financial statements under "Pension Plans" for additional information.

***Depreciation and Amortization***

Depreciation and amortization increased $33 million , or 4.7% , in 2017 as compared to the prior year primarily due to additional plant in service and an increase in generation-related depreciation rates, effective January 1, 2017, associated with compliance-related steam projects and ARO recovery, partially offset by a decrease in distribution-related depreciation rates. See Note 1 to the financial statements under "Depreciation and Amortization" for additional information. Depreciation and amortization increased $60 million, or 9.3%, in 2016 as compared to the prior year primarily due to compliance-related steam projects placed in service.

***Taxes Other Than Income Taxes***

Taxes other than income taxes increased $4 million , or 1.1% , in 2017 as compared to the prior year. In 2016, taxes other than income taxes increased $12 million, or 3.3% in 2016 as compared to the prior year. The increase was primarily due to increases in state and municipal utility license tax bases primarily due to an increase in retail revenues. In addition, ad valorem taxes increased primarily due to an increase in assessed value of property.

***Allowance for Equity Funds Used During Construction***

AFUDC equity increased $11 million , or 39.3% , in 2017 as compared to the prior year. The increase was primarily associated with steam, transmission, and nuclear construction projects. AFUDC equity decreased $32 million, or 53.3%, in 2016 as compared to the prior year. The decrease was primarily associated with steam generation capital projects being placed in service. See Note 1 to financial statements under "Allowance for Funds Used During Construction" for additional information.

***Interest Expense, Net of Amounts Capitalized***

Interest expense, net of amounts capitalized increased $3 million , or 1.0% , in 2017 as compared to the prior year. Interest expense, net of amounts capitalized increased $28 million, or 10.2%, in 2016 as compared to the prior year primarily due to an increase in debt outstanding and a reduction in the amounts capitalized. See FUTURE EARNINGS POTENTIAL – "Financing Activities" herein for additional information.

***Other Income (Expense), Net***

Other income (expense), net increased $7 million , or 33.3% , in 2017 as compared to the prior year primarily due to increases in unregulated lighting services. Other income (expense), net increased $11 million, or 34.4%, in 2016 as compared to the prior year primarily due to a decrease in donations, partially offset by a decrease in sales of non-utility property.

***Income Taxes***

Income taxes increased $37 million , or 7.0% , in 2017 as compared to the prior year primarily due to higher pre-tax earnings, an increase in prior year tax return actualization, and an increase in income tax reserves, partially offset by an increase in state income tax credits. The impact to income taxes as a result of Tax Reform Legislation was not material due to the application of regulatory accounting. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation " herein and Note 5 to the financial statements for additional information. Income taxes increased $25 million, or 4.9%, in 2016 as compared to the prior year primarily due to higher pre-tax earnings.

***Dividends on Preferred and Preference Stock***

Dividends on preferred and preference stock increased $1 million , or 5.9% , in 2017 as compared to the prior year. Dividends on preferred and preference stock decreased $9 million, or 34.6%, in 2016 as compared to the prior year. The decrease was primarily due to the redemption in May 2015 of certain series of preferred and preference stock. See Note 6 to the financial statements under "Redeemable Preferred and Preference Stock" for additional information.

**Effects of Inflation**

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate RSE" for additional information.

**FUTURE EARNINGS POTENTIAL**

**General**

The Company operates as a vertically integrated utility providing electric service to retail and wholesale customers within its traditional service territory located in the State of Alabama and to wholesale customers in the Southeast. Prices for electric service provided by the Company to retail customers are set by the Alabama PSC under cost-based regulatory principles. Prices for wholesale electric service, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's primary business of providing electric service. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs and limited projected demand growth over the next several years. Future earnings will be impacted by customer growth. Earnings will also depend upon maintaining and growing sales, considering, among other things, the adoption and/or penetration rates of increasingly energy-efficient technologies and increasing volumes of electronic commerce transactions, both of which could contribute to a net reduction in customer usage. Earnings are subject to a variety of other factors. These factors include weather, competition, new energy contracts with other utilities, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territory. Demand for electricity is primarily driven by the pace of economic growth that may be affected by changes in regional and global economic conditions, which may impact future earnings.

On December 22, 2017, Tax Reform Legislation was signed into law and became effective on January 1, 2018, which, among other things, reduces the federal corporate income tax rate to 21% and changes rates of depreciation and the business interest deduction. See " Income Tax Matters – Federal Tax Reform Legislation " and FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein and Notes 3 and 5 to the financial statements under "Retail Regulatory Matters – Rate RSE" and "Current and Deferred Income Taxes," respectively, for additional information.

**Environmental Matters**

The Company's operations are regulated by state and federal environmental agencies through a variety of laws and regulations governing air, water, land, and protection of other natural resources. The Company maintains a comprehensive environmental compliance strategy to assess upcoming requirements and compliance costs associated with these environmental laws and regulations. The costs, including capital expenditures and operations and maintenance costs, required to comply with environmental laws and regulations may impact future unit retirement and replacement decisions, results of operations, cash flows, and financial condition. Compliance costs may result from the installation of additional environmental controls, closure and monitoring of CCR facilities, unit retirements, and adding or changing fuel sources for certain existing units, as well as related upgrades to the transmission system. A major portion of these compliance costs are expected to be recovered through existing ratemaking provisions. The ultimate impact of the environmental laws and regulations discussed below will depend on various factors, such as state adoption and implementation of requirements, the availability and cost of any deployed control technology, and the outcome of pending and/or future legal challenges.

New or revised environmental laws and regulations could affect many areas of the Company's operations. The impact of any such changes cannot be determined at this time. Environmental compliance costs could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis . Environmental compliance costs are recovered through Rate CNP Compliance. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate CNP Compliance" for additional information . Further, increased costs that are recovered through regulated rates could contribute to reduced demand for electricity , which could negatively affect results of operations, cash flows, and financial condition. Additionally, many commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity .

Through 2017 , the Company has invested approximately $4.7 billion in environmental capital retrofit projects to comply with environmental requirements, with annual totals of approximately $491 million, $260 million, and $349 million for 2017 , 2016 , and 2015 , respectively. Although the timing, requirements, and estimated costs could change as environmental laws and regulations are adopted or modified, as compliance plans are revised or updated, and as legal challenges to rules are initiated or completed, the Company's current compliance strategy estimates capital expenditures of $1.4 billion from 2018 through 2022 , with annual totals of approximately $581 million in 2018 , $110 million in 2019 , $163 million in 2020 , $258 million in 2021 , and $268 million in 2022 . These estimates do not include any potential compliance costs associated with the regulation of $CO_2$ emissions from fossil fuel-fired electric generating units. See "Global Climate Issues" herein for additional information. The Company also anticipates expenditures associated with ash pond closure and ground water monitoring under the Disposal of Coal Combustion Residuals from Electric Utilities rule (CCR Rule), which are reflected in the Company's ARO liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

***Environmental Laws and Regulations***

*Air Quality*

The EPA has set National Ambient Air Quality Standards (NAAQS) for six air pollutants (carbon monoxide, lead, nitrogen dioxide, ozone, particulate matter, and $SO_2$ ), which it reviews and revises periodically. Revisions to these standards can require additional emission controls, improvements in control efficiency, or fuel changes which can result in increased compliance and operational costs. NAAQS requirements can also adversely affect the siting of new facilities. In 2015, the EPA published a more stringent eight-hour ozone NAAQS. The EPA plans to complete designations for this rule by no later than April 30, 2018 . No areas within the Company's service territory have been or are anticipated to be designated nonattainment under the 2015 ozone NAAQS. In 2010, the EPA revised the NAAQS for $SO_2$ , establishing a new one-hour standard, and is completing designations in multiple phases. The EPA has issued several rounds of area designations and no areas in the vicinity of Company -owned $SO_2$ sources have been designated nonattainment under the 2010 one-hour $SO_2$ NAAQS. However, final eight-hour ozone and $SO_2$ one-hour designations for certain areas are still pending and, if other areas are designated as nonattainment in the future, increased compliance costs could result.

In 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) and its $NO_X$ annual, $NO_X$ seasonal, and $SO_2$ annual programs. CSAPR is an emissions trading program that addresses the impacts of the interstate transport of $SO_2$ and $NO_X$ emissions from fossil fuel-fired power plants located in upwind states in the eastern half of the U.S. on air quality in downwind states. The Company has fossil fuel-fired generation subject to these requirements. In October 2016, the EPA published a final rule that revised the CSAPR seasonal $NO_X$ program, establishing more stringent $NO_X$ emissions budgets in Alabama . Increases in either future fossil fuel-fired generation or the cost of CSAPR allowances could have a negative financial impact on results of operations for the Company .

The EPA finalized regional haze regulations in 2005 and 2017. These regulations require states, tribal governments, and various federal agencies to develop and implement plans to reduce pollutants that impair visibility and demonstrate reasonable progress toward the goal of restoring natural visibility conditions in certain areas, including national parks and wilderness areas. States must submit a revised state implementation plan (SIP) to the EPA by July 31, 2021, demonstrating reasonable progress towards achieving visibility improvement goals. State implementation of reasonable progress could require further reductions in $SO_2$ or $NO_X$ emissions, which could result in increased compliance costs.

In 2015, the EPA published a final rule requiring certain states (including Alabama ) to revise or remove the provisions of their SIPs regulating excess emissions at industrial facilities, including electric generating facilities, during periods of startup, shut-down, or malfunction (SSM). The state excess emission rules provide necessary operational flexibility to affected units during periods of SSM and, if removed, could affect unit availability and result in increased operations and maintenance costs for the Company.

*Water Quality*

In 2014, the EPA finalized requirements under Section 316(b) of the Clean Water Act (CWA) to regulate cooling water intake structures at existing power plants and manufacturing facilities in order to minimize their effects on fish and other aquatic life. The regulation requires plant-specific studies to determine applicable measures to protect organisms that either get caught on the intake screens (impingement) or are drawn into the cooling system (entrainment). The ultimate impact of this rule will depend on the outcome of these plant-specific studies and any additional protective measures required to be incorporated into each plant's National Pollutant Discharge Elimination System (NPDES) permit based on site-specific factors.

In 2015, the EPA finalized the steam electric effluent limitations guidelines (ELG) rule that set national standards for wastewater discharges from steam electric generating units. The rule prohibits effluent discharges of certain wastestreams and imposes stringent arsenic, mercury, selenium, and nitrate/nitrite limits on scrubber wastewater discharges. The revised technology-based limits and compliance dates may require extensive modifications to existing ash and wastewater management systems or the installation and operation of new ash and wastewater management systems. Compliance with the ELG rule is expected to require capital expenditures and increased operational costs primarily affecting the Company's coal-fired electric generation. Compliance applicability dates range from November 1, 2018 to December 31, 2023 with state environmental agencies incorporating specific applicability dates in the NPDES permitting process based on information provided for each waste stream. The EPA has committed to a new rulemaking that could potentially revise the limitations and applicability dates of the ELG rule. The EPA expects to finalize this rulemaking in 2020. The Company continues to monitor the ELG rule and anticipates that approximately 1,000 MWs of the Company's generation will not be available after the compliance date. The ultimate impact of this rule will depend on any new rule-making that revises the limitation and applicable dates. The Company does not anticipate that the unavailability of any units as a result of the ELG rule will have a material impact on the Company's operations or financial condition.

In 2015, the EPA and the U.S. Army Corps of Engineers (Corps) jointly published a final rule that revised the regulatory definition of waters of the United States (WOTUS) for all CWA programs. The rule significantly expanded the scope of federal jurisdiction over waterbodies (such as rivers, streams, and canals), which could impact new generation projects and permitting and reporting requirements associated with the installation, expansion, and maintenance of transmission and distribution projects. On July 27, 2017, the EPA and the Corps proposed to rescind the 2015 WOTUS rule. The WOTUS rule has been stayed by the U.S. Court of Appeals for the Sixth Circuit since late 2015, but on January 22, 2018, the U.S. Supreme Court determined that federal district courts have jurisdiction over the pending challenges to the rule. On February 6, 2018, the EPA and the Corps published a final rule delaying implementation of the 2015 WOTUS rule to 2020.

*Coal Combustion Residuals*

In 2015, the EPA finalized non-hazardous solid waste regulations for the disposal of CCR, including coal ash and gypsum, in landfills and surface impoundments (CCR units) at active generating power plants. The CCR Rule requires CCR units to be evaluated against a set of performance criteria and potentially closed if minimum criteria are not met. Closure of existing CCR units could require installation of equipment and infrastructure to manage CCR in accordance with the rule. The EPA has announced plans to reconsider certain portions of the CCR Rule by no later than December 2019, which could result in changes to deadlines and corrective action requirements.

The EPA's reconsideration of the CCR Rule is due in part to a legislative development that impacts the potential oversight role of state agencies. Under the Water Infrastructure Improvements for the Nation Act, which became law in 2016, states are allowed to establish permit programs for implementing the CCR Rule.

Based on cost estimates for closure in place and monitoring of ash ponds pursuant to the CCR Rule, the Company recorded AROs for each CCR unit in 2015. As further analysis is performed and closure details are developed, the Company will continue to periodically update these cost estimates as necessary. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information regarding the Company's AROs as of December 31, 2017 .

***Global Climate Issues***

In 2015, the EPA published final rules limiting $CO_2$ emissions from new, modified, and reconstructed fossil fuel-fired electric generating units and guidelines for states to develop plans to meet EPA-mandated $CO_2$ emission performance standards for existing units (known as the Clean Power Plan or CPP). In February 2016, the U.S. Supreme Court granted a stay of the CPP, which will remain in effect through the resolution of litigation in the U.S. Court of Appeals for the District of Columbia challenging the legality of the CPP and any review by the U.S. Supreme Court. On March 28, 2017, the U.S. President signed an executive order directing agencies to review actions that potentially burden the development or use of domestically produced energy resources, including review of the CPP and other $CO_2$ emissions rules. On October 10, 2017, the EPA published a proposed rule to repeal the CPP and, on December 28, 2017, published an advanced notice of proposed rulemaking regarding a CPP replacement rule.

In 2015, parties to the United Nations Framework Convention on Climate Change, including the United States, adopted the Paris Agreement, which established a non-binding universal framework for addressing greenhouse gas (GHG) emissions based on nationally determined contributions. On June 1, 2017, the U.S. President announced that the United States would withdraw from the Paris Agreement and begin renegotiating its terms. The ultimate impact of this agreement or any renegotiated agreement depends on its implementation by participating countries.

The EPA's GHG reporting rule requires annual reporting of GHG emissions expressed in terms of metric tons of $CO_2$ equivalent emissions for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2016 GHG emissions were approximately 38 million metric tons of $CO_2$ equivalent. The preliminary estimate of the Company's 2017 GHG emissions on the same basis is approximately 37 million metric tons of $CO_2$ equivalent.

**FERC Matters**

The Company has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies (including the Company) and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In 2015, the FERC issued an order finding that the traditional electric operating companies' (including the Company's) and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional electric operating companies (including the Company) and Southern Power filed a request for rehearing and filed their response with the FERC in 2015.

In December 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. On May 17, 2017, the FERC accepted the traditional electric operating companies' (including the Company's) and Southern Power's compliance filing accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

On October 25, 2017, the FERC issued an order in response to the traditional electric operating companies' (including the Company's) and Southern Power's June 29, 2017 triennial updated market power analysis. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show cause within 60 days why market-based rate authority should not be revoked in certain areas adjacent to the area presently under mitigation in accordance with the February 2, 2017 order or to provide a mitigation plan to further address market power concerns. On November 10, 2017, the traditional electric operating companies (including the Company) and Southern Power responded to the FERC and proposed to resolve matters by applying the alternative mitigation authorized by the February 2, 2017 order to the adjacent areas made the subject of the October 25, 2017 order.

The ultimate outcome of these matters cannot be determined at this time.

**Retail Regulatory Matters**

The Company 's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the Alabama PSC. The Company currently recovers its costs from the regulated retail business primarily through Rate RSE, Rate CNP, Rate ECR, and Rate NDR. In addition, the Alabama PSC issues accounting orders to address current events impacting the Company. See Note 1 to the financial statements and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information regarding the Company's rate mechanisms and accounting orders.

***Rate RSE***

The Alabama PSC has adopted Rate RSE that provides for periodic annual adjustments based upon the Company's projected weighted cost of equity (WCE) compared to an allowable range. Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate RSE adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. If the Company's actual retail return is above the allowed WCE range, the excess will be refunded to customers unless otherwise directed by the Alabama PSC; however, there is no provision for additional customer billings should the actual retail return fall below the WCE range.

At December 31, 2016, the Company's retail return exceeded the allowed WCE range which resulted in the Company establishing a $73 million Rate RSE refund liability. In accordance with an Alabama PSC order issued on February 14, 2017, the Company applied the full amount of the refund to reduce the under recovered balance of Rate CNP PPA as discussed further below.

Effective in January 2017, Rate RSE increased 4.48%, or $245 million annually. At December 31, 2017, the Company's actual retail return was within the allowed WCE range. On December 1, 2017, the Company made its required annual Rate RSE submission to the Alabama PSC of projected data for calendar year 2018. Projected earnings were within the specified range; therefore, retail rates under Rate RSE remained unchanged for 2018.

In conjunction with Rate RSE, the Company has an established retail tariff that provides for an adjustment to customer billings to recognize the impact of a change in the statutory income tax rate. As a result of Tax Reform Legislation, the application of this tariff would reduce annual retail revenue by approximately $250 million over the remainder of 2018. The ultimate outcome of this matter cannot be determined at this time.

***Rate CNP PPA***

The Company's retail rates, approved by the Alabama PSC, provide for adjustments under Rate CNP to recognize the placing of new generating facilities into retail service. The Company may also recover retail costs associated with certificated PPAs under Rate CNP PPA. On March 7, 2017, the Alabama PSC issued a consent order that the Company leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2017 through March 31, 2018. No adjustment to Rate CNP PPA is expected in 2018.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, the Company eliminated the under recovered balance in Rate CNP PPA at December 31, 2016, which totaled approximately $142 million. As discussed herein under "Rate RSE," the Company utilized the full amount of its $73 million Rate RSE refund liability to reduce the amount of the Rate CNP PPA under recovery and reclassified the remaining $69 million to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of the Company's next depreciation study, which is expected to occur within the next two to four years. The Company's current depreciation study became effective January 1, 2017.

***Rate CNP Compliance***

Rate CNP Compliance allows for the recovery of the Company's retail costs associated with laws, regulations, and other such mandates directed at the utility industry involving the environment, security, reliability, safety, sustainability, or similar considerations impacting the Company's facilities or operations. Rate CNP Compliance is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Compliance costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. Revenues for Rate CNP Compliance, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. Changes in Rate CNP Compliance-related operations and maintenance expenses and depreciation generally will have no effect on net income.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, the Company reclassified $36 million of its under recovered balance in Rate CNP Compliance to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of the Company's next depreciation study, which is expected to occur within the next two to four years. The Company's current depreciation study became effective January 1, 2017.

On December 5, 2017, the Alabama PSC issued a consent order that the Company leave in effect for 2018 the factors associated with the Company's compliance costs for the year 2017, with any under-collected amount for prior years deemed recovered before any current year amounts. Any under recovered amounts associated with 2018 will be reflected in the 2019 filing.

***Rate ECR***

The Company has established energy cost recovery rates under the Company's Rate ECR as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. The Company, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on the Company's net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per KWH.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, the Company reclassified $36 million of its under recovered balance in Rate ECR to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of the Company's next depreciation study, which is expected to occur within the next two to four years. The Company's current depreciation study became effective January 1, 2017.

On December 5, 2017, the Alabama PSC issued a consent order that the Company leave in effect for 2018 the energy cost recovery rates which began in 2017. Therefore, the Rate ECR factor as of January 1, 2018 remained at 2.015 cents per KWH. The rate will return to 5.910 cents per KWH in 2019, absent a further order from the Alabama PSC.

***Rate NDR***

Based on an order from the Alabama PSC, the Company maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate NDR charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. When the reserve balance falls below $50 million , a reserve establishment charge will be activated (and the on-going reserve maintenance charge concurrently suspended) until the reserve balance reaches $75 million . The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24 -month period.

In December 2017, the reserve maintenance charge was suspended and the reserve establishment charge was activated as a result of the NDR balance falling below $50 million . The Company expects to collect approximately $16 million annually until the reserve balance is restored to $75 million. The NDR balance at December 31, 2017 was $38 million .

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

***Environmental Accounting Order***

Based on an order from the Alabama PSC, the Company is allowed to establish a regulatory asset to record the unrecovered investment costs, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure associated with future unit retirements caused by environmental regulations. The regulatory asset will be amortized and recovered over the affected unit's remaining useful life, as established prior to the decision regarding early retirement through Rate CNP Compliance. See "Environmental Matters – Environmental Laws and Regulations" herein for additional information regarding environmental regulations.

**Income Tax Matters**

***Federal Tax Reform Legislation***

On December 22, 2017, the Tax Reform Legislation was signed into law and became effective on January 1, 2018. The Tax Reform Legislation, among other things, reduces the federal corporate income tax rate to 21%, retains normalization provisions for public utility property and existing renewable energy incentives, and repeals the corporate alternative minimum tax.

Regulated utility businesses can continue deducting all business interest expense and are not eligible for bonus depreciation on capital assets acquired and placed in service after September 27, 2017. Projects with binding contracts before September 28, 2017 and placed in service after September 27, 2017 remain eligible for bonus depreciation under the Protecting Americans from Tax Hikes (PATH) Act.

In addition, under the Tax Reform Legislation, net operating losses (NOL) generated after December 31, 2017 can no longer be carried back to previous tax years but can be carried forward indefinitely, with utilization limited to 80% of taxable income in the subsequent tax year. The projected reduction of Southern Company's consolidated income tax liability resulting from the tax rate reduction also delays the expected utilization of existing tax credit carryforwards.

For the year ended December 31, 2017, implementation of the Tax Reform Legislation resulted in an estimated net tax expense of $3 million, a $271 million decrease in regulatory assets, and a $2.0 billion increase in regulatory liabilities, primarily due to the impact of the reduction of the corporate income tax rate on deferred tax assets and liabilities.

The Tax Reform Legislation is subject to further interpretation and guidance from the IRS, as well as each respective state's adoption. In addition, the regulatory treatment of certain impacts of the Tax Reform Legislation is subject to the discretion of the FERC and the Alabama PSC. On January 31, 2018, SCS, on behalf of the traditional electric operating companies (including the Company), filed with the FERC a reduction to the Company's open access transmission tariff charge for 2018 to reflect the revised federal corporate tax rate. See Note 3 to the financial statements under "Regulatory Matters – Rate RSE" for additional information.

See FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein and Note 5 to the financial statements under "Federal Tax Reform Legislation" for additional information.

The ultimate outcome of these matters cannot be determined at this time.

***Bonus Depreciation***

Under the Tax Reform Legislation, projects with binding contracts prior to September 28, 2017 and placed in service after September 27, 2017 remain eligible for bonus depreciation under the PATH Act. The PATH Act allowed for 50% bonus depreciation for 2015 through 2017, 40% bonus depreciation for 2018, and 30% bonus depreciation for 2019 and certain long-lived assets placed in service in 2020. Based on provisional estimates, approximately $200 million of positive cash flows is expected to result from bonus depreciation for the 2017 tax year and approximately $90 million for the 2018 tax year. Should Southern Company have a NOL in 2018, all of these cash flows may not be fully realized in 2018. See Note 5 to the financial statements under "Current and Deferred Income Taxes" for additional information.

**Other Matters**

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as standards for air, water, land, and protection of other natural resources, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by $CO_2$ and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters.

The ultimate outcome of such pending or potential litigation or regulatory matters cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

**ACCOUNTING POLICIES**

**Application of Critical Accounting Policies and Estimates**

The Company prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

***Utility Regulation***

The Company is subject to retail regulation by the Alabama PSC and wholesale regulation by the FERC. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, AROs, and pension and other postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and any requirement to refund these regulatory liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

***Federal Tax Reform Legislation***

Following the enactment of Tax Reform Legislation, the SEC staff issued Staff Accounting Bulletin 118 – "Income Tax Accounting Implications of the Tax Cuts and Jobs Act" (SAB 118), which provides for a measurement period of up to one year from the enactment date to complete accounting under GAAP for the tax effects of the legislation. Due to the complex and comprehensive nature of the enacted tax law changes, and their application under GAAP, the Company considers all amounts recorded in the financial statements as a result of Tax Reform Legislation to be "provisional" as discussed in SAB 118 and subject to revision. The Company is awaiting additional guidance from industry and income tax authorities in order to finalize its accounting. The ultimate impact of Tax Reform Legislation on deferred income tax assets and liabilities and the related regulatory assets and liabilities cannot be determined at this time. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation" herein and Notes 3 and 5 to the financial statements under "Retail Regulatory Matters – Rate RSE" and "Current and Deferred Income Taxes," respectively, for additional information.

***Asset Retirement Obligations***

AROs are computed as the fair value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities.

The liability for AROs primarily relates to the decommissioning of the Company's nuclear facility, Plant Farley, and facilities that are subject to the CCR Rule, principally ash ponds. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, asbestos removal related to ongoing repair and maintenance, disposal of polychlorinated biphenyls in certain transformers, and disposal of sulfur hexafluoride gas in certain substation breakers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, asbestos containing material within long-term assets not subject to ongoing repair and maintenance activities, and certain wireless communication towers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO.

The cost estimates for AROs related to the disposal of CCR are based on information using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure in place. As further analysis is performed and closure details are developed, the Company will continue to periodically update these cost estimates as necessary. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations – Coal Combustion Residuals" herein and Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" and "Nuclear Decommissioning" for additional information.

Given the significant judgment involved in estimating AROs, the Company considers the liabilities for AROs to be critical accounting estimates.

***Pension and Other Postretirement Benefits***

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on pension and other postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. For purposes of determining its liability related to the pension and other postretirement benefit plans, the Company discounts the future related cash flows using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments. For 2015 and prior years, the Company computed the interest cost component of its net periodic pension and other postretirement benefit plan expense using the same single-point discount rate. Beginning in 2016, the Company adopted a full yield curve approach for calculating the interest cost component whereby the discount rate for each year is applied to the liability for that specific year. As a result, the interest cost component of net periodic pension and other postretirement benefit plan expense decreased by approximately $24 million in 2016.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in an $9 million or less change in total annual benefit expense and a $128 million or less change in projected obligations.

The Company recorded pension costs of $9 million, $11 million, and $48 million in 2017, 2016, and 2015, respectively. Postretirement benefit costs for the Company were $3 million, $4 million, and $5 million in 2017, 2016, and 2015, respectively. Such amounts are dependent on several factors including trust earnings and changes to the plans. A portion of pension and other postretirement benefit costs is capitalized based on construction-related labor charges. Pension and other postretirement benefit costs are a component of the regulated rates and generally do not have a long-term effect on net income.

See Note 2 to the financial statements for additional information regarding pension and other postretirement benefits.

***Contingent Obligations***

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's results of operations, cash flows, or financial condition.

**Recently Issued Accounting Standards**

***Revenue***

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers* (ASC 606), replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the new standard is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

Most of the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term , as well as longer-term contractual commitments, including PPAs.

The Company has completed the evaluation of all revenue streams and determined that the adoption of ASC 606 will not change the current timing of revenue recognition for such transactions. Some revenue arrangements, such as energy-related derivatives, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed separately from revenues under ASC 606. The Company has concluded contributions in aid of construction are not in scope for ASC 606 and will continue to be accounted for as an offset to property, plant, and equipment.

The new standard is effective for reporting periods beginning after December 15, 2017. The Company applied the modified retrospective method of adoption effective January 1, 2018. The Company also utilized practical expedients which allowed it to apply the standard to open contracts at the date of adoption and to reflect the aggregate effect of all modifications when identifying performance obligations and allocating the transaction price for contracts modified before the effective date. Under the modified retrospective method of adoption, prior year reported results are not restated; however, a cumulative-effect adjustment to retained earnings at January 1, 2018 is recorded. In addition, quarterly disclosures will include comparative information on 2018 financial statement line items under current guidance. The adoption of ASC 606 did not result in a cumulative-effect adjustment .

***Leases***

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged . ASU 2016-02 is effective for fiscal years beginning after December 15, 2018 and the Company will adopt the new standard effective January 1, 2019.

The Company is currently implementing an information technology system along with the related changes to internal controls and accounting policies that will support the accounting for leases under ASU 2016-02. In addition, the Company has substantially completed a detailed inventory and analysis of its leases. In terms of rental charges and duration of contracts, the most significant leases relate to cellular towers, railcars, and a PPA where the Company is the lessee and outdoor lighting and to land where the Company is the lessor. The Company is currently analyzing pole attachment agreements and a lease determination has not been made at this time. While the Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

***Other***

On March 10, 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017-07). ASU 2017-07 requires that an employer report the service cost component in the same line item or items as other compensation costs and requires the other components of net periodic pension and postretirement benefit costs to be separately presented in the income statement outside of income from operations. Additionally, only the service cost component is eligible for capitalization, when applicable. However, all cost components remain eligible for capitalization under FERC regulations. ASU 2017-07 will be applied retrospectively for the presentation of the service cost component and the other components of net periodic pension and postretirement benefit costs in the income statement. The capitalization of only the service cost component of net periodic pension and postretirement benefit costs in assets will be applied on a prospective basis. ASU 2017-07 is effective for periods beginning after December 15, 2017. The presentation changes required for net periodic pension and postretirement benefit costs will result in a decrease in the Company's operating income and an increase in other income for 2016 and 2017 and are expected to result in a decrease in operating income and an increase in other income for 2018. The Company adopted ASU 2017-07 effective January 1, 2018 with no material impact on its financial statements.

On August 28, 2017, the FASB issued ASU No. 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities* (ASU 2017-12), amending the hedge accounting recognition and presentation requirements. ASU 2017-12 makes more financial and non-financial hedging strategies eligible for hedge accounting, amends the related presentation and disclosure requirements, and simplifies hedge effectiveness assessment requirements. ASU 2017-12 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

## FINANCIAL CONDITION AND LIQUIDITY

### Overview

The Company's financial condition remained stable at December 31, 2017. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to maintain existing generation facilities, to comply with environmental regulations including adding environmental modifications to certain existing generating units, to expand and improve transmission and distribution facilities, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2018 through 2020, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. The Company plans to finance future cash needs in excess of its operating cash flows primarily through external securities issuances, borrowings from financial institutions, or equity contributions from Southern Company. The Company plans to use commercial paper to manage seasonal variations in operating cash flows and for other working capital needs. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan and the nuclear decommissioning trust funds increased in value as of December 31, 2017 as compared to December 31, 2016. No contributions to the qualified pension plan were made for the year ended December 31, 2017 and no mandatory contributions to the qualified pension plan are anticipated during 2018 . The Company's funding obligations for the nuclear decommissioning trust fund are based on the most recent site study, and the next study is expected to be conducted in 2018. See Notes 1 and 2 to the financial statements under "Nuclear Decommissioning" and "Pension Plans," respectively, for additional information.

Net cash provided from operating activities totaled $ 1.8 billion for 2017, a decrease of $112 million as compared to 2016. The decrease in cash provided from operating activities was primarily due to the timing of income tax payments in 2017 and the receipt of income tax refunds in 2016 as a result of bonus depreciation, partially offset by the voluntary contribution to the qualified pension plan in 2016. Net cash provided from operating activities totaled $1.9 billion for 2016, a decrease of $193 million as compared to 2015. The decrease in cash provided from operating activities was primarily due to the collection of fuel cost recovery revenues and the voluntary contribution to the qualified pension plan, partially offset by the timing of income tax payments and refunds associated with bonus depreciation.

Net cash used for investing activities totaled $1.9 billion for 2017, $1.4 billion for 2016, and $1.5 billion for 2015. These activities were primarily related to gross property additions for environmental, steam generation, distribution, and transmission assets.

Net cash provided from financing activities totaled $163 million in 2017 primarily due to issuances of long-term debt and additional capital contributions from Southern Company, partially offset by the payment of common stock dividends and maturities of long-term debt. Net cash used for financing activities totaled $285 million in 2016 primarily due to the payment of common stock dividends and a redemption of long-term debt, partially offset by issuances of long-term debt and additional capital contributions from Southern Company. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for 2017 included increases of $1.3 billion in property, plant, and equipment primarily due to additions to distribution and transmission facilities and environmental and steam generation assets and $1.1 billion in long-term debt. Other significant changes included an increase of $2.0 billion in deferred credits related to income taxes and decreases of $1.9 billion in accumulated deferred income taxes primarily due to the change in tax rate resulting from Tax Reform Legislation and $0.6 billion in securities due within one year. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation" herein and Note 5 to the financial statements for additional information.

The Company's ratio of common equity to total capitalization plus short-term debt was 46.3% and 46.2% at December 31, 2017 and 2016, respectively. See Note 6 to the financial statements for additional information.

**Sources of Capital**

The Company plans to obtain the funds to meet its future capital needs from sources similar to those used in the past, which were primarily from operating cash flows, external security issuances, borrowings from financial institutions, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors.

Security issuances are subject to regulatory approval by the Alabama PSC. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended. The amounts of securities authorized by the Alabama PSC are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company in the Southern Company system.

The Company's current liabilities sometimes exceed current assets because of long-term debt maturities and the periodic use of short-term debt as a funding source, as well as significant seasonal fluctuations in cash needs.

At December 31, 2017, the Company had approximately $544 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2017 were as follows:

| Expires | | | | | Expires Within One Year | |
|---|---|---|---|---|---|---|
| 2018 | 2020 | 2022 | Total | Unused | Term Out | No Term Out |
| *(in millions)* | | | *(in millions)* | | *(in millions)* | |
| $ 35 | $ 500 | $ 800 | $ 1,335 | $ 1,335 | $ — | $ 35 |

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

In May 2017 and September 2017, the Company amended its $800 million and $500 million multi-year credit arrangements, which, among other things, extended the maturity dates from 2020 to 2022 and 2018 to 2020, respectively, as reflected in the table above.

Most of these bank credit arrangements, as well as the Company's term loan arrangements, contain covenants that limit debt levels and contain cross-acceleration provisions to other indebtedness (including guarantee obligations) of the Company. Such cross-acceleration provisions to other indebtedness would trigger an event of default if the Company defaulted on indebtedness, the payment of which was then accelerated. At December 31, 2017, the Company was in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings.

Subject to applicable market conditions, the Company expects to renew or replace its bank credit arrangements as needed, prior to expiration. In connection therewith, the Company may extend the maturity dates and/or increase or decrease the lending commitments thereunder.

A portion of the unused credit with banks is allocated to provide liquidity support to the Company's pollution control revenue bonds and commercial paper programs. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support was $854 million as of December 31, 2017. In addition, at December 31, 2017, the Company had $120 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

The Company also has substantial cash flow from operating activities and access to the capital markets, including a commercial paper program, to meet liquidity needs. The Company may meet short-term cash needs through its commercial paper program. The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional electric operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each traditional electric operating company under these arrangements are several and there is no cross-affiliate credit support.

Details of short-term borrowings were as follows:

| | Short-term Debt at the End of the Period | | Short-term Debt During the Period (*) | | |
|---|---|---|---|---|---|
| | Amount Outstanding | Weighted Average Interest Rate | Average Amount Outstanding | Weighted Average Interest Rate | Maximum Amount Outstanding |
| | *(in millions)* | | *(in millions)* | | *(in millions)* |
| **December 31, 2017** | **$ 3** | **3.7%** | **$ 25** | **1.3%** | **$ 223** |
| December 31, 2016 | $ — | —% | $ 16 | 0.6% | $ 200 |
| December 31, 2015 | $ — | —% | $ 14 | 0.2% | $ 100 |

(*) Average and maximum amounts are based upon daily balances during the 12-month periods ended December 31, 2017, 2016, and 2015.

The Company believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and operating cash flows.

### Financing Activities

In February 2017, the Company repaid at maturity $200 million aggregate principal amount of Series 2007A 5.55% Senior Notes.

In March 2017, the Company issued $550 million aggregate principal amount of Series 2017A 2.45% Senior Notes due March 30, 2022. The proceeds were used to repay the Company's short-term indebtedness and for general corporate purposes, including the Company's continuous construction program.

In August 2017, the Company repaid at maturity $36.1 million aggregate principal amount of Series 1993-A, 1993-B, and 1993-C Industrial Development Board of the City of Mobile, Alabama Pollution Control Revenue Refunding Bonds (Alabama Power Company Project).

In September 2017, the Company issued 10 million shares ($250 million aggregate stated capital) of 5.00% Class A Preferred Stock, Cumulative, Par Value $1 Per Share (Stated Capital $25 Per Share). The proceeds were used in October 2017 to redeem all 2 million shares ($50 million aggregate stated capital) of 6.50% Series Preference Stock, 6 million shares ($150 million aggregate stated capital) of 6.45% Series Preference Stock, and 1.52 million shares ($38 million aggregate stated capital) of 5.83% Class A Preferred Stock and for other general corporate purposes, including the Company's continuous construction program.

In October 2017, the Company repaid at maturity $325 million aggregate principal amount of Series Q 5.50% Senior Notes.

In November 2017, the Company issued $550 million aggregate principal amount of Series 2017B 3.70% Senior Notes due December 1, 2047. The proceeds were used for general corporate purposes, including the Company's continuous construction program.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

### Credit Rating Risk

At December 31, 2017, the Company did not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB and/or Baa2 or below. These contracts are primarily for physical electricity purchases, fuel purchases, fuel transportation and storage, energy price risk management, and transmission.

The maximum potential collateral requirements under these contracts at December 31, 2017 were as follows:

| Credit Ratings | Maximum Potential Collateral Requirements |
|---|---|
| | *(in millions)* |
| At BBB and/or Baa2 | $ 1 |
| At BBB- and/or Baa3 | $ 2 |
| Below BBB- and/or Baa3 | $ 323 |

Included in these amounts are certain agreements that could require collateral in the event that either the Company or Georgia Power has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact the ability of the Company to access capital markets and would be likely to impact the cost at which it does so.

On March 24, 2017, S&P revised its consolidated credit rating outlook for Southern Company and its subsidiaries (including the Company) from stable to negative.

On January 19, 2018, Moody's revised its rating outlook for the Company from stable to negative.

While it is unclear how the credit rating agencies and regulatory authorities may respond to the Tax Reform Legislation, certain financial metrics, such as the funds from operations to debt percentage, used by the credit rating agencies to assess Southern Company and its subsidiaries, including the Company, may be negatively impacted. Absent actions by Southern Company and its subsidiaries, including the Company, to mitigate the resulting impacts, which, among other alternatives, could include adjusting capital structure and/or monetizing regulatory assets, the Company's credit ratings could be negatively affected. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate RSE" for additional information.

**Market Price Risk**

Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives designated as hedges. The weighted average interest rate on $1.1 billion of long-term variable interest rate exposure at December 31, 2017 was 2.3%. If the Company sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would affect annualized interest expense by approximately $11 million at December 31, 2017. See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and financial hedge contracts for natural gas purchases. The Company continues to manage a retail fuel-hedging program implemented per the guidelines of the Alabama PSC. The Company had no material change in market risk exposure for the year ended December 31, 2017 when compared to the year ended December 31, 2016.

In addition, Rate ECR allows the recovery of specific costs associated with the sales of natural gas that become necessary due to operating considerations at the Company's electric generating facilities. Rate ECR also allows recovery of the cost of financial instruments used for hedging market price risk up to 75% of the budgeted annual amount of natural gas purchases. The Company may not engage in natural gas hedging activities that extend beyond a rolling 42-month window. Also, the premiums paid for natural gas financial options may not exceed 5% of the Company's natural gas budget for that year.

The changes in fair value of energy-related derivative contracts are substantially attributable to both the volume and the price of natural gas. For the years ended December 31, the changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, were as follows:

| | **2017 Changes** | 2016 Changes |
|---|---|---|
| | Fair Value | |
| | *(in millions)* | |
| Contracts outstanding at the beginning of the period, assets (liabilities), net | **$ 12** | $ (54) |
| Contracts realized or settled | **(1)** | 39 |
| Current period changes (*) | **(17)** | 27 |
| Contracts outstanding at the end of the period, assets (liabilities), net | **$ (6)** | $ 12 |

(*) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The net hedge volumes of energy-related derivative contracts, for the years ended December 31 were as follows:

| | **2017** | 2016 |
|---|---|---|
| | mmBtu Volume | |
| | *(in millions)* | |
| Commodity – Natural gas swaps | **64** | 68 |
| Commodity – Natural gas options | **5** | 6 |
| Total hedge volume | **69** | 74 |

The weighted average swap contract cost above market prices was approximately $0.08 per mmBtu as of December 31, 2017 and below market prices was approximately $0.14 per mmBtu as of December 31, 2016. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. Substantially all of the natural gas hedge gains and losses are recovered through the Company's retail energy cost recovery clause.

At December 31, 2017 and 2016, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were related to the Company's fuel-hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the energy cost recovery clause. Certain other gains and losses on energy-related derivatives, designated as cash flow hedges, are initially deferred in OCI before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2 of the fair value hierarchy. See Note 10 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are primarily Level 2 of the fair value hierarchy, at December 31, 2017 were as follows:

| | Fair Value Measurements December 31, 2017 | | |
|---|---|---|---|
| | Total | Maturity | |
| | Fair Value | Year 1 | Years 2&3 |
| | | *(in millions)* | |
| Level 1 | $ — | $ — | $ — |
| Level 2 | 6 | 4 | 2 |
| Level 3 | — | — | — |
| Fair value of contracts outstanding at end of period | $ 6 | $ 4 | $ 2 |

The Company is exposed to market price risk in the event of nonperformance by counterparties to energy-related and interest rate derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P, or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

**Capital Requirements and Contractual Obligations**

The construction program of the Company is currently estimated to total $2.2 billion for 2018, $1.6 billion for 2019, $1.6 billion for 2020, $1.7 billion for 2021, and $1.4 billion for 2022. The construction program includes capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental laws and regulations included in these amounts are $581 million for 2018, $110 million for 2019, $163 million for 2020, $258 million for 2021, and $268 million for 2022. These estimated expenditures do not include any potential compliance costs associated with the regulation of $CO_2$ emissions from fossil fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations" and "– Global Climate Issues" herein for additional information.

The Company also anticipates costs associated with closure in place and monitoring of ash ponds in accordance with the CCR Rule, which are reflected in the Company's ARO liabilities. These costs, which could change as the Company continues to refine its assumptions underlying the cost estimates and evaluate the method and timing of compliance activities, are estimated to be $0.3 million for 2018, $111 million for 2019, $90 million for 2020, $94 million for 2021, and $96 million for 2022. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information. Costs associated with the CCR Rule are expected to be recovered through Rate CNP Compliance.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental laws and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing generating units, to meet regulatory requirements; changes in the expected environmental compliance program; changes in FERC rules and regulations; Alabama PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

As a result of NRC requirements, the Company has external trust funds for nuclear decommissioning costs; however, the Company currently has no additional funding requirements. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the Alabama PSC and the FERC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, pension and other postretirement benefit plans, preferred stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 6, 7, and 11 to the financial statements for additional information.

**MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)**
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**Contractual Obligations**

Contractual obligations at December 31, 2017 were as follows:

| | 2018 | 2019- 2020 | 2021- 2022 | After 2022 | Total |
|---|---|---|---|---|---|
| | | | *(in millions)* | | |
| Long-term debt [(a)] — | | | | | |
| Principal | $ — | $ 450 | $ 1,060 | $ 6,176 | $ 7,686 |
| Interest | 304 | 598 | 561 | 4,408 | 5,871 |
| Preferred stock dividends [(b)] | 15 | 29 | 29 | — | 73 |
| Financial derivative obligations [(c)] | 6 | 4 | — | — | 10 |
| Operating leases [(d)] | 21 | 40 | 24 | 20 | 105 |
| Capital Lease | 1 | 1 | 1 | 2 | 5 |
| Purchase commitments — | | | | | |
| Capital [(e)] | 2,053 | 2,972 | 2,914 | — | 7,939 |
| Fuel [(f)] | 974 | 1,197 | 459 | 238 | 2,868 |
| Purchased power [(g)] | 78 | 171 | 186 | 606 | 1,041 |
| Other [(h)] | 47 | 73 | 59 | 313 | 492 |
| Pension and other postretirement benefit plans [(i)] | 19 | 36 | — | — | 55 |
| Total | $ 3,518 | $ 5,571 | $ 5,293 | $ 11,763 | $ 26,145 |

(a) All amounts are reflected based on final maturity dates. The Company plans to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of December 31, 2017, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).

(b) Preferred stock does not mature; therefore, amounts are provided for the next five years only.

(c) Includes derivative liabilities related to cash flow hedges of forecasted debt, as well as energy-related derivatives. For additional information, see Notes 1 and 11 to the financial statements.

(d) Excludes PPAs that are accounted for as leases and are included in purchased power.

(e) The Company provides estimated capital expenditures for a five-year period, including capital expenditures associated with environmental regulations. These amounts exclude contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements which are reflected in "Fuel" and "Other," respectively. At December 31, 2017 , purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations" herein for additional information.

(f) Includes commitments to purchase coal, nuclear fuel, and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2017 .

(g) Estimated minimum long-term obligations for various long-term commitments for the purchase of capacity and energy.

(h) Includes long-term service agreements and contracts for the procurement of limestone. Long-term service agreements include price escalation based on inflation indices.

(i) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

**Cautionary Statement Regarding Forward-Looking Statements**

The Company's 2017 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning regulated rates, customer and sales growth, economic conditions, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, pending or potential litigation matters, access to sources of capital, projections for the qualified pension plan , postretirement benefit plans, and nuclear decommissioning trust fund contributions, financing activities, filings with state and federal regulatory authorities, impacts of the Tax Reform Legislation, federal income tax benefits, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including environmental laws and regulations governing air, water, land, and protection of other natural resources , and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- the uncertainty surrounding the recently enacted Tax Reform Legislation, including implementing regulations and IRS interpretations, actions that may be taken in response by regulatory authorities, and its impact, if any, on the credit ratings of the Company;
- current and future litigation or regulatory investigations, proceedings, or inquiries ;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of facilities, to construct facilities in accordance with the requirements of permits and licenses , and to satisfy any environmental performance standards ;
- investment performance of the Company's employee and retiree benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- the inherent risks involved in operating nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, and financial risks;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or physical attack and the threat of physical attacks;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on foreign currency exchange rates, counterparty performance, and the economy in general ;

- the ability of the Company to obtain additional generating capacity (or sell excess generating capacity) at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports filed by the Company from time to time with the SEC.

**The Company expressly disclaims any obligation to update any forward-looking statements.**

**STATEMENTS OF INCOME**
**For the Years Ended December 31, 2017 , 2016 , and 2015**
**Alabama Power Company 2017 Annual Report**

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| **Operating Revenues:** | | | |
| Retail revenues | **$ 5,458** | $ 5,322 | $ 5,234 |
| Wholesale revenues, non-affiliates | **276** | 283 | 241 |
| Wholesale revenues, affiliates | **97** | 69 | 84 |
| Other revenues | **208** | 215 | 209 |
| Total operating revenues | **6,039** | 5,889 | 5,768 |
| **Operating Expenses:** | | | |
| Fuel | **1,225** | 1,297 | 1,342 |
| Purchased power, non-affiliates | **170** | 166 | 171 |
| Purchased power, affiliates | **158** | 168 | 180 |
| Other operations and maintenance | **1,652** | 1,510 | 1,501 |
| Depreciation and amortization | **736** | 703 | 643 |
| Taxes other than income taxes | **384** | 380 | 368 |
| Total operating expenses | **4,325** | 4,224 | 4,205 |
| **Operating Income** | **1,714** | 1,665 | 1,563 |
| **Other Income and (Expense):** | | | |
| Allowance for equity funds used during construction | **39** | 28 | 60 |
| Interest expense, net of amounts capitalized | **(305)** | (302) | (274) |
| Other income (expense), net | **(14)** | (21) | (32) |
| Total other income and (expense) | **(280)** | (295) | (246) |
| **Earnings Before Income Taxes** | **1,434** | 1,370 | 1,317 |
| Income taxes | **568** | 531 | 506 |
| **Net Income** | **866** | 839 | 811 |
| **Dividends on Preferred and Preference Stock** | **18** | 17 | 26 |
| **Net Income After Dividends on Preferred and Preference Stock** | **$ 848** | $ 822 | $ 785 |

The accompanying notes are an integral part of these financial statements.

**STATEMENTS OF COMPREHENSIVE INCOME**
**For the Years Ended December 31, 2017 , 2016 , and 2015**
**Alabama Power Company 2017 Annual Report**

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| **Net Income** | **$ 866** | $ 839 | $ 811 |
| Other comprehensive income (loss): | | | |
| Qualifying hedges: | | | |
| Changes in fair value, net of tax of $(1), $(1), and $(3), respectively | **1** | (2) | (5) |
| Reclassification adjustment for amounts included in net income, net of tax of $2, $2, and $1, respectively | **3** | 4 | 2 |
| Total other comprehensive income (loss) | **4** | 2 | (3) |
| **Comprehensive Income** | **$ 870** | $ 841 | $ 808 |

The accompanying notes are an integral part of these financial statements.

**STATEMENTS OF CASH FLOWS**
**For the Years Ended December 31, 2017 , 2016 , and 2015**
**Alabama Power Company 2017 Annual Report**

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| **Operating Activities:** | | | |
| Net income | $ 866 | $ 839 | $ 811 |
| Adjustments to reconcile net income to net cash provided from operating activities — | | | |
| Depreciation and amortization, total | 888 | 844 | 780 |
| Deferred income taxes | 409 | 407 | 388 |
| Allowance for equity funds used during construction | (39) | (28) | (60) |
| Pension and postretirement funding | (2) | (133) | — |
| Other, net | (14) | (102) | 15 |
| Changes in certain current assets and liabilities — | | | |
| -Receivables | (168) | 94 | (160) |
| -Other current assets | (16) | 1 | 40 |
| -Accounts payable | 71 | 73 | 3 |
| -Accrued taxes | (84) | 93 | 138 |
| -Retail fuel cost over recovery | (76) | (162) | 191 |
| -Other current liabilities | 2 | 23 | (4) |
| Net cash provided from operating activities | 1,837 | 1,949 | 2,142 |
| **Investing Activities:** | | | |
| Property additions | (1,882) | (1,272) | (1,367) |
| Nuclear decommissioning trust fund purchases | (237) | (352) | (439) |
| Nuclear decommissioning trust fund sales | 237 | 351 | 438 |
| Cost of removal net of salvage | (112) | (94) | (71) |
| Change in construction payables | 161 | (37) | (15) |
| Other investing activities | (43) | (34) | (34) |
| Net cash used for investing activities | (1,876) | (1,438) | (1,488) |
| **Financing Activities:** | | | |
| Increase in notes payable, net | 3 | — | — |
| Proceeds — | | | |
| Senior notes | 1,100 | 400 | 975 |
| Preferred stock | 250 | — | — |
| Pollution control revenue bonds | — | — | 80 |
| Other long-term debt | — | 45 | — |
| Capital contributions from parent company | 361 | 260 | 22 |
| Redemptions and repurchases — | | | |
| Senior notes | (525) | (200) | (650) |
| Preferred and preference stock | (238) | — | (412) |
| Pollution control revenue bonds | (36) | — | (134) |
| Payment of common stock dividends | (714) | (765) | (571) |
| Other financing activities | (38) | (25) | (43) |
| Net cash provided from (used for) financing activities | 163 | (285) | (733) |
| **Net Change in Cash and Cash Equivalents** | 124 | 226 | (79) |
| **Cash and Cash Equivalents at Beginning of Year** | 420 | 194 | 273 |
| **Cash and Cash Equivalents at End of Year** | $ 544 | $ 420 | $ 194 |
| **Supplemental Cash Flow Information:** | | | |
| Cash paid (received) during the period for — | | | |
| Interest (net of $15, $11, and $22 capitalized, respectively) | $ 285 | $ 277 | $ 250 |
| Income taxes (net of refunds) | 236 | (108) | 121 |
| Noncash transactions — Accrued property additions at year-end | 245 | 84 | 121 |

The accompanying notes are an integral part of these financial statements.

**BALANCE SHEETS**
**At December 31, 2017 and 2016**
**Alabama Power Company 2017 Annual Report**

| **Assets** | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Current Assets:** | | |
| Cash and cash equivalents | **$ 544** | $ 420 |
| Receivables — | | |
| Customer accounts receivable | **355** | 348 |
| Unbilled revenues | **162** | 146 |
| Affiliated | **43** | 40 |
| Other accounts and notes receivable | **55** | 27 |
| Accumulated provision for uncollectible accounts | **(9)** | (10) |
| Fossil fuel stock | **184** | 205 |
| Materials and supplies | **458** | 435 |
| Other regulatory assets, current | **124** | 149 |
| Other current assets | **90** | 45 |
| Total current assets | **2,006** | 1,805 |
| **Property, Plant, and Equipment:** | | |
| In service | **27,326** | 26,031 |
| Less: Accumulated provision for depreciation | **9,563** | 9,112 |
| Plant in service, net of depreciation | **17,763** | 16,919 |
| Nuclear fuel, at amortized cost | **339** | 336 |
| Construction work in progress | **908** | 491 |
| Total property, plant, and equipment | **19,010** | 17,746 |
| **Other Property and Investments:** | | |
| Equity investments in unconsolidated subsidiaries | **67** | 66 |
| Nuclear decommissioning trusts, at fair value | **903** | 792 |
| Miscellaneous property and investments | **124** | 112 |
| Total other property and investments | **1,094** | 970 |
| **Deferred Charges and Other Assets:** | | |
| Deferred charges related to income taxes | **239** | 525 |
| Deferred under recovered regulatory clause revenues | **54** | 150 |
| Other regulatory assets, deferred | **1,272** | 1,157 |
| Other deferred charges and assets | **189** | 163 |
| Total deferred charges and other assets | **1,754** | 1,995 |
| **Total Assets** | **$ 23,864** | $ 22,516 |

The accompanying notes are an integral part of these financial statements.

**BALANCE SHEETS**
**At December 31, 2017 and 2016**
**Alabama Power Company 2017 Annual Report**

| **Liabilities and Stockholder's Equity** | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Current Liabilities:** | | |
| Securities due within one year | **$ —** | $ 561 |
| Accounts payable — | | |
| Affiliated | **327** | 297 |
| Other | **585** | 433 |
| Customer deposits | **92** | 88 |
| Accrued taxes — | | |
| Accrued income taxes | **9** | 45 |
| Other accrued taxes | **45** | 42 |
| Accrued interest | **77** | 78 |
| Accrued compensation | **205** | 193 |
| Other regulatory liabilities, current | **1** | 85 |
| Other current liabilities | **59** | 76 |
| Total current liabilities | **1,400** | 1,898 |
| **Long-Term Debt** (See accompanying statements) | **7,628** | 6,535 |
| **Deferred Credits and Other Liabilities:** | | |
| Accumulated deferred income taxes | **2,760** | 4,654 |
| Deferred credits related to income taxes | **2,082** | 65 |
| Accumulated deferred ITCs | **112** | 110 |
| Employee benefit obligations | **304** | 300 |
| Asset retirement obligations | **1,702** | 1,503 |
| Other cost of removal obligations | **609** | 684 |
| Other regulatory liabilities, deferred | **84** | 100 |
| Other deferred credits and liabilities | **63** | 63 |
| Total deferred credits and other liabilities | **7,716** | 7,479 |
| **Total Liabilities** | **16,744** | 15,912 |
| **Redeemable Preferred Stock** (See accompanying statements) | **291** | 85 |
| **Preference Stock** (See accompanying statements) | **—** | 196 |
| **Common Stockholder's Equity** (See accompanying statements) | **6,829** | 6,323 |
| **Total Liabilities and Stockholder's Equity** | **$ 23,864** | $ 22,516 |
| **Commitments and Contingent Matters** (See notes) | | |

The accompanying notes are an integral part of these financial statements.

**STATEMENTS OF CAPITALIZATION**
**At December 31, 2017 and 2016**
**Alabama Power Company 2017 Annual Report**

| | 2017 | 2016 | 2017 | 2016 |
|---|---|---|---|---|
| | *(in millions)* | | *(percent of total)* | |
| **Long-Term Debt:** | | | | |
| Long-term debt payable to affiliated trusts — | | | | |
| Variable rate (4.44% at 12/31/17) due 2042 | **$ 206** | $ 206 | | |
| Long-term notes payable — | | | | |
| 5.50% to 5.55% due 2017 | — | 525 | | |
| 5.125% due 2019 | **200** | 200 | | |
| 3.375% due 2020 | **250** | 250 | | |
| 2.38% to 3.95% due 2021 | **220** | 220 | | |
| 2.45% to 5.875% due 2022 | **750** | 200 | | |
| 2.80% to 6.125% due 2023-2047 | **4,975** | 4,425 | | |
| Variable rates (2.55% to 2.786% at 12/31/17) due 2021 | **25** | 25 | | |
| Total long-term notes payable | **6,420** | 5,845 | | |
| Other long-term debt — | | | | |
| Pollution control revenue bonds — | | | | |
| 1.625% to 1.85% due 2034 | **207** | 207 | | |
| Variable rates (0.77% to 0.79% at 1/1/17) due 2017 | — | 36 | | |
| Variable rates (1.86% to 1.87% at 12/31/17) due 2021 | **65** | 65 | | |
| Variable rates (1.70% to 1.87% at 12/31/17) due 2024-2038 | **788** | 788 | | |
| Total other long-term debt | **1,060** | 1,096 | | |
| Capitalized lease obligations | **4** | 4 | | |
| Unamortized debt premium (discount), net | **(11)** | (9) | | |
| Unamortized debt issuance expense | **(51)** | (46) | | |
| Total long-term debt (annual interest requirement — $305 million) | **7,628** | 7,096 | | |
| Less amount due within one year | — | 561 | | |
| Long-term debt excluding amount due within one year | **7,628** | 6,535 | **51.7%** | 49.7% |
| **Redeemable Preferred Stock:** | | | | |
| Cumulative redeemable preferred stock | | | | |
| $100 par or stated value — 4.20% to 4.92% | | | | |
| Authorized — 3,850,000 shares | | | | |
| Outstanding — 475,115 shares | **48** | 48 | | |
| $1 par value — | | | | |
| Authorized — 27,500,000 shares | | | | |
| Outstanding — 2017: 5.00% — 10,000,000 shares: $25 stated value | | | | |
| — 2016: 5.83% — 1,520,000 shares: $25 stated value | | | | |
| (annual dividend requirement — $15 million) | **243** | 37 | | |
| Total redeemable preferred stock | **291** | 85 | **2.0** | 0.7 |
| **Preference Stock:** | | | | |
| $1 par value — 6.45% to 6.50% | | | | |
| Authorized — 40,000,000 shares | | | | |
| Outstanding — 2017: no shares | | | | |
| — 2016: 8,000,000 shares (non-cumulative): $25 stated value | — | 196 | — | 1.5 |
| **Common Stockholder's Equity:** | | | | |
| Common stock, par value $40 per share — | | | | |
| Authorized — 40,000,000 shares | | | | |
| Outstanding — 30,537,500 shares | **1,222** | 1,222 | | |
| Paid-in capital | **2,986** | 2,613 | | |
| Retained earnings | **2,647** | 2,518 | | |
| Accumulated other comprehensive loss | **(26)** | (30) | | |

| | | | | | |
|---|---|---|---|---|---|
| Total common stockholder's equity | | **6,829** | 6,323 | **46.3** | 48.1 |
| **Total Capitalization** | **$** | **14,748** | $ 13,139 | **100.0%** | 100.0% |

The accompanying notes are an integral part of these financial statements.

**STATEMENTS OF COMMON STOCKHOLDER'S EQUITY**
**For the Years Ended December 31, 2017 , 2016 , and 2015**
**Alabama Power Company 2017 Annual Report**

| | Number of Common Shares Issued | Common Stock | Paid-In Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|---|---|---|---|---|---|---|
| | | | | *(in millions)* | | |
| **Balance at December 31, 2014** | 31 | $ 1,222 | $ 2,304 | $ 2,255 | $ (29) | $ 5,752 |
| Net income after dividends on preferred and preference stock | — | — | — | 785 | — | 785 |
| Capital contributions from parent company | — | — | 37 | — | — | 37 |
| Other comprehensive income (loss) | — | — | — | — | (3) | (3) |
| Cash dividends on common stock | — | — | — | (571) | — | (571) |
| Other | — | — | — | (8) | — | (8) |
| **Balance at December 31, 2015** | 31 | 1,222 | 2,341 | 2,461 | (32) | 5,992 |
| Net income after dividends on preferred and preference stock | — | — | — | 822 | — | 822 |
| Capital contributions from parent company | — | — | 272 | — | — | 272 |
| Other comprehensive income (loss) | — | — | — | — | 2 | 2 |
| Cash dividends on common stock | — | — | — | (765) | — | (765) |
| **Balance at December 31, 2016** | **31** | **1,222** | **2,613** | **2,518** | **(30)** | **6,323** |
| Net income after dividends on preferred and preference stock | **—** | **—** | **—** | **848** | **—** | **848** |
| Capital contributions from parent company | **—** | **—** | **373** | **—** | **—** | **373** |
| Other comprehensive income (loss) | **—** | **—** | **—** | **—** | **4** | **4** |
| Cash dividends on common stock | **—** | **—** | **—** | **(714)** | **—** | **(714)** |
| Other | **—** | **—** | **—** | **(5)** | **—** | **(5)** |
| **Balance at December 31, 2017** | **31** | **$ 1,222** | **$ 2,986** | **$ 2,647** | **$ (26)** | **$ 6,829** |

The accompanying notes are an integral part of these financial statements.

**NOTES TO FINANCIAL STATEMENTS**
**Alabama Power Company 2017 Annual Report**

**Index to the Notes to Financial Statements**

## 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

### General

Alabama Power Company (the Company) is a wholly-owned subsidiary of Southern Company, which is the parent company of the Company and three other traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), SCS, Southern Linc, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, PowerSecure, Inc. (PowerSecure) (as of May 9, 2016), and other direct and indirect subsidiaries. The traditional electric operating companies – the Company, Georgia Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. The Company provides electric service to retail and wholesale customers within its traditional service territory located in the State of Alabama in addition to wholesale customers in the Southeast. Southern Power develops, constructs, acquires, owns, and manages power generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Company Gas distributes natural gas through utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. Southern Linc provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber optics services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases and for other electric services. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants, including the Company's Plant Farley. PowerSecure is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure.

The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities (VIEs) where the Company has an equity investment, but is not the primary beneficiary.

The Company is subject to regulation by the FERC and the Alabama PSC. As such, the Company's financial statements reflect the effects of rate regulation in accordance with GAAP and comply with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

### Recently Issued Accounting Standards

#### *Revenue*

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers* (ASC 606), replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the new standard is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

Most of the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term , as well as longer-term contractual commitments, including PPAs.

The Company has completed the evaluation of all revenue streams and determined that the adoption of ASC 606 will not change the current timing of revenue recognition for such transactions. Some revenue arrangements, such as energy-related derivatives, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed separately from revenues under ASC 606. The Company has concluded contributions in aid of construction are not in scope for ASC 606 and will continue to be accounted for as an offset to property, plant, and equipment.

The new standard is effective for reporting periods beginning after December 15, 2017. The Company applied the modified retrospective method of adoption effective January 1, 2018. The Company also utilized practical expedients which allowed it to apply the standard to open contracts at the date of adoption and to reflect the aggregate effect of all modifications when identifying performance obligations and allocating the transaction price for contracts modified before the effective date. Under the modified retrospective method of adoption, prior year reported results are not restated; however, a cumulative-effect adjustment to retained earnings at January 1, 2018 is recorded. In addition, quarterly disclosures will include comparative information on 2018 financial statement line items under current guidance. The adoption of ASC 606 did not result in a cumulative-effect adjustment .

***Leases***

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged . ASU 2016-02 is effective for fiscal years beginning after December 15, 2018 and the Company will adopt the new standard effective January 1, 2019.

The Company is currently implementing an information technology system along with the related changes to internal controls and accounting policies that will support the accounting for leases under ASU 2016-02. In addition, the Company has substantially completed a detailed inventory and analysis of its leases. In terms of rental charges and duration of contracts, the most significant leases relate to cellular towers, railcars, and a PPA where the Company is the lessee and outdoor lighting and to land where the Company is the lessor. The Company is currently analyzing pole attachment agreements and a lease determination has not been made at this time. While the Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

***Other***

In March 2016, the FASB issued ASU No. 2016-09, *Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Notes 5 and 8 for disclosures impacted by ASU 2016-09.

On March 10, 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017-07). ASU 2017-07 requires that an employer report the service cost component in the same line item or items as other compensation costs and requires the other components of net periodic pension and postretirement benefit costs to be separately presented in the income statement outside of income from operations. Additionally, only the service cost component is eligible for capitalization, when applicable. However, all cost components remain eligible for capitalization under FERC regulations. ASU 2017-07 will be applied retrospectively for the presentation of the service cost component and the other components of net periodic pension and postretirement benefit costs in the income statement. The capitalization of only the service cost component of net periodic pension and postretirement benefit costs in assets will be applied on a prospective basis. ASU 2017-07 is effective for periods beginning after December 15, 2017. The presentation changes required for net periodic pension and postretirement benefit costs will result in a decrease in the Company's operating income and an increase in other income for 2016 and 2017 and are expected to result in a decrease in operating income and an increase in other income for 2018. The Company adopted ASU 2017-07 effective January 1, 2018 with no material impact on its financial statements.

On August 28, 2017, the FASB issued ASU No. 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities* (ASU 2017-12), amending the hedge accounting recognition and presentation requirements. ASU 2017-12 makes more financial and non-financial hedging strategies eligible for hedge accounting, amends the related presentation and disclosure requirements, and simplifies hedge effectiveness assessment requirements. ASU 2017-12 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

**Affiliate Transactions**

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations, construction management, and power pool transactions. Costs for these services amounted to $479 million , $460 million , and $438 million during 2017 , 2016 , and 2015 , respectively. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies. See Note 7 under "Operating Leases" for information on leases of cellular tower space for the Company's digital wireless communications equipment.

The Company has an agreement with Southern Nuclear under which the following nuclear-related services are rendered to the Company at cost: general executive and advisory services, general operations, management and technical services, administrative services including procurement, accounting, employee relations, systems and procedures services, strategic planning and budgeting services, and other services with respect to business and operations. Costs for these services amounted to $248 million , $249 million , and $243 million during 2017 , 2016 , and 2015 , respectively.

The Company jointly owns Plant Greene County with Mississippi Power. The Company has an agreement with Mississippi Power under which the Company operates Plant Greene County, and Mississippi Power reimburses the Company for its proportionate share of non-fuel expenses, which totaled $9 million in 2017 , $13 million in 2016 , and $11 million in 2015 . Mississippi Power also reimbursed the Company for any direct fuel purchases delivered from one of the Company's transfer facilities. There were no such fuel purchases in 2017 and 2016 and $8 million in 2015 . See Note 4 for additional information.

The Company has an agreement with Gulf Power under which the Company made transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA from a combined cycle plant located in Autauga County, Alabama. Under a related tariff, the Company received $11 million in 2017, $12 million in 2016, and $14 million in 2015 and expects to recover a total of approximately $61 million from 2018 through 2023 from Gulf Power.

In September 2016, Southern Company Gas acquired a 50% equity interest in Southern Natural Gas Company, L.L.C. (SNG). Prior to completion of the acquisition, SCS, as agent for the Company, had entered into a long-term interstate natural gas transportation agreement with SNG. The interstate transportation service provided to the Company by SNG pursuant to this agreement is governed by the terms and conditions of SNG's natural gas tariff and is subject to FERC regulation. Transportation costs under this agreement were approximately $9 million in 2017 and $2 million for the period subsequent to Southern Company Gas' investment in SNG through December 31, 2016 .

The Company has agreements with PowerSecure for services related to utility infrastructure construction, distributed energy, and energy efficiency projects. Costs for these services amounted to approximately $11 million for 2017 and were immaterial for 2016.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2017 , 2016 , or 2015 .

Also, see Note 4 for information regarding the Company's ownership in a PPA and a gas pipeline ownership agreement with SEGCO.

The traditional electric operating companies, including the Company and Southern Power, may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

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**Regulatory Assets and Liabilities**

The Company is subject to accounting requirements for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

| | **2017** | 2016 | Note |
|---|---|---|---|
| | *(in millions)* | | |
| Retiree benefit plans | $ 946 | $ 947 | (i,j) |
| Deferred income tax charges | 240 | 526 | (a,k,n) |
| Regulatory clauses | 142 | — | (m) |
| Vacation pay | 70 | 69 | (c,j) |
| Loss on reacquired debt | 62 | 68 | (b) |
| Nuclear outage | 56 | 70 | (d) |
| Remaining net book value of retired assets | 54 | 69 | (l) |
| Under/(over) recovered regulatory clause revenues | 53 | 76 | (d) |
| Other regulatory assets | 51 | 50 | (f) |
| Fuel-hedging losses | 7 | 1 | (e,j) |
| Deferred income tax credits | (2,082) | (65) | (a,n) |
| Other cost of removal obligations | (609) | (684) | (a) |
| Natural disaster reserve | (38) | (69) | (h) |
| Asset retirement obligations | (33) | 12 | (a) |
| Other regulatory liabilities | (7) | (23) | (e,g) |
| Total regulatory assets (liabilities), net | $ (1,088) | $ 1,047 | |

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Asset retirement and removal assets and liabilities are recorded, deferred income tax assets are recovered, and deferred income tax credits are amortized over the related property lives, which may range up to 50 years . Asset retirement and other cost of removal assets and liabilities will be settled and trued up following completion of the related activities.

(b) Recovered over the remaining life of the original issue, which may range up to 50 years .

(c) Recorded as earned by employees and recovered as paid, generally within one year . This includes both vacation and banked holiday pay.

(d) Recorded and recovered or amortized as approved or accepted by the Alabama PSC over periods not exceeding 10 years . See Note 3 under "Retail Regulatory Matters" for additional information.

(e) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed three and a half years . Upon final settlement, actual costs incurred are recovered through the energy cost recovery clause.

(f) Comprised of components including generation site selection/evaluation costs, PPA capacity (to be recovered over the next 12 months ), and other miscellaneous assets. Recorded as accepted by the Alabama PSC. Capitalized upon initialization of related construction projects, if applicable.

(g) Comprised of components including mine reclamation and remediation liabilities and fuel-hedging gains. Recorded as accepted by the Alabama PSC. Mine reclamation and remediation liabilities will be settled following completion of the related activities.

(h) Utilized as storm restoration and potential reliability-related expenses are incurred, as approved by the Alabama PSC.

(i) Recovered and amortized over the average remaining service period which may range up to 15 years . See Note 2 for additional information.

(j) Not earning a return as offset in rate base by a corresponding asset or liability.

(k) Included in the deferred income tax charges are $13 million for 2017 and $16 million for 2016 for the retiree Medicare drug subsidy, which is recovered and amortized, as approved by the Alabama PSC, over the average remaining service period which may range up to 15 years .

(l) Recorded and amortized as approved by the Alabama PSC for a period up to 11 years .

(m) Established per an order from the Alabama PSC issued on February 17, 2017 and will be amortized concurrently with the effective date of the Company's next depreciation study. See Note 3 under "Retail Regulatory Matters – Rate RSE" for additional information.

(n) As a result of the Tax Reform Legislation, these accounts include certain deferred income tax assets and liabilities not subject to normalization. The recovery and amortization of these amounts will be established consistent with guidance provided by the Alabama PSC. See Note 5 for additional information.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated OCI related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" for additional information.

**Revenues**

Wholesale capacity revenues from PPAs are recognized either on a levelized basis over the appropriate contract period or the amount billable under the contract terms. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company and the Alabama PSC continuously monitor the under/over recovered balances. The Company files for revised rates as required or when management deems appropriate, depending on the rate. See Note 3 under "Retail Regulatory Matters – Rate ECR" and "Retail Regulatory Matters – Rate CNP Compliance" for additional information.

The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

**Fuel Costs**

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel.

**Income and Other Taxes**

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Federal ITCs utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

The Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

**Property, Plant, and Equipment**

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and cost of equity funds used during construction.

The Company's property, plant, and equipment in service consisted of the following at December 31:

| | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| Generation | **$ 14,213** | $ 13,551 |
| Transmission | **4,119** | 3,921 |
| Distribution | **7,034** | 6,707 |
| General | **1,948** | 1,840 |
| Plant acquisition adjustment | **12** | 12 |
| Total plant in service | **$ 27,326** | $ 26,031 |

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred or performed with the exception of nuclear refueling costs, which are recorded in accordance with specific Alabama PSC orders.

**Nuclear Outage Accounting Order**

In accordance with an Alabama PSC order, nuclear outage operations and maintenance expenses for the two units at Plant Farley are deferred to a regulatory asset when the charges actually occur and are then amortized over a subsequent 18 -month period with the fall outage costs amortization beginning in January of the following year and the spring outage costs amortization beginning in July of the same year.

**Depreciation and Amortization**

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 2.9% in 2017 , 3% in 2016 , and 2.9% in 2015 . Depreciation studies are conducted periodically to update the composite rates and the information is provided to the Alabama PSC and approved by the FERC. When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

In 2016, the Company submitted an updated depreciation study to the FERC and received authorization to use the recommended rates beginning January 2017. The study was also provided to the Alabama PSC.

**Asset Retirement Obligations and Other Costs of Removal**

AROs are computed as the present value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities. The Company has received accounting guidance from the Alabama PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The liability for AROs primarily relates to the decommissioning of the Company's nuclear facility, Plant Farley, and facilities that are subject to the Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA in 2015 (CCR Rule), principally ash ponds. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, asbestos removal related to ongoing repair and maintenance, disposal of polychlorinated biphenyls in certain transformers, and disposal of sulfur hexafluoride gas in certain substation breakers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, asbestos containing material within long-term assets not subject to ongoing repair and maintenance activities, and certain wireless communication towers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Alabama PSC, and are reflected in the balance sheets. See "Nuclear Decommissioning" herein for additional information on amounts included in rates.

Details of the AROs included in the balance sheets are as follows:

| | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| Balance at beginning of year | **$ 1,533** | $ 1,448 |
| Liabilities incurred | **—** | 5 |
| Liabilities settled | **(26)** | (25) |
| Accretion | **77** | 73 |
| Cash flow revisions | **125** | 32 |
| Balance at end of year | **$ 1,709** | $ 1,533 |

The increase in liabilities incurred and cash flow revisions in 2017 is primarily due to updated cost estimates related to the closure of ash ponds and landfills. The increase in 2016 is primarily related to changes in ash pond closure strategy.

The cost estimates for AROs related to the CCR Rule are based on information as of December 31, 2017 using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure in place. As further analysis is performed and closure details are developed, the Company will continue to periodically update these cost estimates as necessary.

**Nuclear Decommissioning**

The NRC requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and the Alabama PSC, as well as the IRS. While the Company is allowed to prescribe an overall investment policy to the Funds' managers, the Company and its affiliates are not allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of the Company. The Funds' managers are authorized, within certain investment guidelines, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

The Company records the investment securities held in the Funds at fair value, as disclosed in Note 10, as management believes that fair value best represents the nature of the Funds. Gains and losses, whether realized or unrealized, are recorded in the regulatory liability for AROs in the balance sheets and are not included in net income or OCI. Fair value adjustments and realized gains and losses are determined on a specific identification basis.

At December 31, 2017 , investment securities in the Funds totaled $902 million , consisting of equity securities of $644 million , debt securities of $223 million , and $35 million of other securities. At December 31, 2016 , investment securities in the Funds totaled $790 million , consisting of equity securities of $552 million , debt securities of $208 million , and $30 million of other securities. These amounts exclude receivables related to investment income and pending investment sales and payables related to pending investment purchases.

Sales of the securities held in the Funds resulted in cash proceeds of $237 million , $351 million , and $438 million in 2017 , 2016 , and 2015 , respectively, all of which were reinvested. For 2017 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $125 million , which included $98 million related to unrealized gains on securities held in the Funds at December 31, 2017 . For 2016 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $76 million , which included $34 million related to unrealized gains on securities held in the Funds at December 31, 2016 . For 2015 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $8 million , which included $57 million related to unrealized losses on securities held in the Funds at December 31, 2015 . While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of the securities and purpose for which the securities were acquired.

Amounts previously recorded in internal reserves are being transferred into the Funds through 2040 as approved by the Alabama PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed a plan with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

At December 31, the accumulated provisions for decommissioning were as follows:

| | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| External trust funds | **$ 902** | $ 790 |
| Internal reserves | **18** | 19 |
| Total | **$ 920** | $ 809 |

Site study cost is the estimate to decommission a facility as of the site study year. The estimated costs of decommissioning as of December 31, 2017 based on the most current study performed in 2013 for Plant Farley are as follows:

| | |
|---|---|
| Decommissioning periods: | |
| Beginning year | 2037 |
| Completion year | 2076 |
| | *(in millions)* |
| Site study costs: | |
| Radiated structures | $ 1,362 |
| Non-radiated structures | 80 |
| Total site study costs | $ 1,442 |

The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from the above estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates.

For ratemaking purposes, the Company's decommissioning costs are based on the site study. Significant assumptions used to determine these costs for ratemaking were an inflation rate of 4.5% and a trust earnings rate of 7.0% . The next site study is expected to be completed in 2018.

Amounts previously contributed to the Funds are currently projected to be adequate to meet the decommissioning obligations. The Company will continue to provide site-specific estimates of the decommissioning costs and related projections of funds in the external trust to the Alabama PSC and, if necessary, would seek the Alabama PSC's approval to address any changes in a manner consistent with NRC and other applicable requirements.

**Allowance for Funds Used During Construction**

The Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently, AFUDC increases the revenue requirement and is recovered over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. All current construction costs are included in retail rates. The AFUDC composite rate as of December 31 was 8.3% in 2017 , 8.4% in 2016 , and 8.7% in 2015 . AFUDC, net of income taxes, as a percentage of net income after dividends on preferred and preference stock was 5.7% in 2017 , 4.2% in 2016 , and 9.3% in 2015 .

**Impairment of Long-Lived Assets and Intangibles**

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

**Cash and Cash Equivalents**

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

**Materials and Supplies**

Generally, materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

**Fuel Inventory**

Fuel inventory includes the average cost of coal, natural gas, oil, transportation, and emissions allowances. Fuel is recorded to inventory when purchased and then expensed, at weighted average cost, as used and recovered by the Company through energy cost recovery rates approved by the Alabama PSC. Emissions allowances granted by the EPA are included in inventory at zero cost.

**Financial Instruments**

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities on the balance sheets (included in "Other") and are measured at fair value. See Note 10 for additional information regarding fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the Alabama PSC-approved fuel-hedging program result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded on a net basis in the statements of income. Cash flows from derivatives are classified on the statement of cash flows in the same category as the hedged item. See Note 11 for additional information regarding derivatives.

The Company offsets fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2017 .

The Company is exposed to potential losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

**Comprehensive Income**

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts included in net income.

**Variable Interest Entities**

The primary beneficiary of a VIE is required to consolidate the VIE when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE.

The Company has established a wholly-owned trust to issue preferred securities. See Note 6 under "Long-Term Debt Payable to an Affiliated Trust" for additional information. However, the Company is not considered the primary beneficiary of the trust. Therefore, the investment in the trust is reflected as other investments, and the related loan from the trust is reflected as long-term debt in the balance sheets.

## 2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2017 and no mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2018 . The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the Alabama PSC and the FERC. For the year ending December 31, 2018 , no other postretirement trusts contributions are expected.

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**Actuarial Assumptions**

The weighted average rates assumed in the actuarial calculations used to determine both the net periodic costs for the pension and other postretirement benefit plans for the following year and the benefit obligations as of the measurement date are presented below.

| Assumptions used to determine net periodic costs: | 2017 | 2016 | 2015 |
|---|---|---|---|
| **Pension plans** | | | |
| Discount rate – benefit obligations | **4.44%** | 4.67% | 4.18% |
| Discount rate – interest costs | **3.76** | 3.90 | 4.18 |
| Discount rate – service costs | **4.85** | 5.07 | 4.49 |
| Expected long-term return on plan assets | **7.95** | 8.20 | 8.20 |
| Annual salary increase | **4.46** | 4.46 | 3.59 |
| **Other postretirement benefit plans** | | | |
| Discount rate – benefit obligations | **4.27%** | 4.51% | 4.04% |
| Discount rate – interest costs | **3.58** | 3.69 | 4.04 |
| Discount rate – service costs | **4.70** | 4.96 | 4.40 |
| Expected long-term return on plan assets | **6.83** | 6.83 | 7.17 |
| Annual salary increase | **4.46** | 4.46 | 3.59 |

| Assumptions used to determine benefit obligations: | 2017 | 2016 |
|---|---|---|
| **Pension plans** | | |
| Discount rate | **3.81%** | 4.44% |
| Annual salary increase | **4.46** | 4.46 |
| **Other postretirement benefit plans** | | |
| Discount rate | **3.71%** | 4.27% |
| Annual salary increase | **4.46** | 4.46 |

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of eight different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2017 were as follows:

| | Initial Cost Trend Rate | Ultimate Cost Trend Rate | Year That Ultimate Rate is Reached |
|---|---|---|---|
| Pre-65 | 6.50% | 4.50% | 2026 |
| Post-65 medical | 5.00 | 4.50 | 2026 |
| Post-65 prescription | 10.00 | 4.50 | 2026 |

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An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2017 as follows:

| | 1 Percent Increase | 1 Percent Decrease |
|---|---|---|
| | *(in millions)* | |
| Benefit obligation | $ 30 | $ 26 |
| Service and interest costs | 1 | 1 |

**Pension Plans**

The total accumulated benefit obligation for the pension plans was $2.7 billion at December 31, 2017 and $2.4 billion at December 31, 2016 . Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2017 and 2016 were as follows:

| | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Change in benefit obligation** | | |
| Benefit obligation at beginning of year | **$ 2,663** | $ 2,506 |
| Service cost | **63** | 57 |
| Interest cost | **98** | 95 |
| Benefits paid | **(120)** | (109) |
| Actuarial (gain) loss | **294** | 114 |
| Balance at end of year | **2,998** | 2,663 |
| **Change in plan assets** | | |
| Fair value of plan assets at beginning of year | **2,517** | 2,279 |
| Actual return (loss) on plan assets | **427** | 206 |
| Employer contributions | **12** | 141 |
| Benefits paid | **(120)** | (109) |
| Fair value of plan assets at end of year | **2,836** | 2,517 |
| Accrued liability | **$ (162)** | $ (146) |

At December 31, 2017 , the projected benefit obligations for the qualified and non-qualified pension plans were $2.9 billion and $126 million , respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2017 and 2016 related to the Company's pension plans consist of the following:

| | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| Other regulatory assets, deferred | **$ 890** | $ 870 |
| Other current liabilities | **(12)** | (12) |
| Employee benefit obligations | **(150)** | (134) |

Presented below are the amounts included in regulatory assets at December 31, 2017 and 2016 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2018 .

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| | 2017 | 2016 | Estimated Amortization in 2018 |
|---|---|---|---|
| | | *(in millions)* | |
| Prior service cost | **$ 8** | $ 10 | **$ 1** |
| Net (gain) loss | **882** | 860 | **54** |
| Regulatory assets | **$ 890** | $ 870 | |

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2017 and 2016 are presented in the following table:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Regulatory assets:** | | |
| Beginning balance | **$ 870** | $ 822 |
| Net (gain) loss | **64** | 84 |
| Change in prior service costs | **—** | 7 |
| Reclassification adjustments: | | |
| Amortization of prior service costs | **(2)** | (3) |
| Amortization of net gain (loss) | **(42)** | (40) |
| Total reclassification adjustments | **(44)** | (43) |
| Total change | **20** | 48 |
| Ending balance | **$ 890** | $ 870 |

Components of net periodic pension cost were as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| Service cost | **$ 63** | $ 57 | $ 59 |
| Interest cost | **98** | 95 | 106 |
| Expected return on plan assets | **(196)** | (184) | (178) |
| Recognized net (gain) loss | **42** | 40 | 55 |
| Net amortization | **2** | 3 | 6 |
| Net periodic pension cost | **$ 9** | $ 11 | $ 48 |

Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

**NOTES (continued)**
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Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2017 , estimated benefit payments were as follows:

| | Benefit Payments |
|---|---|
| | *(in millions)* |
| 2018 | $ 129 |
| 2019 | 134 |
| 2020 | 139 |
| 2021 | 143 |
| 2022 | 148 |
| 2023 to 2027 | 807 |

**Other Postretirement Benefits**

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2017 and 2016 were as follows:

| | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Change in benefit obligation** | | |
| Benefit obligation at beginning of year | **$ 501** | $ 505 |
| Service cost | **6** | 5 |
| Interest cost | **17** | 18 |
| Benefits paid | **(29)** | (28) |
| Actuarial (gain) loss | **20** | (1) |
| Retiree drug subsidy | **2** | 2 |
| Balance at end of year | **517** | 501 |
| **Change in plan assets** | | |
| Fair value of plan assets at beginning of year | **367** | 363 |
| Actual return (loss) on plan assets | **60** | 23 |
| Employer contributions | **6** | 7 |
| Benefits paid | **(27)** | (26) |
| Fair value of plan assets at end of year | **406** | 367 |
| Accrued liability | **$ (111)** | $ (134) |

Amounts recognized in the balance sheets at December 31, 2017 and 2016 related to the Company's other postretirement benefit plans consist of the following:

| | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| Other regulatory assets, deferred | **$ 63** | $ 86 |
| Other regulatory liabilities, deferred | **(7)** | (10) |
| Employee benefit obligations | **(111)** | (134) |

**NOTES (continued)**
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Presented below are the amounts included in net regulatory assets (liabilities) at December 31, 2017 and 2016 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2018 .

| | 2017 | 2016 | Estimated Amortization in 2018 |
|---|---|---|---|
| | | (in millions) | |
| Prior service cost | $ 11 | $ 15 | $ 4 |
| Net (gain) loss | 45 | 61 | 1 |
| Net regulatory assets | $ 56 | $ 76 | |

The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2017 and 2016 are presented in the following table:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| **Net regulatory assets (liabilities):** | | |
| Beginning balance | $ 76 | $ 82 |
| Net (gain) loss | (15) | — |
| Reclassification adjustments: | | |
| Amortization of prior service costs | (4) | (4) |
| Amortization of net gain (loss) | (1) | (2) |
| Total reclassification adjustments | (5) | (6) |
| Total change | (20) | (6) |
| Ending balance | $ 56 | $ 76 |

Components of the other postretirement benefit plans' net periodic cost were as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | (in millions) | |
| Service cost | $ 6 | $ 5 | $ 6 |
| Interest cost | 17 | 18 | 20 |
| Expected return on plan assets | (25) | (25) | (26) |
| Net amortization | 5 | 6 | 5 |
| Net periodic postretirement benefit cost | $ 3 | $ 4 | $ 5 |

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

| | Benefit Payments | Subsidy Receipts | Total |
|---|---|---|---|
| | | (in millions) | |
| 2018 | $ 31 | $ (2) | $ 29 |
| 2019 | 32 | (2) | 30 |
| 2020 | 33 | (3) | 30 |
| 2021 | 34 | (3) | 31 |
| 2022 | 35 | (3) | 32 |
| 2023 to 2027 | 173 | (14) | 159 |

**Benefit Plan Assets**

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended. The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2017 and 2016 , along with the targeted mix of assets for each plan, is presented below:

| | Target | **2017** | 2016 |
|---|---|---|---|
| **Pension plan assets:** | | | |
| Domestic equity | 26% | **31%** | 29% |
| International equity | 25 | **25** | 22 |
| Fixed income | 23 | **24** | 29 |
| Special situations | 3 | **1** | 2 |
| Real estate investments | 14 | **13** | 13 |
| Private equity | 9 | **6** | 5 |
| Total | 100% | **100%** | 100% |
| **Other postretirement benefit plan assets:** | | | |
| Domestic equity | 42% | **44%** | 44% |
| International equity | 22 | **22** | 20 |
| Domestic fixed income | 28 | **28** | 29 |
| Special situations | 1 | **—** | 1 |
| Real estate investments | 4 | **4** | 4 |
| Private equity | 3 | **2** | 2 |
| Total | 100% | **100%** | 100% |

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns and interest rates, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices. Management believes the portfolio is well-diversified with no significant concentrations of risk.

***Investment Strategies***

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Trust-owned life insurance (TOLI).*** Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.

- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

***Benefit Plan Asset Fair Values***

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2017 and 2016 . The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- ***Domestic and international equity.*** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- ***Fixed income.*** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- ***TOLI.*** Investments in TOLI policies are classified as Level 2 investments and are valued based on the underlying investments held in the policy's separate account. The underlying assets are equity and fixed income pooled funds that are comprised of Level 1 and Level 2 securities.
- ***Real estate investments, private equity, and special situations investments.*** Investments in real estate, private equity, and special situations are generally classified as Net Asset Value as a Practical Expedient, since the underlying assets typically do not have publicly available observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. Techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, discounted cash flow analysis, prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals. The fair value of partnerships is determined by aggregating the value of the underlying assets less liabilities.

**NOTES (continued)**
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The fair values of pension plan assets as of December 31, 2017 and 2016 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| **As of December 31, 2017:** | **Quoted Prices in Active Markets for Identical Assets (Level 1)** | **Significant Other Observable Inputs (Level 2)** | **Significant Unobservable Inputs (Level 3)** | **Net Asset Value as a Practical Expedient (NAV)** | **Total** |
| | | | *(in millions)* | | |
| Assets: | | | | | |
| Domestic equity (*) | $ 572 | $ 276 | $ — | $ — | $ 848 |
| International equity (*) | 370 | 333 | — | — | 703 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 200 | — | — | 200 |
| Mortgage- and asset-backed securities | — | 2 | — | — | 2 |
| Corporate bonds | — | 286 | — | — | 286 |
| Pooled funds | — | 155 | — | — | 155 |
| Cash equivalents and other | 51 | 3 | — | — | 54 |
| Real estate investments | 111 | — | — | 283 | 394 |
| Special situations | — | — | — | 43 | 43 |
| Private equity | — | — | — | 159 | 159 |
| Total | $ 1,104 | $ 1,255 | $ — | $ 485 | $ 2,844 |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

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| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| **As of December 31, 2016:** | **Quoted Prices in Active Markets for Identical Assets (Level 1)** | **Significant Other Observable Inputs (Level 2)** | **Significant Unobservable Inputs (Level 3)** | **Net Asset Value as a Practical Expedient (NAV)** | **Total** |
| | | | *(in millions)* | | |
| Assets: | | | | | |
| Domestic equity (*) | $ 477 | $ 220 | $ — | $ — | $ 697 |
| International equity (*) | 292 | 264 | — | — | 556 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 140 | — | — | 140 |
| Mortgage- and asset-backed securities | — | 3 | — | — | 3 |
| Corporate bonds | — | 235 | — | — | 235 |
| Pooled funds | — | 124 | — | — | 124 |
| Cash equivalents and other | 236 | 1 | — | — | 237 |
| Real estate investments | 74 | — | — | 274 | 348 |
| Special situations | — | — | — | 43 | 43 |
| Private equity | — | — | — | 130 | 130 |
| Total | $ 1,079 | $ 987 | $ — | $ 447 | $ 2,513 |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

The fair values of other postretirement benefit plan assets as of December 31, 2017 and 2016 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| **As of December 31, 2017:** | **Quoted Prices in Active Markets for Identical Assets (Level 1)** | **Significant Other Observable Inputs (Level 2)** | **Significant Unobservable Inputs (Level 3)** | **Net Asset Value as a Practical Expedient (NAV)** | **Total** |
| | | | *(in millions)* | | |
| Assets: | | | | | |
| Domestic equity (*) | $ 52 | $ 12 | $ — | $ — | $ 64 |
| International equity (*) | 16 | 14 | — | — | 30 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 11 | — | — | 11 |
| Corporate bonds | — | 12 | — | — | 12 |
| Pooled funds | — | 7 | — | — | 7 |
| Cash equivalents and other | 2 | — | — | — | 2 |
| Trust-owned life insurance | — | 253 | — | — | 253 |
| Real estate investments | 5 | — | — | 12 | 17 |
| Special situations | — | — | — | 2 | 2 |
| Private equity | — | — | — | 7 | 7 |
| Total | $ 75 | $ 309 | $ — | $ 21 | $ 405 |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

| As of December 31, 2016: | Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Net Asset Value as a Practical Expedient (NAV) | Total |
|---|---|---|---|---|---|
| | | | (in millions) | | |
| Assets: | | | | | |
| Domestic equity (*) | $ 51 | $ 10 | $ — | $ — | $ 61 |
| International equity (*) | 13 | 12 | — | — | 25 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 7 | — | — | 7 |
| Corporate bonds | — | 10 | — | — | 10 |
| Pooled funds | — | 5 | — | — | 5 |
| Cash equivalents and other | 14 | — | — | — | 14 |
| Trust-owned life insurance | — | 220 | — | — | 220 |
| Real estate investments | 4 | — | — | 12 | 16 |
| Special situations | — | — | — | 2 | 2 |
| Private equity | — | — | — | 6 | 6 |
| Total | $ 82 | $ 264 | $ — | $ 20 | $ 366 |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

**Employee Savings Plan**

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company matches a portion of the first 6% of employee base salary contributions. The maximum Company match is 5.1% of an employee's base salary. Total matching contributions made to the plan for 2017 , 2016 , and 2015 were $23 million , $23 million , and $22 million , respectively.

## 3. CONTINGENCIES AND REGULATORY MATTERS

**General Litigation Matters**

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as standards for air, water, land, and protection of other natural resources, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by $CO_2$ and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

**Environmental Matters**

***Environmental Remediation***

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up affected sites. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the estimated costs to clean up known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable and reasonably estimable.

**Nuclear Fuel Disposal Costs**

Acting through the DOE and pursuant to the Nuclear Waste Policy Act of 1982, the U.S. government entered into a contract with the Company that requires the DOE to dispose of spent nuclear fuel and high level radioactive waste generated at Plant Farley beginning no later than January 31, 1998. The DOE has yet to commence the performance of its contractual and statutory obligation to dispose of spent nuclear fuel. Consequently, the Company has pursued and continues to pursue legal remedies against the U.S. government for its partial breach of contract.

In 2014, the Court of Federal Claims entered a judgment in favor of the Company in its spent nuclear fuel lawsuit seeking damages for the period from January 1, 2005 through December 31, 2010. In 2015, the Company recovered approximately $26 million , which was applied to reduce the cost of service for the benefit of customers.

In 2014, the Company filed a lawsuit against the U.S. government for the costs of continuing to store spent nuclear fuel at Plant Farley for the period from January 1, 2011 through December 31, 2013. The damage period was subsequently extended to December 31, 2014. On October 10, 2017, the Company filed an additional lawsuit against the U.S. government in the Court of Federal Claims for the costs of continuing to store spent nuclear fuel at Plant Farley for the period from January 1, 2015 through December 31, 2017. Damages will continue to accumulate until the issue is resolved or storage is provided. No amounts have been recognized in the financial statements as of December 31, 2017 for any potential recoveries from the pending lawsuits. The final outcome of these matters cannot be determined at this time. However, the Company expects to credit any recovery back for the benefit of customers in accordance with direction from the Alabama PSC and, therefore, no material impact on the Company's net income is expected.

At Plant Farley, on-site dry spent fuel storage facilities are operational and can be expanded to accommodate spent fuel through the expected life of the plant.

**FERC Matters**

The Company has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies (including the Company) and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In 2015, the FERC issued an order finding that the traditional electric operating companies' (including the Company's) and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional electric operating companies (including the Company) and Southern Power filed a request for rehearing and filed their response with the FERC in 2015.

In December 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. On May 17, 2017, the FERC accepted the traditional electric operating companies' (including the Company's) and Southern Power's compliance filing accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

On October 25, 2017, the FERC issued an order in response to the traditional electric operating companies' (including the Company's) and Southern Power's June 29, 2017 triennial updated market power analysis. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show cause within 60 days why market-based rate authority should not be revoked in certain areas adjacent to the area presently under mitigation in accordance with the February 2, 2017 order or to provide a mitigation plan to further address market power concerns. On November 10, 2017, the traditional electric operating companies (including the Company) and Southern Power responded to the FERC and proposed to resolve matters by applying the alternative mitigation authorized by the February 2, 2017 order to the adjacent areas made the subject of the October 25, 2017 order.

The ultimate outcome of these matters cannot be determined at this time.

**Retail Regulatory Matters**

***Rate RSE***

The Alabama PSC has adopted Rate RSE that provides for periodic annual adjustments based upon the Company's projected weighted cost of equity (WCE) compared to an allowable range. Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Retail rates remain unchanged when the WCE ranges between 5.75% and 6.21% with an adjusting point of 5.98% and eligibility for a performance-based adder of seven basis points, or 0.07% , to the WCE adjusting point if the Company (i) has an "A" credit rating equivalent with at least one of the recognized rating agencies or (ii) is in the top one-third of a designated customer value benchmark survey. Rate RSE adjustments for any two -year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0% . If the Company's actual retail return is above the allowed WCE range, the excess will be refunded to customers unless otherwise directed by the Alabama PSC; however, there is no provision for additional customer billings should the actual retail return fall below the WCE range.

At December 31, 2016, the Company's retail return exceeded the allowed WCE range which resulted in the Company establishing a $73 million Rate RSE refund liability. In accordance with an Alabama PSC order issued on February 14, 2017, the Company applied the full amount of the refund to reduce the under recovered balance of Rate CNP PPA as discussed further below.

Effective in January 2017, Rate RSE increased 4.48% , or $245 million annually. At December 31, 2017, the Company's actual retail return was within the allowed WCE range. On December 1, 2017, the Company made its required annual Rate RSE submission to the Alabama PSC of projected data for calendar year 2018. Projected earnings were within the specified range; therefore, retail rates under Rate RSE remained unchanged for 2018.

In conjunction with Rate RSE, the Company has an established retail tariff that provides for an adjustment to customer billings to recognize the impact of a change in the statutory income tax rate. As a result of Tax Reform Legislation, the application of this tariff would reduce annual retail revenue by approximately $250 million over the remainder of 2018. The ultimate outcome of this matter cannot be determined at this time.

***Rate CNP PPA***

The Company's retail rates, approved by the Alabama PSC, provide for adjustments under Rate CNP to recognize the placing of new generating facilities into retail service. The Company may also recover retail costs associated with certificated PPAs under Rate CNP PPA. On March 7, 2017, the Alabama PSC issued a consent order that the Company leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2017 through March 31, 2018. No adjustment to Rate CNP PPA is expected in 2018. As of December 31, 2017 and 2016, the Company had an under recovered Rate CNP PPA balance of $12 million and $142 million , respectively, which is included in deferred under recovered regulatory clause revenues in the balance sheet.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, the Company eliminated the under recovered balance in Rate CNP PPA at December 31, 2016, which totaled approximately $142 million . As discussed herein under "Rate RSE," the Company utilized the full amount of its $73 million Rate RSE refund liability to reduce the amount of the Rate CNP PPA under recovery and reclassified the remaining $69 million to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of the Company's next depreciation study, which is expected to occur within the next two to four years . The Company's current depreciation study became effective January 1, 2017.

***Rate CNP Compliance***

Rate CNP Compliance allows for the recovery of the Company's retail costs associated with laws, regulations, and other such mandates directed at the utility industry involving the environment, security, reliability, safety, sustainability, or similar considerations impacting the Company's facilities or operations. Rate CNP Compliance is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Compliance costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. Revenues for Rate CNP Compliance, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. Changes in Rate CNP Compliance-related operations and maintenance expenses and depreciation generally will have no effect on net income.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, the Company reclassified $36 million of its under recovered balance in Rate CNP Compliance to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of the Company's next depreciation study, which is expected to occur within the next two to four years . The Company's current depreciation study became effective January 1, 2017.

On December 5, 2017, the Alabama PSC issued a consent order that the Company leave in effect for 2018 the factors associated with the Company's compliance costs for the year 2017, with any under-collected amount for prior years deemed recovered before any current year amounts. Any under recovered amounts associated with 2018 will be reflected in the 2019 filing. As of December 31, 2017 and 2016, the Company had a deferred under recovered regulatory clause revenues balance of $17 million and $9 million , respectively.

***Rate ECR***

The Company has established energy cost recovery rates under the Company's Rate ECR as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. The Company, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on the Company's net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per KWH.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, the Company reclassified $36 million of its under recovered balance in Rate ECR to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of the Company's next depreciation study, which is expected to occur within the next two to four years . The Company's current depreciation study became effective January 1, 2017.

On December 5, 2017, the Alabama PSC issued a consent order that the Company leave in effect for 2018 the energy cost recovery rates which began in 2017. Therefore, the Rate ECR factor as of January 1, 2018 remained at 2.015 cents per KWH. The rate will return to 5.910 cents per KWH in 2019, absent a further order from the Alabama PSC.

At December 31, 2017, the Company's under recovered fuel costs totaled $25 million , which is included in deferred under recovered regulatory clause revenues. At December 31, 2016, the Company had an over recovered fuel balance of $76 million , which was included in other regulatory liabilities, current. These classifications are based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any recovery or return of fuel costs.

***Rate NDR***

Based on an order from the Alabama PSC, the Company maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate NDR charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. When the reserve balance falls below $50 million , a reserve establishment charge will be activated (and the on-going reserve maintenance charge concurrently suspended) until the reserve balance reaches $75 million . The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24 -month period. The Alabama PSC order gives the Company authority to record a deficit balance in the NDR when costs of storm damage exceed any established reserve balance. Absent further Alabama PSC approval, the maximum total Rate NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account. The Company has the authority, based on an order from the Alabama PSC, to accrue certain additional amounts as circumstances warrant. The order allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million . The Company may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance the Company's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear. No such accruals were recorded or designated in any period presented.

In December 2017, the reserve maintenance charge was suspended and the reserve establishment charge was activated as a result of the NDR balance falling below $50 million . The Company expects to collect approximately $16 million annually until the reserve balance is restored to $75 million . The NDR balance at December 31, 2017 was $38 million .

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

***Environmental Accounting Order***

Based on an order from the Alabama PSC, the Company is allowed to establish a regulatory asset to record the unrecovered investment costs, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure associated with future unit retirements caused by environmental regulations. The regulatory asset will be amortized and recovered over the affected unit's remaining useful life, as established prior to the decision regarding early retirement through Rate CNP Compliance.

The Company retired Plant Gorgas Units 6 and 7 ( 200 MWs) and Plant Barry Unit 3 ( 225 MWs) in 2015. Additionally, the Company ceased using coal at Plant Barry Units 1 and 2 ( 250 MWs) in 2015, but such units remain available on a limited basis with natural gas as the fuel source. In April 2016, the Company also ceased using coal at Plant Greene County Units 1 and 2 ( 300 MWs representing the Company's ownership interest) and began operating Units 1 and 2 solely on natural gas in June 2016 and July 2016, respectively.

In accordance with this accounting order from the Alabama PSC, the Company transferred the unrecovered plant asset balances to regulatory assets at their respective retirement dates. These regulatory assets are being amortized and recovered through Rate CNP Compliance over the units' remaining useful lives, as established prior to the decision for retirement; therefore, these decisions associated with coal operations had no significant impact on the Company's financial statements.

## 4. JOINT OWNERSHIP AGREEMENTS

The Company and Georgia Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 MWs, as well as associated transmission facilities. SEGCO uses natural gas as the primary fuel source for 1,000 MWs of its generating capacity. The capacity of these units is sold equally to the Company and Georgia Power under a power contract. The Company and Georgia Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and ROE. The Company's share of purchased power totaled $76 million in 2017 , $55 million in 2016 , and $76 million in 2015 and is included in "Purchased power from affiliates" in the statements of income. The Company accounts for SEGCO using the equity method.

In addition, the Company has guaranteed unconditionally the obligation of SEGCO under an installment sale agreement for the purchase of certain pollution control facilities at SEGCO's generating units, pursuant to which $25 million principal amount of pollution control revenue bonds are outstanding. The Company has guaranteed $100 million principal amount of unsecured senior notes issued by SEGCO for general corporate purposes. These senior notes mature on December 1, 2018. Georgia Power has agreed to reimburse the Company for the pro rata portion of such obligations corresponding to its then proportionate ownership of stock of SEGCO if the Company is called upon to make such payment under its guarantee.

At December 31, 2017 , the capitalization of SEGCO consisted of $95 million of equity and $125 million of long-term debt on which the annual interest requirement is $4 million . In addition, SEGCO had short-term debt outstanding of $14 million . SEGCO paid $24 million of dividends in 2017 and 2016 compared to an immaterial amount in 2015 , of which one-half of each was paid to the Company. In addition, the Company recognizes 50% of SEGCO's net income.

The Company, which owns and operates a generating unit adjacent to the SEGCO generating units, has a joint ownership agreement with SEGCO for the ownership of an associated gas pipeline. The Company owns 14% of the pipeline with the remaining 86% owned by SEGCO.

In addition to the Company's ownership of SEGCO and joint ownership of an associated gas pipeline, the Company's percentage ownership and investment in jointly-owned generating plants at December 31, 2017 were as follows:

| Facility | Total MW Capacity | Company Ownership | Plant in Service | Accumulated Depreciation | Construction Work in Progress |
|---|---|---|---|---|---|
| | | | | *(in millions)* | |
| Greene County | 500 | 60.00% (1) | $ 172 | $ 65 | $ 2 |
| Plant Miller | | | | | |
| Units 1 and 2 | 1,320 | 91.84% (2) | 1,717 | 619 | 54 |

(1) Jointly owned with an affiliate, Mississippi Power.

(2) Jointly owned with PowerSouth Energy Cooperative, Inc.

The Company has contracted to operate and maintain its jointly-owned facilities as agent for their co-owners. The Company's proportionate share of its plant operating expenses is included in operating expenses in the statements of income and the Company is responsible for providing its own financing.

## 5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and various combined and separate state income tax returns. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

### Federal Tax Reform Legislation

Following the enactment of Tax Reform Legislation, the SEC staff issued Staff Accounting Bulletin 118 – "Income Tax Accounting Implications of the Tax Cuts and Jobs Act" (SAB 118), which provides for a measurement period of up to one year from the enactment date to complete accounting under GAAP for the tax effects of the legislation. Due to the complex and comprehensive nature of the enacted tax law changes, and their application under GAAP, the Company considers all amounts recorded in the financial statements as a result of Tax Reform Legislation to be "provisional" as discussed in SAB 118 and subject to revision. The Company is awaiting additional guidance from industry and income tax authorities in order to finalize its accounting. The ultimate impact of Tax Reform Legislation on deferred income tax assets and liabilities and the related regulatory assets and liabilities cannot be determined at this time. See Note 3 under "Retail Regulatory Matters – Rate RSE" for additional information.

### Current and Deferred Income Taxes

Details of income tax provisions are as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| Federal — | | | |
| Current | **$ 136** | $ 103 | $ 110 |
| Deferred | **336** | 339 | 320 |
| | **472** | 442 | 430 |
| State — | | | |
| Current | **23** | 20 | 8 |
| Deferred | **73** | 69 | 68 |
| | **96** | 89 | 76 |
| Total | **$ 568** | $ 531 | $ 506 |

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| Deferred tax liabilities — | | |
| Accelerated depreciation | **$ 2,336** | $ 4,307 |
| Property basis differences | **398** | 456 |
| Premium on reacquired debt | **16** | 26 |
| Employee benefit obligations | **162** | 201 |
| Regulatory assets associated with employee benefit obligations | **260** | 393 |
| Asset retirement obligations | **220** | 289 |
| Regulatory assets associated with asset retirement obligations | **249** | 347 |
| Other | **147** | 179 |
| Total | **3,788** | 6,198 |
| Deferred tax assets — | | |
| Federal effect of state deferred taxes | **143** | 266 |
| Unbilled fuel revenue | **22** | 36 |
| Storm reserve | **5** | 21 |
| Employee benefit obligations | **286** | 427 |
| Other comprehensive losses | **10** | 19 |
| Asset retirement obligations | **469** | 636 |
| Other | **93** | 139 |
| Total | **1,028** | 1,544 |
| Accumulated deferred income taxes, net | **$ 2,760** | $ 4,654 |

The implementation of Tax Reform Legislation significantly reduced accumulated deferred income taxes, partially offset by bonus depreciation provisions in the 2015 Protecting Americans from Tax Hikes Act. Tax Reform Legislation also significantly reduced tax-related regulatory assets and increased tax-related regulatory liabilities.

At December 31, 2017 , the tax-related regulatory assets to be recovered from customers were $240 million . These assets are primarily attributable to tax benefits flowed through to customers in prior years, deferred taxes previously recognized at rates lower than the current enacted tax law, and taxes applicable to capitalized interest.

At December 31, 2017 , the tax-related regulatory liabilities to be credited to customers were $2.1 billion . These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized ITCs.

In accordance with regulatory requirements, deferred federal ITCs are amortized over the average life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $7 million in 2017 and $8 million annually in 2016 and 2015. At December 31, 2017 , the Company had federal ITC carryforwards which are expected to result in $9 million of federal income tax benefits. The federal ITC carryforwards begin expiring in 2038 but are expected to be fully utilized by 2027. The ultimate outcome of these matters cannot be determined at this time.

**Tax Credit Carryforwards**

The Company had state credit carryforwards for the state of Alabama of approximately $4 million , which begin expiring in 2023 but are expected to be fully utilized.

**Effective Tax Rate**

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| Federal statutory rate | **35.0%** | 35.0% | 35.0% |
| State income tax, net of federal deduction | **4.4** | 4.2 | 3.8 |
| Non-deductible book depreciation | **0.9** | 1.0 | 1.2 |
| AFUDC equity | **(1.0)** | (0.7) | (1.6) |
| Tax Reform Legislation | **0.3** | — | — |
| Other | **—** | (0.7) | — |
| Effective income tax rate | **39.6%** | 38.8% | 38.4% |

In March 2016, the FASB issued ASU 2016-09, which changed the accounting for income taxes for share-based payment award transactions. Entities are required to recognize all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation as income tax expense or benefit in the income statement. The adoption of ASU 2016-09 did not have a material impact on the Company's overall effective tax rate. See Note 1 under " Recently Issued Accounting Standards " for additional information.

**Unrecognized Tax Benefits**

The Company has no material unrecognized tax benefits for the periods presented. The Company classifies interest on tax uncertainties as interest expense. Accrued interest for unrecognized tax benefits was immaterial and the Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months. The settlement of federal and state audits could impact the balances. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2016. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2011.

## 6. FINANCING

**Long-Term Debt Payable to an Affiliated Trust**

The Company has formed a wholly-owned trust subsidiary for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $206 million outstanding as of December 31, 2017 and 2016 , which constitute substantially all of the assets of this trust and are reflected in the balance sheets as long-term debt payable. The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the trust's payment obligations with respect to these securities. At December 31, 2017 and 2016 , trust preferred securities of $200 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for this trust and the related securities.

**Securities Due Within One Year**

At December 31, 2017 , the Company had no securities due within one year. At December 31, 2016 , the Company had $561 million of senior notes and pollution control revenue bonds due within one year.

Maturities through 2022 applicable to total long-term debt are as follows: $200 million in 2019 ; $250 million in 2020 ; $310 million in 2021 ; and $750 million in 2022 . There are no scheduled maturities in 2018 .

**Bank Term Loans**

At both December 31, 2017 and 2016 , the Company had $45 million of outstanding bank term loans agreements, which are reflected in the statements of capitalization as long-term debt.

These bank loans have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of calculating these covenants, any long-term notes payable to affiliated trusts are excluded from debt but included in capitalization. At December 31, 2017 , the Company was in compliance with its debt limits.

**Pollution Control Revenue Bonds**

Pollution control revenue bond obligations represent loans to the Company from public authorities of funds or installment purchases of pollution control and solid waste disposal facilities financed by funds derived from sales by public authorities of revenue bonds. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The Company incurred no obligations related to the issuance of pollution control revenue bonds in 2017.

In August 2017, the Company repaid at maturity $36.1 million aggregate principal amount of Series 1993-A, 1993-B, and 1993-C Industrial Development Board of the City of Mobile, Alabama Pollution Control Revenue Refunding Bonds (Alabama Power Company Project).

The Company had $1.06 billion and $1.10 billion of tax-exempt pollution control revenue bond obligations outstanding at December 31, 2017 and 2016 , respectively, including pollution control revenue bonds classified as due within one year.

**Senior Notes**

In March 2017, the Company issued $550 million aggregate principal amount of Series 2017A 2.45% Senior Notes due March 30, 2022. The proceeds were used to repay the Company's short-term indebtedness and for general corporate purposes, including the Company's continuous construction program.

In November 2017, the Company issued $550 million aggregate principal amount of Series 2017B 3.70% Senior Notes due December 1, 2047. The proceeds were used for general corporate purposes, including the Company's continuous construction program .

At December 31, 2017 and 2016 , the Company had $6.4 billion and $5.8 billion of senior notes outstanding, respectively, including senior notes classified as due within one year. At December 31, 2017 and 2016, the Company did not have any outstanding secured debt.

**Redeemable Preferred and Preference Stock**

The Company currently has preferred stock, Class A preferred stock, and common stock outstanding. The Company also has authorized preference stock, none of which is outstanding. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's common stock with respect to payment of dividends and voluntary and involuntary dissolution. The preferred stock and Class A preferred stock of the Company contain a feature that allows the holders to elect a majority of the Company's board of directors if preferred dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of the Company, the preferred stock and Class A preferred stock is presented as "Redeemable Preferred Stock" in a manner consistent with temporary equity under applicable accounting standards.

The Company's preferred stock is subject to redemption at a price equal to the par value plus a premium. The Company's Class A preferred stock is subject to redemption at a price equal to the stated capital. All series of the Company's preferred stock currently are subject to redemption at the option of the Company. The Class A preferred stock is subject to redemption on or after October 1, 2022, or following the occurrence of a rating agency event. Information for each outstanding series is in the table below:

| Preferred/Preference Stock | Par Value/Stated Capital Per Share | Shares Outstanding | Redemption Price Per Share |
|---|---|---|---|
| 4.92% Preferred Stock | $100 | 80,000 | $103.23 |
| 4.72% Preferred Stock | $100 | 50,000 | $102.18 |
| 4.64% Preferred Stock | $100 | 60,000 | $103.14 |
| 4.60% Preferred Stock | $100 | 100,000 | $104.20 |
| 4.52% Preferred Stock | $100 | 50,000 | $102.93 |
| 4.20% Preferred Stock | $100 | 135,115 | $105.00 |
| 5.00% Class A Preferred Stock | $25 | 10,000,000 | Stated Capital (*) |

(*) Prior to October 1, 2022: $25.50 ; on or after October 1, 2022: Stated Capital

In September 2017, the Company issued 10 million shares ( $250 million aggregate stated capital) of 5.00% Class A Preferred Stock, Cumulative, Par Value $1 Per Share (Stated Capital 25 Per Share). The proceeds were used in October 2017 to redeem all 2 million shares ( $50 million aggregate stated capital) of 6.50% Series Preference Stock, 6 million shares ( $150 million aggregate stated capital) of 6.45% Series Preference Stock, and 1.52 million shares ( $38 million aggregate stated capital) of 5.83% Class A Preferred Stock and for other general corporate purposes, including the Company's continuous construction program.

There were no changes for the year ended December 31, 2016 in redeemable preferred stock or preference stock of the Company.

**Dividend Restrictions**

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

**Bank Credit Arrangements**

At December 31, 2017 , committed credit arrangements with banks were as follows:

| Expires | | | | | Expires Within One Year | |
|---|---|---|---|---|---|---|
| 2018 | 2020 | 2022 | Total | Unused | Term Out | No Term Out |
| (in millions) | | | (in millions) | | (in millions) | |
| $ 35 | $ 500 | $ 800 | $ 1,335 | $ 1,335 | $ — | $ 35 |

Most of the bank credit arrangements require payment of a commitment fee based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees average less than $^1/_4$ of 1% for the Company. Compensating balances are not legally restricted from withdrawal.

Subject to applicable market conditions, the Company expects to renew or replace its bank credit agreements as needed, prior to expiration. In connection therewith, the Company may extend the maturity date and/or increase or decrease the lending commitments thereunder.

Most of the Company's bank credit arrangements contain covenants that limit the Company's debt level to 65% of total capitalization, as defined in the arrangements. For purposes of calculating these covenants, any long-term notes payable to affiliated trusts are excluded from debt but included in capitalization. At December 31, 2017 , the Company was in compliance with the debt limit covenants.

A portion of the unused credit with banks is allocated to provide liquidity support to the Company's pollution control revenue bonds and commercial paper programs. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support was $854 million as of December 31, 2017 . In addition, at December 31, 2017, the Company had $120 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

The Company borrows through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above. The Company may also make short-term borrowings through various other arrangements with banks. At December 31, 2017 , the Company had $3 million in short-term debt outstanding and none at December 31, 2016 . At December 31, 2017 , the Company had regulatory approval to have outstanding up to $2.0 billion of short-term borrowings.

## 7. COMMITMENTS

### Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil and nuclear fuel which are not recognized on the balance sheets. In 2017, 2016, and 2015, the Company incurred fuel expense of $1.2 billion , $1.3 billion , and $1.3 billion , respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

In addition, the Company has entered into various long-term commitments for the purchase of capacity and electricity, some of which are accounted for as operating leases. Total capacity expense under PPAs accounted for as operating leases was $41 million , $42 million , and $38 million for 2017, 2016, and 2015, respectively. Total estimated minimum long-term obligations at December 31, 2017 were as follows:

| | Operating Lease PPAs |
|---|---|
| | *(in millions)* |
| 2018 | $ 41 |
| 2019 | 43 |
| 2020 | 44 |
| 2021 | 46 |
| 2022 | 47 |
| 2023 and thereafter | — |
| Total commitments | $ 221 |

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other traditional electric operating companies and Southern Power. Under these agreements, each of the traditional electric operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional electric operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

### Operating Leases

The Company has entered into operating leases with Southern Linc and third parties for the use of cellular tower space. Substantially all of these agreements have initial terms ranging from five to 10 years and renewal options of up to 20 years . The Company has entered into rental agreements for towers, coal railcars, vehicles, and other equipment with various terms and expiration dates. Total rent expense under these agreements was $25 million in 2017 , $18 million in 2016 , and $19 million in 2015 . Of these amounts, $11 million , $14 million , and $13 million for 2017, 2016, and 2015, respectively, relate to the railcar leases and was recovered through the Company's Rate ECR. The Company includes any step rents, fixed escalations, and lease concessions in its computation of minimum lease payments.

**NOTES (continued)**
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As of December 31, 2017 , estimated minimum lease payments under operating leases were as follows:

| | Minimum Lease Payments [(a)] | | | |
|---|---|---|---|---|
| | Affiliate Operating Leases [(b)] | Railcars | Vehicles & Other | Total |
| | | *(in millions)* | | |
| 2018 | $ 8 | $ 7 | $ 6 | $ 21 |
| 2019 | 10 | 7 | 5 | 22 |
| 2020 | 8 | 7 | 3 | 18 |
| 2021 | 7 | 6 | 1 | 14 |
| 2022 | 5 | 5 | — | 10 |
| 2023 and thereafter | 16 | 4 | — | 20 |
| Total | $ 54 | $ 36 | $ 15 | $ 105 |

(a) Minimum lease payments have not been reduced by minimum sublease rentals of $3 million in the future.

(b) Includes operating leases for cellular tower space.

In addition to the above rental commitments payments, the Company has potential obligations upon expiration of certain railcar leases with respect to the residual value of the leased property. These leases have terms expiring through 2023 with maximum obligations under these leases of $12 million in 2023. There are no obligations under these leases through 2022. At the termination of the leases, the lessee may either exercise its purchase option, or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligations.

### Guarantees

The Company has guaranteed the obligation of SEGCO for $25 million of pollution control revenue bonds issued in 2001, which mature in June 2019, and also $100 million of senior notes issued in 2013, which mature in December 2018. Georgia Power has agreed to reimburse the Company for the pro rata portion of such obligations corresponding to Georgia Power's then proportionate ownership of SEGCO's stock if the Company is called upon to make such payment under its guarantee. See Note 4 for additional information.

## 8. STOCK COMPENSATION

### Stock-Based Compensation

Stock-based compensation primarily in the form of Southern Company performance share units and restricted stock units may be granted through the Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. In 2015 and 2016, stock-based compensation consisted exclusively of performance share units. Beginning in 2017, stock-based compensation granted to employees includes restricted stock units in addition to performance share units. Prior to 2015, stock-based compensation also included stock options. As of December 31, 2017 , there were 793 current and former employees participating in the stock option, performance share unit, and restricted stock unit programs.

#### *Performance Share Units*

Performance share units granted to employees vest at the end of a three -year performance period. All unvested performance share units vest immediately upon a change in control where Southern Company is not the surviving corporation. Shares of Southern Company common stock are delivered to employees at the end of the performance period with the number of shares issued ranging from 0% to 200% of the target number of performance share units granted, based on achievement of the performance goals established by the Compensation Committee of the Southern Company Board of Directors.

Southern Company issues performance share units with performance goals based on three performance goals to employees. These include performance share units with performance goals based on the total shareholder return (TSR) for Southern Company common stock during the three -year performance period as compared to a group of industry peers, performance share units with performance goals based on Southern Company's cumulative earnings per share (EPS) over the performance period, and performance share units with performance goals based on Southern Company's equity-weighted ROE over the performance period.

In 2015 and 2016, the EPS-based and ROE-based awards each represented 25% of the total target grant date fair value of the performance share unit awards granted. The remaining 50% of the total target grant date fair value consisted of TSR-based awards. Beginning in 2017, the total target grant date fair value of the stock compensation awards granted was comprised 20% each of EPS-based awards and ROE-based awards and 30% each of TSR-based awards and restricted stock units.

The fair value of TSR-based performance share unit awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's common stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three -year performance period without remeasurement.

The fair values of the EPS-based awards and the ROE-based awards are based on the closing stock price of Southern Company common stock on the date of the grant. Compensation expense for the EPS-based and ROE-based awards is generally recognized ratably over the three -year performance period initially assuming a 100% payout at the end of the performance period. Employees become immediately vested in the TSR-based performance share units, along with the EPS-based and ROE-based awards, upon retirement. As a result, compensation expense for employees that are retirement eligible at the grant date is recognized immediately while compensation expense for employees that become retirement eligible during the vesting period is recognized over the period from grant date to the date of retirement eligibility. The expected payout related to the EPS-based and ROE-based awards is reevaluated annually with expense recognized to date increased or decreased based on the number of shares currently expected to be issued. Unlike the TSR-based awards, the compensation expense ultimately recognized for the EPS-based awards and the ROE-based awards will be based on the actual number of shares issued at the end of the performance period.

For the years ended December 31, 2017 , 2016 , and 2015, employees of the Company were granted performance share units of 135,502 , 249,065 , and 214,709 , respectively. The weighted average grant-date fair value of TSR-based performance share units granted during 2017, 2016, and 2015, determined using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period, was $49.07 , $45.15 , and $46.42 , respectively. The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2017, 2016, and 2015 was $49.21 , $48.86 , and $47.78 , respectively.

For the years ended December 31, 2017 , 2016 , and 2015, total compensation cost for performance share units recognized in income was $9 million , $15 million , and $13 million , respectively, with the related tax benefit also recognized in income of $4 million , $6 million , and $5 million , respectively. The compensation cost related to the grant of Southern Company performance share units to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2017 , $2 million of total unrecognized compensation cost related to performance share award units will be recognized over a weighted-average period of approximately 21 months .

***Restricted Stock Units***

Beginning in 2017, stock-based compensation granted to employees included restricted stock units in addition to performance share units. One-third of the restricted stock units granted to employees vest each year throughout a three -year service period. All unvested restricted stock units vest immediately upon a change in control where Southern Company is not the surviving corporation. Shares of Southern Company common stock are delivered to employees at the end of the vesting period.

The fair value of restricted stock units is based on the closing stock price of Southern Company common stock on the date of the grant. Since one-third of the restricted stock units vest each year throughout a three -year service period, compensation expense for restricted stock unit awards is generally recognized over the corresponding one -, two -, or three-year period. Employees become immediately vested in the restricted stock units upon retirement. As a result, compensation expense for employees that are retirement eligible at the grant date is recognized immediately while compensation expense for employees that become retirement eligible during the vesting period is recognized over the period from grant date to the date of retirement eligibility.

For the year ended December 31, 2017 , employees of the Company were granted 58,001 restricted stock units. The weighted average grant-date fair value of restricted stock units granted during 2017 was $49.21 .

For the year ended December 31, 2017 , total compensation cost for restricted stock units recognized in income was $3 million with the related tax benefit also recognized in income of $1 million . As of December 31, 2017 , total unrecognized compensation cost related to restricted stock units was immaterial.

***Stock Options***

In 2015, Southern Company discontinued the granting of stock options. Stock options expire no later than 10 years after the grant date and the latest possible exercise will occur no later than November 2024.

The compensation cost related to the grant of Southern Company stock options to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. Compensation cost and related tax benefits recognized in the Company's financial statements were not material for any year presented. As of December 31, 2017 , all compensation cost related to stock option awards has been recognized.
The total intrinsic value of options exercised during the years ended December 31, 2017 , 2016 , and 2015 was $12 million , $21 million , and $8 million , respectively. No cash proceeds are received by the Company upon the exercise of stock options. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $5 million , $8 million , and $3 million for the years ended December 31, 2017 , 2016 , and 2015 , respectively. Prior to the adoption of ASU 2016-09 in 2016 , the excess tax benefits related to the exercise of stock options were recognized in the Company's financial statements with a credit to equity. Upon the adoption of ASU 2016-09, beginning in 2016, all tax benefits related to the exercise of stock options are recognized in income. As of December 31, 2017 , the aggregate intrinsic value for the options outstanding and exercisable was $17 million .

## 9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Plant Farley. The Act provides funds up to $13.4 billion for public liability claims that could arise from a single nuclear incident. Plant Farley is insured against this liability to a maximum of $450 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. The Company could be assessed up to $127 million per incident for each licensed reactor it operates but not more than an aggregate of $19 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company is $255 million per incident but not more than an aggregate of $38 million to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years . The next scheduled adjustment is due no later than September 10, 2018.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $1.5 billion for members' operating nuclear generating facilities. Additionally, the Company has NEIL policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $1.25 billion for nuclear losses and policies providing coverage up to $750 million for non-nuclear losses in excess of the $1.5 billion primary coverage.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks , with a maximum per occurrence per unit limit of $490 million . After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted. The Company purchases limits based on the projected full cost of replacement power and has elected a 12-week deductible waiting period.

Under each of the NEIL policies, members are subject to assessments each year if losses exceed the accumulated funds available to the insurer. The maximum annual assessments for the Company as of December 31, 2017 under the NEIL policies would be $55 million .

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by the Company and could have a material effect on the Company's financial condition and results of operations.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

## 10. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 2017 , assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| **As of December 31, 2017:** | **Quoted Prices in Active Markets for Identical Assets (Level 1)** | **Significant Other Observable Inputs (Level 2)** | **Significant Unobservable Inputs (Level 3)** | **Net Asset Value as a Practical Expedient (NAV)** | **Total** |
| | | | *(in millions)* | | |
| Assets: | | | | | |
| Energy-related derivatives | $ — | $ 4 | $ — | $ — | $ 4 |
| Nuclear decommissioning trusts: (*) | | | | | |
| Domestic equity | 442 | 81 | — | — | 523 |
| Foreign equity | 62 | 59 | — | — | 121 |
| U.S. Treasury and government agency securities | — | 24 | — | — | 24 |
| Corporate bonds | 21 | 160 | — | — | 181 |
| Mortgage and asset backed securities | — | 18 | — | — | 18 |
| Private equity | — | — | — | 29 | 29 |
| Other | 6 | — | — | — | 6 |
| Cash equivalents | 349 | — | — | — | 349 |
| Total | $ 880 | $ 346 | $ — | $ 29 | $ 1,255 |
| Liabilities: | | | | | |
| Energy-related derivatives | $ — | $ 10 | $ — | $ — | $ 10 |

(*) Excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases. See Note 1 under "Nuclear Decommissioning" for additional information.

**NOTES (continued)**
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As of December 31, 2016 , assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| **As of December 31, 2016:** | **Quoted Prices in Active Markets for Identical Assets (Level 1)** | **Significant Other Observable Inputs (Level 2)** | **Significant Unobservable Inputs (Level 3)** | **Net Asset Value as a Practical Expedient (NAV)** | **Total** |
| | | | *(in millions)* | | |
| Assets: | | | | | |
| Energy-related derivatives | $ — | $ 20 | $ — | $ — | $ 20 |
| Nuclear decommissioning trusts: (*) | | | | | |
| Domestic equity | 385 | 72 | — | — | 457 |
| Foreign equity | 48 | 47 | — | — | 95 |
| U.S. Treasury and government agency securities | — | 21 | — | — | 21 |
| Corporate bonds | 22 | 146 | — | — | 168 |
| Mortgage and asset backed securities | — | 19 | — | — | 19 |
| Private equity | — | — | — | 20 | 20 |
| Other | — | 10 | — | — | 10 |
| Cash equivalents | 262 | — | — | — | 262 |
| Total | $ 717 | $ 335 | $ — | $ 20 | $ 1,072 |
| Liabilities: | | | | | |
| Energy-related derivatives | $ — | $ 9 | $ — | $ — | $ 9 |

(*) Excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases. See Note 1 under "Nuclear Decommissioning" for additional information.

**Valuation Methodologies**

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard over-the-counter products that are valued using observable market data and assumptions commonly used by market participants. The fair value of interest rate derivatives reflects the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk, and occasionally, implied volatility of interest rate options. The interest rate derivatives are categorized as Level 2 under Fair Value Measurements as these inputs are based on observable data and valuations of similar instruments. See Note 11 for additional information on how these derivatives are used.

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. For fair value measurements of the investments within the nuclear decommissioning trusts, external pricing vendors are designated for each asset class with each security specifically assigned a primary pricing source. For investments held within commingled funds, fair value is determined at the end of each business day through the net asset value, which is established by obtaining the underlying securities' individual prices from the primary pricing source. See Note 1 under "Nuclear Decommissioning" for additional information. A market price secured from the primary source vendor is then evaluated by management in its valuation of the assets within the trusts. As a general approach, fixed income market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information, including live trading levels and pricing analysts' judgments, are also obtained when available.

As of December 31, 2017 and 2016 , the fair value measurements of private equity investments held in the nuclear decommissioning trusts that are calculated at net asset value per share (or its equivalent) as a practical expedient, as well as the nature and risks of those investments, were as follows:

| | Fair Value | Unfunded Commitments | Redemption Frequency | Redemption Notice Period |
|---|---|---|---|---|
| | *(in millions)* | | | |
| **As of December 31, 2017** | **$ 29** | **$ 21** | **Not Applicable** | **Not Applicable** |
| As of December 31, 2016 | $ 20 | $ 25 | Not Applicable | Not Applicable |

Private equity funds include a fund-of-funds that invests in high quality private equity funds across several market sectors, funds that invest in real estate assets, and a fund that acquires companies to create resale value. Private equity funds do not have redemption rights. Distributions from these funds will be received as the underlying investments in the funds are liquidated. Liquidations of these investments are expected to occur at various times over the next 10 years .

As of December 31, 2017 and 2016 , other financial instruments for which the carrying amount did not equal fair value were as follows:

| | Carrying Amount | Fair Value |
|---|---|---|
| | *(in millions)* | |
| Long-term debt, including securities due within one year: | | |
| **2017** | **$ 7,625** | **$ 8,305** |
| 2016 | $ 7,092 | $ 7,544 |

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates available to the Company.

## 11. DERIVATIVES

The Company is exposed to market risks, including commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a net basis. See Note 10 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

### Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in energy-related commodity prices. The Company manages fuel-hedging programs, implemented per the guidelines of the Alabama PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

Energy-related derivative contracts are accounted for under one of two methods:

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the energy cost recovery clause.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2017 , the net volume of energy-related derivative contracts for natural gas positions totaled 69 million mmBtu for the Company, with the longest hedge date of 2020 over which it is hedging its exposure to the variability in future cash flows for forecasted transactions.

In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The expected volume of natural gas subject to such a feature is 5 million mmBtu.

**Interest Rate Derivatives**

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to earnings.

At December 31, 2017 , there were no interest rate derivatives outstanding.

The estimated pre-tax losses related to interest rate derivatives that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2018 are $6 million . The Company has deferred gains and losses that are expected to be amortized into earnings through 2035.

**Derivative Financial Statement Presentation and Amounts**

The Company enters into energy-related and interest rate derivative contracts that may contain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Fair value amounts of derivative assets and liabilities on the balance sheets are presented net to the extent that there are netting arrangements or similar agreements with the counterparties.

At December 31, 2017 and 2016 , the fair value of energy-related derivatives was reflected on the balance sheets as follows:

| | **2017** | | 2016 | |
|---|---|---|---|---|
| **Derivative Category and Balance Sheet Location** | **Assets** | **Liabilities** | Assets | Liabilities |
| | | *(in millions)* | | |
| **Derivatives designated as hedging instruments for regulatory purposes** | | | | |
| Energy-related derivatives: | | | | |
| Other current assets/Other current liabilities | **$ 2** | **$ 6** | $ 13 | $ 5 |
| Other deferred charges and assets/Other deferred credits and liabilities | **2** | **4** | 7 | 4 |
| **Total derivatives designated as hedging instruments for regulatory purposes** | **$ 4** | **$ 10** | $ 20 | $ 9 |
| **Gross amounts recognized** | **$ 4** | **$ 10** | $ 20 | $ 9 |
| **Gross amounts offset** | **$ (4)** | **$ (4)** | $ (8) | $ (8) |
| **Net amounts recognized in the Balance Sheets** | **$ —** | **$ 6** | $ 12 | $ 1 |

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2017 and 2016 .

**NOTES (continued)**
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At December 31, 2017 and 2016 , the pre-tax effect of unrealized derivative gains (losses) arising from energy-related derivatives designated as regulatory hedging instruments and deferred were as follows:

| | Unrealized Losses | | | Unrealized Gains | | |
|---|---|---|---|---|---|---|
| **Derivative Category** | **Balance Sheet Location** | **2017** | 2016 | **Balance Sheet Location** | **2017** | 2016 |
| | | *(in millions)* | | | *(in millions)* | |
| Energy-related derivatives: | Other regulatory assets, current | **$ (4)** | $ (1) | Other regulatory liabilities, current | **$ 1** | $ 8 |
| | Other regulatory assets, deferred | **(3)** | — | Other regulatory liabilities, deferred | **—** | 4 |
| **Total energy-related derivative gains (losses)** | | **$ (7)** | $ (1) | | **$ 1** | $ 12 |

For the years ended December 31, 2017 , 2016 , and 2015 , the pre-tax effect of interest rate derivatives designated as cash flow hedging instruments on the statements of income was as follows:

| **Derivatives in Cash Flow Hedging Relationships** | **Gain (Loss) Recognized in OCI on Derivative (Effective Portion)** | | | **Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)** | | | |
|---|---|---|---|---|---|---|---|
| | | | | | **Amount** | | |
| **Derivative Category** | **2017** | 2016 | 2015 | **Statements of Income Location** | **2017** | 2016 | 2015 |
| | | *(in millions)* | | | | *(in millions)* | |
| Interest rate derivatives | **$ —** | $ (3) | $ (7) | Interest expense, net of amounts capitalized | **$ (6)** | $ (6) | $ (3) |

There was no material ineffectiveness recorded in earnings for any period presented.

The pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was not material for any year presented.

**Contingent Features**

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies.

At December 31, 2017 , the fair value of derivative liabilities with contingent features was $1 million . However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk related contingent features, at a rating below BBB- and/or Baa3, were $12 million , and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

The Company maintains accounts with certain regional transmission organizations to facilitate financial derivative transactions. Based on the value of the positions in these accounts and the associated margin requirements, the Company may be required to post collateral. At December 31, 2017 , the Company's collateral posted in these accounts was not material.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

## 12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2017 and 2016 is as follows:

| Quarter Ended | Operating Revenues | Operating Income | Net Income After Dividends on Preferred and Preference Stock |
|---|---|---|---|
| | | *(in millions)* | |
| **March 2017** | **$ 1,382** | **$ 376** | **$ 174** |
| **June 2017** | **1,484** | **454** | **230** |
| **September 2017** | **1,740** | **616** | **325** |
| **December 2017** | **1,433** | **268** | **119** |
| | | | |
| March 2016 | $ 1,331 | $ 333 | $ 156 |
| June 2016 | 1,444 | 430 | 213 |
| September 2016 | 1,785 | 650 | 351 |
| December 2016 | 1,329 | 252 | 102 |

The Company's business is influenced by seasonal weather conditions.

**SELECTED FINANCIAL AND OPERATING DATA 2013 - 2017**
**Alabama Power Company 2017 Annual Report**

| | | 2017 | | 2016 | | 2015 | | 2014 | | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Operating Revenues (in millions)** | **$** | **6,039** | $ | 5,889 | $ | 5,768 | $ | 5,942 | $ | 5,618 |
| **Net Income After Dividends on Preferred and Preference Stock (in millions)** | **$** | **848** | $ | 822 | $ | 785 | $ | 761 | $ | 712 |
| **Cash Dividends on Common Stock (in millions)** | **$** | **714** | $ | 765 | $ | 571 | $ | 550 | $ | 644 |
| **Return on Average Common Equity (percent)** | | **12.89** | | 13.34 | | 13.37 | | 13.52 | | 13.07 |
| **Total Assets (in millions)** [(a)(b)] | **$** | **23,864** | $ | 22,516 | $ | 21,721 | $ | 20,493 | $ | 19,185 |
| **Gross Property Additions (in millions)** | **$** | **1,949** | $ | 1,338 | $ | 1,492 | $ | 1,543 | $ | 1,204 |
| **Capitalization (in millions):** | | | | | | | | | | |
| Common stock equity | **$** | **6,829** | $ | 6,323 | $ | 5,992 | $ | 5,752 | $ | 5,502 |
| Preference stock | | **—** | | 196 | | 196 | | 343 | | 343 |
| Redeemable preferred stock | | **291** | | 85 | | 85 | | 342 | | 342 |
| Long-term debt [(a)] | | **7,628** | | 6,535 | | 6,654 | | 6,137 | | 6,195 |
| Total (excluding amounts due within one year) | **$** | **14,748** | $ | 13,139 | $ | 12,927 | $ | 12,574 | $ | 12,382 |
| **Capitalization Ratios (percent):** | | | | | | | | | | |
| Common stock equity | | **46.3** | | 48.1 | | 46.4 | | 45.8 | | 44.4 |
| Preference stock | | **—** | | 1.5 | | 1.5 | | 2.7 | | 2.8 |
| Redeemable preferred stock | | **2.0** | | 0.7 | | 0.7 | | 2.7 | | 2.7 |
| Long-term debt [(a)] | | **51.7** | | 49.7 | | 51.4 | | 48.8 | | 50.1 |
| Total (excluding amounts due within one year) | | **100.0** | | 100.0 | | 100.0 | | 100.0 | | 100.0 |
| **Customers (year-end):** | | | | | | | | | | |
| Residential | | **1,268,271** | | 1,262,752 | | 1,253,875 | | 1,247,061 | | 1,241,998 |
| Commercial | | **199,840** | | 199,146 | | 197,920 | | 197,082 | | 196,209 |
| Industrial | | **6,171** | | 6,090 | | 6,056 | | 6,032 | | 5,851 |
| Other | | **766** | | 762 | | 757 | | 753 | | 751 |
| Total | | **1,475,048** | | 1,468,750 | | 1,458,608 | | 1,450,928 | | 1,444,809 |
| **Employees (year-end)** | | **6,613** | | 6,805 | | 6,986 | | 6,935 | | 6,896 |

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $40 million and $38 million is reflected for years 2014 and 2013, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(b) A reclassification of deferred tax assets from Total Assets of $20 million and $27 million is reflected for years 2014 and 2013, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

**SELECTED FINANCIAL AND OPERATING DATA 2013 - 2017 (continued)**
**Alabama Power Company 2017 Annual Report**

| | 2017 | 2016 | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|
| **Operating Revenues ( in millions ):** | | | | | |
| Residential | **$ 2,302** | $ 2,322 | $ 2,207 | $ 2,209 | $ 2,079 |
| Commercial | **1,649** | 1,627 | 1,564 | 1,533 | 1,477 |
| Industrial | **1,477** | 1,416 | 1,436 | 1,480 | 1,369 |
| Other | **30** | (43) | 27 | 27 | 27 |
| Total retail | **5,458** | 5,322 | 5,234 | 5,249 | 4,952 |
| Wholesale — non-affiliates | **276** | 283 | 241 | 281 | 248 |
| Wholesale — affiliates | **97** | 69 | 84 | 189 | 212 |
| Total revenues from sales of electricity | **5,831** | 5,674 | 5,559 | 5,719 | 5,412 |
| Other revenues | **208** | 215 | 209 | 223 | 206 |
| Total | **$ 6,039** | $ 5,889 | $ 5,768 | $ 5,942 | $ 5,618 |
| **Kilowatt-Hour Sales ( in millions ):** | | | | | |
| Residential | **17,219** | 18,343 | 18,082 | 18,726 | 17,920 |
| Commercial | **13,606** | 14,091 | 14,102 | 14,118 | 13,892 |
| Industrial | **22,687** | 22,310 | 23,380 | 23,799 | 22,904 |
| Other | **198** | 208 | 201 | 211 | 211 |
| Total retail | **53,710** | 54,952 | 55,765 | 56,854 | 54,927 |
| Wholesale — non-affiliates | **5,415** | 5,744 | 3,567 | 3,588 | 3,711 |
| Wholesale — affiliates | **4,166** | 3,177 | 4,515 | 6,713 | 7,672 |
| Total | **63,291** | 63,873 | 63,847 | 67,155 | 66,310 |
| **Average Revenue Per Kilowatt-Hour ( cents ):** | | | | | |
| Residential | **13.37** | 12.66 | 12.21 | 11.80 | 11.60 |
| Commercial | **12.12** | 11.55 | 11.09 | 10.86 | 10.63 |
| Industrial | **6.51** | 6.35 | 6.14 | 6.22 | 5.98 |
| Total retail | **10.16** | 9.68 | 9.39 | 9.23 | 9.02 |
| Wholesale | **3.89** | 3.95 | 4.02 | 4.56 | 4.04 |
| Total sales | **9.21** | 8.88 | 8.71 | 8.52 | 8.16 |
| **Residential Average Annual Kilowatt-Hour Use Per Customer** | **13,601** | 14,568 | 14,454 | 15,051 | 14,451 |
| **Residential Average Annual Revenue Per Customer** | **$ 1,819** | $ 1,844 | $ 1,764 | $ 1,775 | $ 1,676 |
| **Plant Nameplate Capacity Ratings ( year-end ) ( megawatts )** | **11,797** | 11,797 | 11,797 | 12,222 | 12,222 |
| **Maximum Peak-Hour Demand ( megawatts ):** | | | | | |
| Winter | **10,513** | 10,282 | 12,162 | 11,761 | 9,347 |
| Summer | **10,711** | 10,932 | 11,292 | 11,054 | 10,692 |
| **Annual Load Factor ( percent )** | **63.5** | 63.5 | 58.4 | 61.4 | 64.9 |
| **Plant Availability ( percent ):** | | | | | |
| Fossil-steam | **82.8** | 83.0 | 81.5 | 82.5 | 87.3 |
| Nuclear | **97.6** | 88.0 | 92.1 | 93.3 | 90.7 |
| **Source of Energy Supply ( percent ):** | | | | | |
| Coal | **44.8** | 47.1 | 49.1 | 49.0 | 50.0 |
| Nuclear | **22.2** | 20.3 | 21.3 | 20.7 | 20.3 |
| Hydro | **5.4** | 4.8 | 5.6 | 5.5 | 8.1 |
| Gas | **18.1** | 17.1 | 14.6 | 15.4 | 15.7 |
| Purchased power — | | | | | |
| From non-affiliates | **4.6** | 4.8 | 4.4 | 3.6 | 2.9 |
| From affiliates | **4.9** | 5.9 | 5.0 | 5.8 | 3.0 |
| Total | **100.0** | 100.0 | 100.0 | 100.0 | 100.0 |

# GEORGIA POWER COMPANY

# FINANCIAL SECTION

**MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING**
**Georgia Power Company 2017 Annual Report**

The management of Georgia Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2017 .

/s/ W. Paul Bowers
W. Paul Bowers
Chairman, President, and Chief Executive Officer

/s/ Xia Liu
Xia Liu
Executive Vice President, Chief Financial Officer, and Treasurer

February 20, 2018

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the stockholder and the Board of Directors of Georgia Power Company

**Opinion on the Financial Statements**

We have audited the accompanying balance sheets and statements of capitalization of Georgia Power Company (the Company) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2017 and 2016 , the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2017 , and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements (pages II-270 to II-321 ) present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016 , and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017 , in conformity with accounting principles generally accepted in the United States of America.

**Basis for Opinion**

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 20, 2018

We have served as the Company's auditor since 2002.

**DEFINITIONS**

| Term | Meaning |
|---|---|
| 2013 ARP | Alternative Rate Plan approved by the Georgia PSC in 2013 for Georgia Power for the years 2014 through 2016 and subsequently extended through 2019 |
| AFUDC | Allowance for funds used during construction |
| Alabama Power | Alabama Power Company |
| ARO | Asset retirement obligation |
| ASC | Accounting Standards Codification |
| ASU | Accounting Standards Update |
| Bechtel | Bechtel Power Corporation |
| CCR | Coal combustion residuals |
| Clean Air Act | Clean Air Act Amendments of 1990 |
| $CO_2$ | Carbon dioxide |
| Contractor Settlement Agreement | The December 31, 2015 agreement between Westinghouse and the Vogtle Owners resolving disputes between the Vogtle Owners and the EPC Contractor under the Vogtle 3 and 4 Agreement |
| CWIP | Construction work in progress |
| DOE | U.S. Department of Energy |
| Eligible Project Costs | Certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the loan guarantee program established under Title XVII of the Energy Policy Act of 2005 |
| EPA | U.S. Environmental Protection Agency |
| EPC Contractor | Westinghouse and its affiliate, WECTEC Global Project Services Inc.; the former engineering, procurement, and construction contractor for Plant Vogtle Units 3 and 4 |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| FFB | Federal Financing Bank |
| GAAP | U.S. generally accepted accounting principles |
| Gulf Power | Gulf Power Company |
| Interim Assessment Agreement | Agreement entered into by the Vogtle Owners and the EPC Contractor to allow construction to continue after the EPC Contractor's bankruptcy filing |
| IRS | Internal Revenue Service |
| ITC | Investment tax credit |
| KWH | Kilowatt-hour |
| LIBOR | London Interbank Offered Rate |
| Loan Guarantee Agreement | Loan guarantee agreement entered into by Georgia Power with the DOE in 2014, under which the proceeds of borrowings may be used to reimburse Georgia Power for Eligible Project Costs incurred in connection with its construction of Plant Vogtle Units 3 and 4 |
| LTSA | Long-term service agreement |
| Mississippi Power | Mississippi Power Company |
| mmBtu | Million British thermal units |
| Moody's | Moody's Investors Service, Inc. |
| MW | Megawatt |
| NCCR | Nuclear Construction Cost Recovery |
| $NO_X$ | Nitrogen oxide |
| NRC | U.S. Nuclear Regulatory Commission |
| OCI | Other comprehensive income |

**DEFINITIONS**
(continued)

| Term | Meaning |
|---|---|
| power pool | The operating arrangement whereby the integrated generating resources of the traditional electric operating companies and Southern Power (excluding subsidiaries) are subject to joint commitment and dispatch in order to serve their combined load obligations |
| PPA | Power purchase agreement |
| PSC | Public Service Commission |
| PTC | Production tax credit |
| ROE | Return on equity |
| S&P | S&P Global Ratings, a division of S&P Global Inc. |
| SCS | Southern Company Services, Inc. (the Southern Company system service company) |
| SEC | U.S. Securities and Exchange Commission |
| SEGCO | Southern Electric Generating Company |
| $SO_2$ | Sulfur dioxide |
| Southern Company | The Southern Company |
| Southern Company Gas | Southern Company Gas and its subsidiaries |
| Southern Company system | Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), SEGCO, Southern Nuclear, SCS, Southern Linc, PowerSecure, Inc. (as of May 9, 2016), and other subsidiaries |
| Southern Linc | Southern Communications Services, Inc. |
| Southern Nuclear | Southern Nuclear Operating Company, Inc. |
| Southern Power | Southern Power Company and its subsidiaries |
| Tax Reform Legislation | The Tax Cuts and Jobs Act, which was signed into law on December 22, 2017 and became effective on January 1, 2018 |
| Toshiba | Toshiba Corporation, parent company of Westinghouse |
| Toshiba Guarantee | Certain payment obligations of the EPC Contractor guaranteed by Toshiba |
| traditional electric operating companies | Alabama Power, Georgia Power Company, Gulf Power, and Mississippi Power |
| VCM | Vogtle Construction Monitoring |
| Vogtle 3 and 4 Agreement | Agreement entered into with the EPC Contractor in 2008 by Georgia Power, acting for itself and as agent for the Vogtle Owners, pursuant to which the EPC Contractor agreed to design, engineer, procure, construct, and test Plant Vogtle Units 3 and 4 |
| Vogtle Owners | Georgia Power, Oglethorpe Power Corporation, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light, and Sinking Fund Commissioners |
| Vogtle Services Agreement | The June 9, 2017 services agreement between the Vogtle Owners and the EPC Contractor, as amended and restated on July 20, 2017, for the EPC Contractor to transition construction management of Plant Vogtle Units 3 and 4 to Southern Nuclear and to provide ongoing design, engineering, and procurement services to Southern Nuclear |
| Westinghouse | Westinghouse Electric Company LLC |

**MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS**
**Georgia Power Company 2017 Annual Report**

## OVERVIEW

### Business Activities

Georgia Power Company (the Company) operates as a vertically integrated utility providing electric service to retail customers within its traditional service territory located within the State of Georgia and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of providing electric service. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, stringent environmental standards, reliability, fuel, capital expenditures, and restoration following major storms. The Company has various regulatory mechanisms that operate to address cost recovery. Effectively operating pursuant to these regulatory mechanisms and appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future. The Company is required to file a base rate case with the Georgia PSC by July 1, 2019.

The Company continues to focus on several key performance indicators, including, but not limited to, customer satisfaction, plant availability, system reliability, the execution of major construction projects, and net income. The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys to evaluate the Company's results and generally targets the top quartile of these surveys in measuring performance.

See RESULTS OF OPERATIONS herein for information on the Company's financial performance.

### Nuclear Construction

In 2009, the Georgia PSC certified construction of Plant Vogtle Units 3 and 4. In 2012, the NRC issued the related combined construction and operating licenses, which allowed full construction of the two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities to begin. Until March 2017, construction on Plant Vogtle Units 3 and 4 continued under the Vogtle 3 and 4 Agreement, which was a substantially fixed price agreement. On March 29, 2017, the EPC Contractor filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code.

In connection with the EPC Contractor's bankruptcy filing, the Company, acting for itself and as agent for the Vogtle Owners, entered into the Interim Assessment Agreement with the EPC Contractor to allow construction to continue. The Interim Assessment Agreement expired on July 27, 2017 when the Vogtle Services Agreement became effective. In August 2017, following completion of comprehensive cost to complete and cancellation cost assessments, the Company filed its seventeenth VCM report with the Georgia PSC, which included a recommendation to continue construction of Plant Vogtle Units 3 and 4, with Southern Nuclear serving as project manager and Bechtel serving as the primary construction contractor. On December 21, 2017, the Georgia PSC approved the Company's recommendation to continue construction.

The Company expects Plant Vogtle Units 3 and 4 to be placed in service by November 2021 and November 2022, respectively. The Company's revised capital cost forecast for its 45.7% proportionate share of Plant Vogtle Units 3 and 4 is $8.8 billion ( $7.3 billion after reflecting the impact of payments received under a settlement agreement regarding the Toshiba Guarantee (Guarantee Settlement Agreement) and certain refunds to customers ordered by the Georgia PSC (Customer Refunds)). The Company's CWIP balance for Plant Vogtle Units 3 and 4 was $3.3 billion at December 31, 2017 , which is net of the Guarantee Settlement Agreement payments less the Customer Refunds. The Company estimates that its financing costs for construction of Plant Vogtle Units 3 and 4 will total approximately $3.1 billion , of which $1.6 billion had been incurred through December 31, 2017 .

See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Nuclear Construction" herein for additional information on Plant Vogtle Units 3 and 4.

### Earnings

The Company's 2017 net income after dividends on preferred and preference stock was $1.4 billion , representing a $84 million , or 6.3% , increase over the previous year. The increase was due primarily to lower non-fuel operations and maintenance expenses, primarily as a result of cost containment and modernization initiatives, partially offset by lower revenues resulting from milder weather and lower customer usage as compared to 2016.

The Company's 2016 net income after dividends on preferred and preference stock was $1.3 billion , representing a $70 million , or 5.6% , increase over the previous year. The increase was due primarily to an increase in base retail revenues effective January 1, 2016, as authorized by the Georgia PSC, the 2015 correction of a customer billing error, and higher retail revenues in the third quarter 2016 due to warmer weather as compared to the corresponding period in 2015, partially offset by an expected refund to retail customers as a result of the Company's retail ROE exceeding the retail ROE range allowed under the 2013 ARP during 2016. Higher non-fuel operating expenses also partially offset the revenue increase.

See Note 1 to the financial statements under "General" and FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Rate Plans" herein for additional information related to the 2015 error correction and the refund to retail customers, respectively.

**RESULTS OF OPERATIONS**

A condensed income statement for the Company follows:

| | Amount | Increase (Decrease) from Prior Year | |
|---|---|---|---|
| | **2017** | **2017** | 2016 |
| | | *(in millions)* | |
| Operating revenues | **$ 8,310** | **$ (73)** | $ 57 |
| Fuel | **1,671** | **(136)** | (226) |
| Purchased power | **1,038** | **159** | 15 |
| Other operations and maintenance | **1,653** | **(307)** | 116 |
| Depreciation and amortization | **895** | **40** | 9 |
| Taxes other than income taxes | **409** | **4** | 14 |
| Total operating expenses | **5,666** | **(240)** | (72) |
| Operating income | **2,644** | **167** | 129 |
| Interest expense, net of amounts capitalized | **419** | **31** | 25 |
| Other income (expense), net | **33** | **(5)** | (23) |
| Income taxes | **830** | **50** | 11 |
| Net income | **1,428** | **81** | 70 |
| Dividends on preferred and preference stock | **14** | **(3)** | — |
| Net income after dividends on preferred and preference stock | **$ 1,414** | **$ 84** | $ 70 |

### *Operating Revenues*

Operating revenues for 2017 were $8.3 billion , reflecting a $73 million decrease from 2016 . Details of operating revenues were as follows:

| | Amount | |
|---|---|---|
| | **2017** | 2016 |
| | *(in millions)* | |
| Retail — prior year | **$ 7,772** | $ 7,727 |
| Estimated change resulting from — | | |
| Rates and pricing | **114** | 154 |
| Sales decline | **(33)** | (10) |
| Weather | **(166)** | 113 |
| Fuel cost recovery | **51** | (212) |
| Retail — current year | **7,738** | 7,772 |
| Wholesale revenues — | | |
| Non-affiliates | **163** | 175 |
| Affiliates | **26** | 42 |
| Total wholesale revenues | **189** | 217 |
| Other operating revenues | **383** | 394 |
| Total operating revenues | **$ 8,310** | $ 8,383 |
| Percent change | **(0.9)%** | 0.7% |

Retail revenues of $7.7 billion in 2017 decreased $34 million , or 0.4% , compared to 2016 . The significant factors driving this change are shown in the preceding table. The increase in rates and pricing was primarily due to an increase in revenues related to the recovery of Plant Vogtle Units 3 and 4 construction financing costs under the NCCR tariff.

Retail revenues of $7.8 billion in 2016 increased $45 million , or 0.6% , compared to 2015 . The significant factors driving this change are shown in the preceding table. The increase in rates and pricing was primarily due to increases in base tariffs approved under the 2013 ARP and the NCCR tariff, all effective January 1, 2016, and the 2015 correction of a customer billing error. The increase was partially offset by an adjustment for an expected refund to retail customers as a result of the Company's retail ROE exceeding the retail ROE range allowed under the 2013 ARP during 2016.

See Note 1 to the financial statements under "General" for additional information on the customer billing error correction and Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" and " – Nuclear Construction" for additional information on the rate changes. Also see "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales decline and weather.

Electric rates include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these fuel cost recovery provisions, fuel revenues generally equal fuel expenses and do not affect net income. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" herein for additional information.

Wholesale revenues from power sales to non-affiliated utilities were as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| Capacity and other | **$ 67** | $ 72 | $ 108 |
| Energy | **96** | 103 | 107 |
| Total non-affiliated | **$ 163** | $ 175 | $ 215 |

Wholesale capacity revenues from PPAs are recognized either on a levelized basis over the appropriate contract period or the amounts billable under the contract terms and provide for recovery of fixed costs and a return on investment. Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost of energy.

Wholesale revenues from non-affiliated sales decrease d $12 million , or 6.9% , in 2017 as compared to 2016 and decrease d $40 million , or 18.6% , in 2016 as compared to 2015 . The decrease in 2017 was related to decreases of $5 million in capacity revenues and $7 million in energy revenues. The decrease in 2016 was related to decreases of $36 million in capacity revenues and $4 million in energy revenues. The decreases in capacity revenues reflect the expiration of wholesale contracts in the first and second quarters of 2016. The decrease in capacity revenues in 2016 also reflects the retirement of 14 coal-fired generating units since March 31, 2015 as a result of the Company's environmental compliance strategy. The decrease in energy revenues in 2017 was primarily due to lower demand and the effects of the expired contracts. The decrease in energy revenues in 2016 was primarily due to lower fuel prices. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations – Air Quality" herein for additional information regarding the Company's environmental compliance strategy.

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost. In 2017 , wholesale revenues from sales to affiliates decrease d $16 million as compared to 2016 due to a 42.8% decrease in KWH sales as a result of the lower market cost of available energy compared to the cost of Company-owned generation. In 2016 , wholesale revenues from sales to affiliates increase d $22 million as compared to 2015 due to a 153.5% increase in KWH sales as a result of the lower cost of Company-owned generation compared to the market cost of available energy, partially offset by lower coal and natural gas prices.

Other operating revenues decrease d $11 million , or 2.8% , in 2017 from the prior year primarily due to a $15 million decrease in open access transmission tariff revenues, primarily as a result of the expiration of long-term transmission services contracts, and a $14 million adjustment in 2016 for customer temporary facilities services revenues, partially offset by a $13 million increase in outdoor lighting sales revenues due to increased sales in new and replacement markets, primarily attributable to LED conversions.

Other operating revenues increase d $30 million , or 8.2% , in 2016 from the prior year primarily due to a $14 million increase related to customer temporary facilities services revenues and a $12 million increase in outdoor lighting revenues due to increased sales in new and replacement markets, primarily attributable to LED conversions.

*Energy Sales*

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2017 and the percent change from the prior year were as follows:

| | **Total KWHs** | **Total KWH Percent Change** | | **Weather-Adjusted Percent Change** | |
|---|---|---|---|---|---|
| | **2017** | **2017** | 2016 | **2017** | 2016 |
| | *(in billions)* | | | | |
| Residential | **26.1** | **(5.2)%** | 3.5 % | **(0.2)%** | 1.0 % |
| Commercial | **32.2** | **(2.4)** | 0.7 | **(0.9)** | (1.0) |
| Industrial | **23.5** | **(1.0)** | (0.2) | **(0.1)** | (0.9) |
| Other | **0.6** | **(4.2)** | (3.5) | **(4.0)** | (3.5) |
| Total retail | **82.4** | **(2.9)** | 1.3 | **(0.4)%** | (0.4)% |
| Wholesale | | | | | |
| Non-affiliates | **3.3** | **(4.0)** | (2.5) | | |
| Affiliates | **0.8** | **(42.8)** | 153.5 | | |
| Total wholesale | **4.1** | **(15.3)** | 18.8 | | |
| Total energy sales | **86.5** | **(3.6)%** | 2.1 % | | |

Changes in retail energy sales are generally the result of changes in electricity usage by customers, changes in weather, and changes in the number of customers.

In 2017 , KWH sales for the residential class decreased 5.2% compared to 2016 primarily due to milder weather in 2017. Weather-adjusted residential KWH sales decreased by 0.2% primarily due to a decline in average customer usage resulting from an increase in multi-family housing and energy saving initiatives, partially offset by customer growth. Weather-adjusted commercial KWH sales decreased by 0.9% primarily due to a decline in average customer usage resulting from an increase in electronic commerce transactions and energy saving initiatives, partially offset by customer growth. Weather-adjusted industrial KWH sales were essentially flat primarily due to decreased demand in the chemicals and paper sectors, offset by increased demand in the textile, non-manufacturing, and rubber sectors. Additionally, Hurricane Irma negatively impacted customer usage for all customer classes for the period.

In 2016, KWH sales for the residential class increased 3.5% compared to 2015 primarily due to warmer weather in the third quarter 2016 as compared to the corresponding period in 2015 and increased customer growth, partially offset by decreased customer usage. Weather-adjusted residential KWH sales increased by 1.0% primarily due to an increase of approximately 28,000 residential customers since December 31, 2015, partially offset by a decline in customer usage primarily resulting from an increase in multi-family housing and efficiency improvements in residential appliances and lighting. Weather-adjusted commercial KWH sales decreased by 1.0% primarily due to a decline in average customer usage resulting from an increase in electronic commerce transactions and energy saving initiatives, partially offset by an increase of approximately 2,600 commercial customers since December 31, 2015. Weather-adjusted industrial KWH sales decreased 0.9% primarily due to decreased demand in the pipeline, primary metals, stone, clay, and glass, and textile sectors, partially offset by increased demand in the non-manufacturing sector.

See "Operating Revenues" above for a discussion of significant changes in wholesale sales to non-affiliates and affiliated companies.

***Fuel and Purchased Power Expenses***

Fuel costs constitute one of the largest expenses for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

Details of the Company's generation and purchased power were as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| Total generation *(in billions of KWHs)* | **63.2** | 68.4 | 65.9 |
| Total purchased power *(in billions of KWHs)* | **26.9** | 24.8 | 25.6 |
| Sources of generation *(percent)* — | | | |
| Gas | **41** | 38 | 39 |
| Coal | **32** | 36 | 34 |
| Nuclear | **25** | 24 | 25 |
| Hydro | **2** | 2 | 2 |
| Cost of fuel, generated *(in cents per net KWH)* — | | | |
| Gas | **2.68** | 2.36 | 2.47 |
| Coal | **3.17** | 3.28 | 4.55 |
| Nuclear | **0.83** | 0.85 | 0.78 |
| Average cost of fuel, generated *(in cents per net KWH)* | **2.36** | 2.33 | 2.77 |
| Average cost of purchased power *(in cents per net KWH)* (*) | **4.62** | 4.53 | 4.33 |

(*) Average cost of purchased power includes fuel purchased by the Company for tolling agreements where power is generated by the provider.

Fuel and purchased power expenses were $2.7 billion in 2017 , an increase of $23 million , or 0.9% , compared to 2016 . The increase was primarily due to an $84 million increase in the average cost of fuel and purchased power primarily related to higher natural gas prices, partially offset by a net decrease of $61 million related to the volume of KWHs generated and purchased primarily due to milder weather, resulting in lower customer demand.

Fuel and purchased power expenses were $2.7 billion in 2016 , a decrease of $211 million , or 7.3% , compared to 2015 . The decrease was primarily due to a $285 million net decrease in the average cost of fuel and purchased power due to lower coal and natural gas prices, partially offset by a $74 million net increase in the volume of KWHs generated and purchased to meet customer demand.

Fuel and purchased power energy transactions do not have a significant impact on earnings since these fuel expenses are generally offset by fuel revenues through the Company's fuel cost recovery mechanism. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" herein for additional information.

*Fuel*

Fuel expense was $1.7 billion in 2017 , a decrease of $136 million , or 7.5% , compared to 2016 . The decrease was primarily due to a decrease of 7.7% in the volume of KWHs generated largely due to milder weather, resulting in lower customer demand, partially offset by an increase of 13.6% in the average cost of natural gas per KWH generated. Fuel expense was $1.8 billion in 2016 , a decrease of $226 million , or 11.1% , compared to 2015 . The decrease was primarily due to a decrease of 18.6% in the average cost of coal and natural gas per KWH generated, partially offset by an increase of 10.0% in the volume of KWHs generated by coal.

*Purchased Power - Non-Affiliates*

Purchased power expense from non-affiliates was $416 million in 2017 , an increase of $55 million , or 15.2% , compared to 2016 . The increase was primarily due to a 13.4% increase in the volume of KWHs purchased primarily due to unplanned outages at Company-owned generating units. Purchased power expense from non-affiliates was $361 million in 2016 , an increase of $72 million , or 24.9% , compared to 2015 . The increase was primarily due to a 36.8% increase in the volume of KWHs purchased to meet customer demand, partially offset by a 12.5% decrease in the average cost per KWH purchased due to lower natural gas prices.

Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation.

*Purchased Power - Affiliates*

Purchased power expense from affiliates was $622 million in 2017 , an increase of $104 million , or 20.1% , compared to 2016 . The increase was primarily due to a 7.0% increase in the volume of KWHs purchased to support Southern Company system transmission reliability and as a result of unplanned outages at Company-owned generating units and a 1.8% increase in the average cost per KWH purchased primarily resulting from higher natural gas prices. Purchased power expense from affiliates was $518 million in 2016 , a decrease of $57 million , or 9.9% , compared to 2015 . The decrease was primarily due to an 11.9% decrease in the volume of KWHs purchased due to the lower market cost of available energy as compared to Southern Company system resources, partially offset by a 6.2% increase in the average cost per KWH purchased.

Energy purchases from affiliates will vary depending on the demand and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC or other contractual agreements, all as approved by the FERC.

***Other Operations and Maintenance Expenses***

In 2017 , other operations and maintenance expenses decrease d $307 million , or 15.7% , compared to 2016 . The decrease was primarily due to cost containment and modernization activities implemented in the third quarter 2016 that contributed to decreases of $85 million in generation maintenance costs, $49 million in employee benefits, $46 million in transmission and distribution overhead line maintenance, and $22 million in customer accounts and sales costs. Other factors include a $40 million increase in gains from sales of assets, a $19 million decrease in scheduled generation outage costs, and a $15 million decrease in customer assistance expenses, primarily in demand-side management costs related to the timing of new programs.

In 2016 , other operations and maintenance expenses increase d $116 million , or 6.3% , compared to 2015 . The increase was primarily due to a $37 million decrease in gains from sales of assets, a $36 million charge in connection with cost containment activities, a $30 million increase in overhead line maintenance, a $15 million increase in hydro and gas generation maintenance, a $10 million increase in customer accounts, service, and sales costs, and a $7 million increase in material costs related to higher generation volumes. The increase was partially offset by a decrease of $36 million in pension costs.

See FUTURE EARNINGS POTENTIAL – "Other Matters" herein and Note 2 to the financial statements for additional information related to the cost containment and modernization activities and pension costs, respectively.

***Depreciation and Amortization***

Depreciation and amortization increase d $40 million , or 4.7% , in 2017 compared to 2016 . The increase was primarily due to a $33 million increase related to additional plant in service and a $14 million decrease in amortization of regulatory liabilities related to other cost of removal obligations that expired in December 2016, partially offset by a $9 million decrease in depreciation related to generating unit retirements in 2016 and amortization of regulatory assets related to certain cancelled environmental and fuel conversion projects that expired in December 2016.

Depreciation and amortization increase d $9 million , or 1.1% , in 2016 compared to 2015 . The increase was primarily due to a $34 million increase related to additional plant in service and a $9 million increase in other cost of removal, partially offset by an $18 million decrease related to amortization of certain nuclear construction financing costs that was completed in December 2015 and a decrease of $16 million related to unit retirements.

See Note 1 to the financial statements under "Depreciation and Amortization" for additional information.

***Taxes Other Than Income Taxes***

In 2017 , taxes other than income taxes increase d $4 million , or 1.0% , compared to 2016 . In 2016 , taxes other than income taxes increase d $14 million , or 3.6% , compared to 2015 primarily due to increases of $7 million in property taxes as a result of an increase in the assessed value of property and $4 million in payroll taxes.

***Interest Expense, Net of Amounts Capitalized***

In 2017 , interest expense, net of amounts capitalized increase d $31 million , or 8.0% , compared to the prior year primarily due to an increase in outstanding borrowings.

In 2016 , interest expense, net of amounts capitalized increase d $25 million , or 6.9% , compared to the prior year. The increase was primarily due to a $34 million increase in interest due to additional long-term borrowings from the FFB and higher interest rates on obligations for pollution control revenue bonds remarketed in 2015, partially offset by an increase of $4 million in AFUDC debt.

***Other Income (Expense), Net***

In 2017 , other income (expense), net decrease d $5 million compared to the prior year primarily due to a $10 million increase in donations and an $8 million decrease in AFUDC equity resulting from higher short-term borrowings, partially offset by a $7 million increase in third party infrastructure services revenue and a $6 million increase in wholesale operating fee revenue associated with contractual targets.

In 2016 , other income (expense), net decrease d $23 million compared to the prior year primarily due to decreases of $8 million in customer contributions in aid of construction, $6 million in wholesale operating fee revenue associated with contractual targets, and $4 million in gains on purchases of state tax credits.

***Income Taxes***

Income taxes increase d $50 million , or 6.4% , in 2017 compared to the prior year primarily due to higher pre-tax earnings, partially offset by an adjustment related to Tax Reform Legislation. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation " herein and Note 5 to the financial statements for additional information.

Income taxes increase d $11 million , or 1.4% , in 2016 compared to the prior year primarily due to higher pre-tax earnings, partially offset by decreases in non-deductible book depreciation and increased state investment tax credits.

***Dividends on Preferred and Preference Stock***

Dividends on preferred and preference stock decrease d $3 million , or 17.6% , in 2017 compared to the prior year due to the redemption in October 2017 of all outstanding shares of the Company's preferred and preference stock. See Note 6 to the financial statements under "Outstanding Classes of Capital Stock" for additional information.

**Effects of Inflation**

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

## FUTURE EARNINGS POTENTIAL

**General**

The Company operates as a vertically integrated utility providing electric service to retail customers within its traditional service territory located in the State of Georgia and to wholesale customers in the Southeast. Prices for electricity provided by the

Company to retail customers are set by the Georgia PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of providing electric service. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs and limited projected demand growth over the next several years. Plant Vogtle Units 3 and 4 construction and rate recovery are also major factors. Future earnings will be driven primarily by customer growth. Earnings will also depend upon maintaining and growing sales, considering, among other things, the adoption and/or penetration rates of increasingly energy-efficient technologies, increasing volumes of electronic commerce transactions, and higher multi-family home construction, all of which could contribute to a net reduction in customer usage. Earnings are subject to a variety of other factors. These factors include weather, competition, new energy contracts with other utilities, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territory. Demand for electricity is primarily driven by the pace of economic growth that may be affected by changes in regional and global economic conditions, which may impact future earnings.

On December 22, 2017, the Tax Reform Legislation was signed into law and became effective on January 1, 2018, which, among other things, reduces the federal corporate income tax rate to 21% and changes rates of depreciation and the business interest deduction. See " Income Tax Matters – Federal Tax Reform Legislation " and FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein and Notes 3 and 5 to the financial statements under "Retail Regulatory Matters – Rate Plans" and "Current and Deferred Income Taxes," respectively, for additional information.

**Environmental Matters**

The Company's operations are regulated by state and federal environmental agencies through a variety of laws and regulations governing air, water, land, and protection of other natural resources. The Company maintains a comprehensive environmental compliance strategy to assess upcoming requirements and compliance costs associated with these environmental laws and regulations. The costs, including capital expenditures and operations and maintenance costs, required to comply with environmental laws and regulations may impact future unit retirement and replacement decisions, results of operations, cash flows, and financial condition. Compliance costs may result from the installation of additional environmental controls, closure and monitoring of CCR facilities, unit retirements, and adding or changing fuel sources for certain existing units, as well as related upgrades to the transmission system. A major portion of these compliance costs are expected to be recovered through existing ratemaking provisions. The ultimate impact of the environmental laws and regulations discussed below will depend on various factors, such as state adoption and implementation of requirements, the availability and cost of any deployed control technology, and the outcome of pending and/or future legal challenges.

New or revised environmental laws and regulations could affect many areas of the Company's operations. The impact of any such changes cannot be determined at this time. Environmental compliance costs could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis . The Company's Environmental Compliance Cost Recovery (ECCR) tariff allows for the recovery of capital and operations and maintenance costs related to environmental controls mandated by state and federal regulations . Further, increased costs that are recovered through regulated rates could contribute to reduced demand for electricity , which could negatively affect results of operations, cash flows, and financial condition. Additionally, many commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity .

Through 2017 , the Company has invested approximately $5.5 billion in environmental capital retrofit projects to comply with environmental requirements, with annual totals of approximately $0.3 billion, $0.2 billion, and $0.3 billion for 2017 , 2016 , and 2015 , respectively. Although the timing, requirements, and estimated costs could change as environmental laws and regulations are adopted or modified, as compliance plans are revised or updated, and as legal challenges to rules are initiated or completed, the Company's current compliance strategy estimates capital expenditures of $1.2 billion from 2018 through 2022 , with annual totals of approximately $0.5 billion , $0.1 billion , $0.2 billion , $0.2 billion , and $0.2 billion for 2018 , 2019 , 2020 , 2021 , and 2022 , respectively. These estimates do not include any potential compliance costs associated with the regulation of $CO_2$ emissions from fossil fuel-fired electric generating units. See "Global Climate Issues" herein for additional information. The Company also anticipates expenditures associated with ash pond closure and ground water monitoring under the Disposal of Coal Combustion Residuals from Electric Utilities rule (CCR Rule), which are reflected in the Company's ARO liabilities. See FINANCIAL

CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

***Environmental Laws and Regulations***

*Air Quality*

The EPA has set National Ambient Air Quality Standards (NAAQS) for six air pollutants (carbon monoxide, lead, nitrogen dioxide, ozone, particulate matter, and $SO_2$), which it reviews and revises periodically. Revisions to these standards can require additional emission controls, improvements in control efficiency, or fuel changes which can result in increased compliance and operational costs. NAAQS requirements can also adversely affect the siting of new facilities. In 2015, the EPA published a more stringent eight-hour ozone NAAQS. The EPA plans to complete designations for this rule by no later than April 30, 2018 and intends to designate an eight-county area within metropolitan Atlanta as nonattainment . No other areas within the Company's service territory have been or are anticipated to be designated nonattainment under the 2015 ozone NAAQS. In 2010, the EPA revised the NAAQS for $SO_2$, establishing a new one-hour standard, and is completing designations in multiple phases. The EPA has issued several rounds of area designations and no areas in the vicinity of Company -owned $SO_2$ sources have been designated nonattainment under the 2010 one-hour $SO_2$ NAAQS. However, final eight-hour ozone and $SO_2$ one-hour designations for certain areas are still pending and, if other areas are designated as nonattainment in the future, increased compliance costs could result.

In 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) and its $NO_X$ annual, $NO_X$ seasonal, and $SO_2$ annual programs. CSAPR is an emissions trading program that addresses the impacts of the interstate transport of $SO_2$ and $NO_X$ emissions from fossil fuel-fired power plants located in upwind states in the eastern half of the U.S. on air quality in downwind states. The Company has fossil fuel-fired generation subject to these requirements. In October 2016, the EPA published a final rule that revised the CSAPR seasonal $NO_X$ program, establishing more stringent $NO_X$ emissions budgets in Alabama . Georgia's seasonal $NO_X$ budget remains unchanged. Increases in either future fossil fuel-fired generation or the cost of CSAPR allowances could have a negative financial impact on results of operations for the Company .

The EPA finalized regional haze regulations in 2005 and 2017. These regulations require states, tribal governments, and various federal agencies to develop and implement plans to reduce pollutants that impair visibility and demonstrate reasonable progress toward the goal of restoring natural visibility conditions in certain areas, including national parks and wilderness areas. States must submit a revised state implementation plan (SIP) to the EPA by July 31, 2021, demonstrating reasonable progress towards achieving visibility improvement goals. State implementation of reasonable progress could require further reductions in $SO_2$ or $NO_X$ emissions, which could result in increased compliance costs.

In 2015, the EPA published a final rule requiring certain states (including Georgia and Alabama ) to revise or remove the provisions of their SIPs regulating excess emissions at industrial facilities, including electric generating facilities, during periods of startup, shut-down, or malfunction (SSM). The state excess emission rules provide necessary operational flexibility to affected units during periods of SSM and, if removed, could affect unit availability and result in increased operations and maintenance costs for the Company . The EPA has not yet responded to the SIP revisions proposed by the State of Georgia.

*Water Quality*

In 2014, the EPA finalized requirements under Section 316(b) of the Clean Water Act (CWA) to regulate cooling water intake structures at existing power plants and manufacturing facilities in order to minimize their effects on fish and other aquatic life. The regulation requires plant-specific studies to determine applicable measures to protect organisms that either get caught on the intake screens (impingement) or are drawn into the cooling system (entrainment). The ultimate impact of this rule will depend on the outcome of these plant-specific studies and any additional protective measures required to be incorporated into each plant's National Pollutant Discharge Elimination System (NPDES) permit based on site-specific factors.

In 2015, the EPA finalized the steam electric effluent limitations guidelines (ELG) rule that set national standards for wastewater discharges from steam electric generating units. The rule prohibits effluent discharges of certain wastestreams and imposes stringent arsenic, mercury, selenium, and nitrate/nitrite limits on scrubber wastewater discharges. The revised technology-based limits and compliance dates may require extensive modifications to existing ash and wastewater management systems or the installation and operation of new ash and wastewater management systems. Compliance with the ELG rule is expected to require capital expenditures and increased operational costs primarily affecting the Company's coal-fired electric generation. Compliance applicability dates range from November 1, 2018 to December 31, 2023 with state environmental agencies incorporating specific applicability dates in the NPDES permitting process based on information provided for each waste stream. The EPA has committed to a new rulemaking that could potentially revise the limitations and applicability dates of the ELG rule. The EPA expects to finalize this rulemaking in 2020.

In 2015, the EPA and the U.S. Army Corps of Engineers (Corps) jointly published a final rule that revised the regulatory definition of waters of the United States (WOTUS) for all CWA programs. The rule significantly expanded the scope of federal jurisdiction over waterbodies (such as rivers, streams, and canals), which could impact new generation projects and permitting and reporting requirements associated with the installation, expansion, and maintenance of transmission and distribution projects. On July 27, 2017, the EPA and the Corps proposed to rescind the 2015 WOTUS rule. The WOTUS rule has been stayed by the U.S. Court of Appeals for the Sixth Circuit since late 2015, but on January 22, 2018, the U.S. Supreme Court determined that federal district courts have jurisdiction over the pending challenges to the rule. On February 6, 2018, the EPA and the Corps published a final rule delaying implementation of the 2015 WOTUS rule to 2020.

*Coal Combustion Residuals*

In 2015, the EPA finalized non-hazardous solid waste regulations for the disposal of CCR, including coal ash and gypsum, in landfills and surface impoundments (CCR units) at active generating power plants. The CCR Rule requires CCR units to be evaluated against a set of performance criteria and potentially closed if minimum criteria are not met. Closure of existing CCR units could require installation of equipment and infrastructure to manage CCR in accordance with the rule. The EPA has announced plans to reconsider certain portions of the CCR Rule by no later than December 2019, which could result in changes to deadlines and corrective action requirements.

The EPA's reconsideration of the CCR Rule is due in part to a legislative development that impacts the potential oversight role of state agencies. Under the Water Infrastructure Improvements for the Nation Act, which became law in 2016, states are allowed to establish permit programs for implementing the CCR Rule. The Georgia Department of Natural Resources has incorporated the requirements of the CCR Rule into its solid waste regulations, which established additional requirements for all of the Company's CCR units, and has requested that the EPA approve its state permitting program.

Based on cost estimates for closure and monitoring of ash ponds pursuant to the CCR Rule, the Company recorded an update to the AROs for each CCR unit in 2015. As further analysis is performed and closure details are developed, the Company will continue to periodically update these cost estimates as necessary. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information regarding the Company's AROs as of December 31, 2017 .

*Environmental Remediation*

The Company must comply with environmental laws and regulations governing the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up affected sites. The Company conducts studies to determine the extent of any required cleanup and has recognized the estimated costs to clean up known impacted sites in its financial statements. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Notes 1 and 3 to the financial statements under "Environmental Remediation Recovery" and "Environmental Matters – Environmental Remediation," respectively, for additional information.

***Global Climate Issues***

In 2015, the EPA published final rules limiting $CO_2$ emissions from new, modified, and reconstructed fossil fuel-fired electric generating units and guidelines for states to develop plans to meet EPA-mandated $CO_2$ emission performance standards for existing units (known as the Clean Power Plan or CPP). In February 2016, the U.S. Supreme Court granted a stay of the CPP, which will remain in effect through the resolution of litigation in the U.S. Court of Appeals for the District of Columbia challenging the legality of the CPP and any review by the U.S. Supreme Court. On March 28, 2017, the U.S. President signed an executive order directing agencies to review actions that potentially burden the development or use of domestically produced energy resources, including review of the CPP and other $CO_2$ emissions rules. On October 10, 2017, the EPA published a proposed rule to repeal the CPP and, on December 28, 2017, published an advanced notice of proposed rulemaking regarding a CPP replacement rule.

In 2015, parties to the United Nations Framework Convention on Climate Change, including the United States, adopted the Paris Agreement, which established a non-binding universal framework for addressing greenhouse gas (GHG) emissions based on nationally determined contributions. On June 1, 2017, the U.S. President announced that the United States would withdraw from the Paris Agreement and begin renegotiating its terms. The ultimate impact of this agreement or any renegotiated agreement depends on its implementation by participating countries.

The EPA's GHG reporting rule requires annual reporting of GHG emissions expressed in terms of metric tons of $CO_2$ equivalent emissions for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's

2016 GHG emissions were approximately 33 million metric tons of $CO_2$ equivalent. The preliminary estimate of the Company's 2017 GHG emissions on the same basis is approximately 30 million metric tons of $CO_2$ equivalent.

### FERC Matters

The Company has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies (including the Company) and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In 2015, the FERC issued an order finding that the traditional electric operating companies' (including the Company's) and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional electric operating companies (including the Company) and Southern Power filed a request for rehearing and filed their response with the FERC in 2015.

In December 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. On May 17, 2017, the FERC accepted the traditional electric operating companies' (including the Company's) and Southern Power's compliance filing accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

On October 25, 2017, the FERC issued an order in response to the traditional electric operating companies' (including the Company's) and Southern Power's June 29, 2017 triennial updated market power analysis. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show cause within 60 days why market-based rate authority should not be revoked in certain areas adjacent to the area presently under mitigation in accordance with the February 2, 2017 order or to provide a mitigation plan to further address market power concerns. On November 10, 2017, the traditional electric operating companies (including the Company) and Southern Power responded to the FERC and proposed to resolve matters by applying the alternative mitigation authorized by the February 2, 2017 order to the adjacent areas made the subject of the October 25, 2017 order.

The ultimate outcome of these matters cannot be determined at this time.

### Retail Regulatory Matters

The Company's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the Georgia PSC. The Company currently recovers its costs from the regulated retail business through the 2013 ARP, which includes traditional base tariff rates, Demand-Side Management (DSM) tariffs, ECCR tariffs, and Municipal Franchise Fee (MFF) tariffs. In addition, financing costs on certified project costs related to the construction of Plant Vogtle Units 3 and 4 are being collected through the NCCR tariff and fuel costs are collected through a separate fuel cost recovery tariff. See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

On January 16, 2018, the Georgia PSC approved the Company's sale of its natural gas lateral pipeline serving Plant McDonough Units 4 through 6 to Southern Natural Gas, L.L.C. (SNG) at net book value. Pursuant to this approval, legal transfer of the lateral pipeline is expected to occur in the fourth quarter 2018 and payment of $142 million is expected to occur in the first quarter 2020. Completion of this sale is contingent on certain conditions to be satisfied by SNG that include, among other things, expansion of the existing lateral pipeline. Southern Company Gas, an affiliate of the Company, owns a 50% equity interest in SNG. The ultimate outcome of this matter cannot be determined at this time; however, no material impact on the Company's financial statements is expected.

#### *Rate Plans*

Pursuant to the terms and conditions of a settlement agreement related to Southern Company's acquisition of Southern Company Gas approved by the Georgia PSC in April 2016, the 2013 ARP will continue in effect until December 31, 2019, and the Company will be required to file its next base rate case by July 1, 2019. Furthermore, through December 31, 2019, the Company and Atlanta

Gas Light Company each will retain their respective merger savings, net of transition costs, as defined in the settlement agreement; through December 31, 2022, such net merger savings applicable to each will be shared on a 60 / 40 basis with their respective customers; thereafter, all merger savings will be retained by customers. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information regarding the 2013 ARP.

In accordance with the 2013 ARP, the Georgia PSC approved increases to tariffs effective January 1, 2016 as follows: (1) traditional base tariff rates by approximately $49 million ; (2) ECCR tariff by approximately $75 million ; (3) DSM tariffs by approximately $3 million ; and (4) MFF tariff by approximately $13 million , for a total increase in base revenues of approximately $140 million . There were no changes to these tariffs in 2017.

Under the 2013 ARP, the Company's retail ROE is set at 10.95% and earnings are evaluated against a retail ROE range of 10.00% to 12.00% . Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by the Company. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. In 2015, the Company's retail ROE was within the allowed retail ROE range. In 2016, the Company's retail ROE exceeded 12.00% , and the Company will refund to retail customers approximately $44 million in 2018, as approved by the Georgia PSC on January 16, 2018. In 2017, the Company's retail ROE was within the allowed retail ROE range, subject to review and approval by the Georgia PSC.

On January 19, 2018, the Georgia PSC issued an order on the Tax Reform Legislation, which was amended on February 16, 2018 (Tax Order). In accordance with the Tax Order, the Company is required to submit its analysis of the Tax Reform Legislation and related recommendations to address the related impacts on the Company 's cost of service and annual revenue requirements by March 6, 2018. The ultimate outcome of this matter cannot be determined at this time.

***Integrated Resource Plan***

See "Environmental Matters" herein for additional information regarding proposed and final EPA rules and regulations, including revisions to ELG for steam electric power plants and additional regulations of CCR and $CO_2$ .

In July 2016, the Georgia PSC approved the Company's triennial Integrated Resource Plan (2016 IRP) including the decertification and retirement of Plant Mitchell Units 3, 4A, and 4B ( 217 MWs) and Plant Kraft Unit 1 ( 17 MWs) , as well as the decertification of the Intercession City unit ( 143 MWs total capacity) . In August 2016, the Plant Mitchell and Plant Kraft units were retired and the Company sold its 33% ownership interest in the Intercession City unit to Duke Energy Florida, LLC.

Additionally, the Georgia PSC approved the Company's environmental compliance strategy and related expenditures proposed in the 2016 IRP, including measures taken to comply with existing government-imposed environmental mandates, subject to limits on expenditures for Plant McIntosh Unit 1 and Plant Hammond Units 1 through 4.

The Georgia PSC approved the reclassification of the remaining net book value of Plant Mitchell Unit 3 and costs associated with materials and supplies remaining at the unit retirement date to a regulatory asset. Recovery of the unit's net book value will continue through December 31, 2019, as provided in the 2013 ARP. The timing of the recovery of the remaining balance of the unit's net book value as of December 31, 2019 and costs associated with materials and supplies remaining at the unit retirement date was deferred for consideration in the Company's 2019 base rate case.

The Georgia PSC also approved the Renewable Energy Development Initiative (REDI) to procure an additional 1,200 MWs of renewable resources primarily utilizing market-based prices established through a competitive bidding process with expected in-service dates between 2018 and 2021. Additionally, 200 MWs of self-build capacity for use by the Company was approved, as well as consideration for no more than 200 MWs of capacity as part of a renewable commercial and industrial program.

In 2017, the Company filed for and received certification for 510 MWs of REDI utility-scale PPAs for solar generation resources, which are expected to be in operation by the end of 2019. The Company also filed for and received approval to develop several solar generation projects to fulfill the approved self-build capacity.

In the 2016 IRP, the Georgia PSC also approved recovery of costs up to $99 million through June 30, 2019 to preserve nuclear generation as an option at a future generation site in Stewart County, Georgia. On March 7, 2017, the Georgia PSC approved the Company's decision to suspend work at the site due to changing economics, including lower load forecasts and fuel costs. The timing of recovery for costs incurred of approximately $50 million is expected to be determined by the Georgia PSC in a future rate case.

***Fuel Cost Recovery***

The Company has established fuel cost recovery rates approved by the Georgia PSC. In 2015, the Georgia PSC approved the Company's request to lower annual billings by approximately $350 million effective January 1, 2016. In May 2016, the Georgia PSC approved the Company's request to further lower annual billings under an interim fuel rider by approximately $313 million effective June 1, 2016, which expired on December 31, 2017. The Georgia PSC will review the Company's cumulative over or under recovered fuel balance no later than September 1, 2018 and evaluate the need to file a fuel case unless the Company deems it necessary to file a fuel case at an earlier time. The Company continues to be allowed to adjust its fuel cost recovery rates under an interim fuel rider prior to the next fuel case if the under recovered fuel balance exceeds $200 million .

The Company's fuel cost recovery mechanism includes costs associated with a natural gas hedging program, as revised and approved by the Georgia PSC, allowing the use of an array of derivative instruments within a 48 -month time horizon.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on the Company's revenues or net income, but will affect cash flow.

***Storm Damage Recovery***

The Company is accruing $30 million annually through December 31, 2019, as provided in the 2013 ARP, for incremental operating and maintenance costs of damage from major storms to its transmission and distribution facilities. Hurricanes Irma and Matthew caused significant damage to the Company's transmission and distribution facilities during September 2017 and October 2016, respectively. The incremental restoration costs related to these hurricanes deferred in the regulatory asset for storm damage totaled approximately $260 million . At December 31, 2017 , the total balance in the regulatory asset related to storm damage was $333 million . The rate of storm damage cost recovery is expected to be adjusted as part of the Company's next base rate case required to be filed by July 1, 2019. As a result of this regulatory treatment, costs related to storms are not expected to have a material impact on the Company's financial statements. See Note 1 to the financial statements under "Storm Damage Recovery" for additional information regarding the Company's storm damage reserve.

***Nuclear Construction***

*Vogtle 3 and 4 Agreement and EPC Contractor Bankruptcy*

In 2008, the Company, acting for itself and as agent for the Vogtle Owners, entered into the Vogtle 3 and 4 Agreement. Under the terms of the Vogtle 3 and 4 Agreement, the Vogtle Owners agreed to pay a purchase price subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. Under the Toshiba Guarantee, Toshiba guaranteed certain payment obligations of the EPC Contractor, including any liability of the EPC Contractor for abandonment of work. In the first quarter 2016, Westinghouse delivered to the Vogtle Owners a total of $920 million of letters of credit from financial institutions (Westinghouse Letters of Credit) to secure a portion of the EPC Contractor's potential obligations under the Vogtle 3 and 4 Agreement.

Subsequent to the EPC Contractor bankruptcy filing, a number of subcontractors to the EPC Contractor alleged non-payment by the EPC Contractor for amounts owed for work performed on Plant Vogtle Units 3 and 4. The Company, acting for itself and as agent for the Vogtle Owners, has taken actions to remove liens filed by these subcontractors through the posting of surety bonds. Related to such liens, certain subcontractors have filed, and additional subcontractors may file, actions against the EPC Contractor and the Vogtle Owners to preserve their payment rights with respect to such claims. All amounts associated with the removal of subcontractor liens and other EPC Contractor pre-petition accounts payable have been paid or accrued as of December 31, 2017.

On June 9, 2017, the Company and the other Vogtle Owners and Toshiba entered into the Guarantee Settlement Agreement. Pursuant to the Guarantee Settlement Agreement, Toshiba acknowledged the amount of its obligation was $3.68 billion (Guarantee Obligations), of which the Company's proportionate share was approximately $1.7 billion . The Guarantee Settlement Agreement provided for a schedule of payments for the Guarantee Obligations beginning in October 2017 and continuing through January 2021. Toshiba made the first three payments as scheduled. On December 8, 2017, the Company, the other Vogtle Owners, certain affiliates of the Municipal Electric Authority of Georgia (MEAG Power), and Toshiba entered into Amendment No. 1 to the Guarantee Settlement Agreement (Guarantee Settlement Agreement Amendment). The Guarantee Settlement Agreement Amendment provided that Toshiba's remaining payment obligations under the Guarantee Settlement Agreement were due and payable in full on December 15, 2017, which Toshiba satisfied on December 14, 2017. Pursuant to the Guarantee Settlement Agreement Amendment, Toshiba was deemed to be the owner of certain pre-petition bankruptcy claims of the Company, the other Vogtle Owners, and certain affiliates of MEAG Power against Westinghouse, and the Company and the other Vogtle Owners surrendered the Westinghouse Letters of Credit.

Additionally, on June 9, 2017, the Company, acting for itself and as agent for the other Vogtle Owners, and the EPC Contractor entered into the Vogtle Services Agreement, which was amended and restated on July 20, 2017. On July 20, 2017, the bankruptcy court approved the EPC Contractor's motion seeking authorization to (i) enter into the Vogtle Services Agreement, (ii) assume and assign to the Vogtle Owners certain project-related contracts, (iii) join the Vogtle Owners as counterparties to certain assumed project-related contracts, and (iv) reject the Vogtle 3 and 4 Agreement. The Vogtle Services Agreement, and the EPC Contractor's rejection of the Vogtle 3 and 4 Agreement, became effective upon approval by the DOE on July 27, 2017. The Vogtle Services Agreement will continue until the start-up and testing of Plant Vogtle Units 3 and 4 are complete and electricity is generated and sold from both units. The Vogtle Services Agreement is terminable by the Vogtle Owners upon 30 days' written notice.

Effective October 23, 2017, the Company, acting for itself and as agent for the other Vogtle Owners, entered into a construction completion agreement with Bechtel, whereby Bechtel will serve as the primary contractor for the remaining construction activities for Plant Vogtle Units 3 and 4 (Bechtel Agreement). Facility design and engineering remains the responsibility of the EPC Contractor under the Vogtle Services Agreement. The Bechtel Agreement is a cost reimbursable plus fee arrangement, whereby Bechtel will be reimbursed for actual costs plus a base fee and an at-risk fee, which is subject to adjustment based on Bechtel's performance against cost and schedule targets. Each Vogtle Owner is severally (not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to Bechtel under the Bechtel Agreement. The Vogtle Owners may terminate the Bechtel Agreement at any time for their convenience, provided that the Vogtle Owners will be required to pay amounts related to work performed prior to the termination (including the applicable portion of the base fee), certain termination-related costs, and, at certain stages of the work, the applicable portion of the at-risk fee. Bechtel may terminate the Bechtel Agreement under certain circumstances, including certain Vogtle Owner suspensions of work, certain breaches of the Bechtel Agreement by the Vogtle Owners, Vogtle Owner insolvency, and certain other events. Pursuant to the Loan Guarantee Agreement between the Company and the DOE, the Company is required to obtain the DOE's approval of the Bechtel Agreement prior to obtaining any further advances under the Loan Guarantee Agreement.

On November 2, 2017, the Vogtle Owners entered into an amendment to their joint ownership agreements for Plant Vogtle Units 3 and 4 (as amended, Vogtle Joint Ownership Agreements) to provide for, among other conditions, additional Vogtle Owner approval requirements. Pursuant to the Vogtle Joint Ownership Agreements, the holders of at least 90% of the ownership interests in Plant Vogtle Units 3 and 4 must vote to continue construction if certain adverse events occur, including (i) the bankruptcy of Toshiba; (ii) termination or rejection in bankruptcy of certain agreements, including the Vogtle Services Agreement or the Bechtel Agreement; (iii) the Georgia PSC or the Company determines that any of the Company's costs relating to the construction of Plant Vogtle Units 3 and 4 will not be recovered in retail rates because such costs are deemed unreasonable or imprudent; or (iv) an increase in the construction budget contained in the seventeenth VCM report of more than $1 billion or extension of the project schedule contained in the seventeenth VCM report of more than one year . In addition, pursuant to the Vogtle Joint Ownership Agreements, the required approval of holders of ownership interests in Plant Vogtle Units 3 and 4 is at least (i) 90% for a change of the primary construction contractor and (ii) 67% for material amendments to the Vogtle Services Agreement or agreements with Southern Nuclear or the primary construction contractor, including the Bechtel Agreement. The Vogtle Joint Ownership Agreements also confirm that the Vogtle Owners' sole recourse against the Company or Southern Nuclear for any action or inaction in connection with their performance as agent for the Vogtle Owners is limited to removal of the Company and/or Southern Nuclear as agent, except in cases of willful misconduct.

*Regulatory Matters*

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4 with a certified capital cost of $4.418 billion . In addition, in 2009 the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows the Company to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff up to the certified capital cost of $4.418 billion . As of December 31, 2017, the Company had recovered approximately $1.6 billion of financing costs. On January 30, 2018, the Company filed to decrease the NCCR tariff by approximately $50 million , effective April 1, 2018, pending Georgia PSC approval. The decrease reflects the payments received under the Guarantee Settlement Agreement, the Customer Refunds ordered by the Georgia PSC aggregating approximately $188 million , and the estimated effects of Tax Reform Legislation. The Customer Refunds were recognized as a regulatory liability as of December 31, 2017 and will be paid in three installments of $25 to each retail customer no later than the third quarter 2018.

The Company is required to file semi-annual VCM reports with the Georgia PSC by February 28 and August 31 each year. In October 2013, in connection with the eighth VCM report, the Georgia PSC approved a stipulation (2013 Stipulation) between the Company and the staff of the Georgia PSC to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate in accordance with the 2009 certification order until the completion of Plant Vogtle Unit 3, or earlier if deemed appropriate by the Georgia PSC and the Company.

On December 20, 2016, the Georgia PSC voted to approve a settlement agreement (Vogtle Cost Settlement Agreement) resolving certain prudency matters in connection with the fifteenth VCM report. On December 21, 2017, the Georgia PSC voted to approve (and issued its related order on January 11, 2018) certain recommendations made by the Company in the seventeenth VCM report and modifying the Vogtle Cost Settlement Agreement. The Vogtle Cost Settlement Agreement, as modified by the January 11, 2018 order, resolved the following regulatory matters related to Plant Vogtle Units 3 and 4: (i) none of the $3.3 billion of costs incurred through December 31, 2015 and reflected in the fourteenth VCM report should be disallowed from rate base on the basis of imprudence; (ii) the Contractor Settlement Agreement was reasonable and prudent and none of the amounts paid pursuant to the Contractor Settlement Agreement should be disallowed from rate base on the basis of imprudence; (iii) (a) capital costs incurred up to $5.680 billion would be presumed to be reasonable and prudent with the burden of proof on any party challenging such costs, (b) the Company would have the burden to show that any capital costs above $5.680 billion were prudent, and (c) a revised capital cost forecast of $7.3 billion (after reflecting the impact of payments received under the Guarantee Settlement Agreement and Customer Refunds) is found reasonable; (iv) construction of Plant Vogtle Units 3 and 4 should be completed, with Southern Nuclear serving as project manager and Bechtel as primary contractor; (v) approved and deemed reasonable the Company's revised schedule placing Plant Vogtle Units 3 and 4 in service in November 2021 and November 2022, respectively; (vi) confirmed that the revised cost forecast does not represent a cost cap and that prudence decisions on cost recovery will be made at a later date, consistent with applicable Georgia law; (vii) reduced the ROE used to calculate the NCCR tariff (a) from 10.95% (the ROE rate setting point authorized by the Georgia PSC in the 2013 ARP) to 10.00% effective January 1, 2016, (b) from 10.00% to 8.30% , effective January 1, 2020, and (c) from 8.30% to 5.30% , effective January 1, 2021 (provided that the ROE in no case will be less than the Company's average cost of long-term debt); (viii) reduced the ROE used for AFUDC equity for Plant Vogtle Units 3 and 4 from 10.00% to the Company's average cost of long-term debt, effective January 1, 2018; and (ix) agreed that upon Unit 3 reaching commercial operation, retail base rates would be adjusted to include carrying costs on those capital costs deemed prudent in the Vogtle Cost Settlement Agreement. The January 11, 2018 order also stated that if Plant Vogtle Units 3 and 4 are not commercially operational by June 1, 2021 and June 1, 2022, respectively, the ROE used to calculate the NCCR tariff will be further reduced by 10 basis points each month (but not lower than the Company's average cost of long-term debt) until the respective unit is commercially operational. The ROE reductions negatively impacted earnings by approximately $20 million in 2016 and $25 million in 2017 and are estimated to have negative earnings impacts of approximately $120 million in 2018 and an aggregate of $585 million from 2019 to 2022. In its January 11, 2018 order, the Georgia PSC stated if other certain conditions and assumptions upon which the Company's seventeenth VCM report are based do not materialize, both the Company and the Georgia PSC reserve the right to reconsider the decision to continue construction.

On February 12, 2018, Georgia Interfaith Power & Light, Inc. and Partnership for Southern Equity, Inc. filed a petition appealing the Georgia PSC's January 11, 2018 order with the Fulton County Superior Court. The Company believes the appeal has no merit; however, an adverse outcome in this appeal could have a material impact on the Company's results of operations, financial condition, and liquidity.

The IRS allocated PTCs to each of Plant Vogtle Units 3 and 4, which originally required the applicable unit to be placed in service before 2021. Under the Bipartisan Budget Act of 2018, Plant Vogtle Units 3 and 4 continue to qualify for PTCs. The nominal value of the Company's portion of the PTCs is approximately $500 million per unit.

In its January 11, 2018 order, the Georgia PSC also approved $542 million of capital costs incurred during the seventeenth VCM reporting period (January 1, 2017 to June 30, 2017). The Georgia PSC has approved seventeen VCM reports covering the periods through June 30, 2017 , including total construction capital costs incurred through that date of $4.4 billion . The Company expects to file its eighteenth VCM report on February 28, 2018 requesting approval of approximately $450 million of construction capital costs (before payments received under the Guarantee Settlement Agreement and the Customer Refunds) incurred from July 1, 2017 through December 31, 2017 . The Company's CWIP balance for Plant Vogtle Units 3 and 4 was approximately $4.8 billion as of December 31, 2017 , or $3.3 billion net of payments received under the Guarantee Settlement Agreement and the Customer Refunds.

The ultimate outcome of these matters cannot be determined at this time.

*Cost and Schedule*

The Company's approximate proportionate share of the remaining estimated capital cost to complete Plant Vogtle Units 3 and 4 with in service dates of November 2021 and November 2022, respectively, is as follows:

| | | *(in billions)* |
|---|---|---|
| Project capital cost forecast | $ | 7.3 |
| Net investment as of December 31, 2017 | | (3.4) |
| **Remaining estimate to complete** | **$** | **3.9** |

Note: Excludes financing costs capitalized through AFUDC and is net of payments received under the Guarantee Settlement Agreement and the Customer Refunds.

The Company estimates that its financing costs for construction of Plant Vogtle Units 3 and 4 will total approximately $3.1 billion , of which $1.6 billion had been incurred through December 31, 2017 .

As construction continues, challenges with management of contractors, subcontractors, and vendors, labor productivity and availability, fabrication, delivery, assembly, and installation of plant systems, structures, and components (some of which are based on new technology and have not yet operated in the global nuclear industry at this scale), or other issues could arise and change the projected schedule and estimated cost.

There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4 at the federal and state level and additional challenges may arise. Processes are in place that are designed to assure compliance with the requirements specified in the Westinghouse Design Control Document and the combined construction and operating licenses, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance matters, including the timely resolution of Inspections, Tests, Analyses, and Acceptance Criteria and the related approvals by the NRC, may arise, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs.

The ultimate outcome of these matters cannot be determined at this time.

*Other Matters*

As of December 31, 2017 , the Company had borrowed $2.6 billion related to Plant Vogtle Units 3 and 4 costs through the Loan Guarantee Agreement and a multi-advance credit facility among the Company, the DOE, and the FFB, which provides for borrowings of up to $3.46 billion , subject to the satisfaction of certain conditions. On September 28, 2017, the DOE issued a conditional commitment to the Company for up to approximately $1.67 billion in additional guaranteed loans under the Loan Guarantee Agreement. This conditional commitment expires on June 30, 2018, subject to any further extension approved by the DOE. Final approval and issuance of these additional loan guarantees by the DOE cannot be assured and are subject to the negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information, including applicable covenants, events of default, mandatory prepayment events, and conditions to borrowing.

The ultimate outcome of these matters cannot be determined at this time.

**Income Tax Matters**

***Federal Tax Reform Legislation***

On December 22, 2017, the Tax Reform Legislation was signed into law and became effective on January 1, 2018. The Tax Reform Legislation, among other things, reduces the federal corporate income tax rate to 21%, retains normalization provisions for public utility property and existing renewable energy incentives, and repeals the corporate alternative minimum tax.

Regulated utility businesses can continue deducting all business interest expense and are not eligible for bonus depreciation on capital assets acquired and placed in service after September 27, 2017. Projects with binding contracts before September 28, 2017 and placed in service after September 27, 2017 remain eligible for bonus depreciation under the Protecting Americans from Tax Hikes (PATH) Act.

In addition, under the Tax Reform Legislation, net operating losses (NOLs) generated after December 31, 2017 can no longer be carried back to previous tax years but can be carried forward indefinitely, with utilization limited to 80% of taxable income of the subsequent tax year. The projected reduction of Southern Company's consolidated income tax liability resulting from the tax rate reduction also delays the expected utilization of existing tax credit carryforwards.

For the year ended December 31, 2017, implementation of the Tax Reform Legislation resulted in an estimated net tax benefit of $8 million, a $150 million decrease in regulatory assets, and a $3.1 billion increase in regulatory liabilities, primarily due to the impact of the reduction of the corporate income tax rate on deferred tax assets and liabilities.

The Tax Reform Legislation is subject to further interpretation and guidance from the IRS, as well as each respective state's adoption. In addition, the regulatory treatment of certain impacts of the Tax Reform Legislation is subject to the discretion of the FERC and the Georgia PSC. On January 31, 2018, SCS, on behalf of the traditional electric operating companies (including the Company), filed with the FERC a reduction to the Company's open access transmission tariff charge for 2018 to reflect the revised federal corporate tax rate. See Note 3 to the financial statements under "Regulatory Matters" for additional information regarding the Company's rate filing to reflect the impacts of the Tax Reform Legislation.

See FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein and Note 5 to the financial statements under "Current and Deferred Income Taxes" for additional information.

The ultimate outcome of these matters cannot be determined at this time.

***Bonus Depreciation***

Under the Tax Reform Legislation, projects with binding contracts prior to September 28, 2017 and placed in service after September 27, 2017 remain eligible for bonus depreciation under the PATH Act. The PATH Act allowed for 50% bonus depreciation for 2015 through 2017, 40% bonus depreciation for 2018, and 30% bonus depreciation for 2019 and certain long-lived assets placed in service in 2020. Based on provisional estimates, bonus depreciation is expected to result in positive cash flows of approximately $270 million for the 2017 tax year and approximately $120 million for the 2018 tax year. Should Southern Company have a NOL in 2018, all of these cash flows may not be fully realized in 2018. See Note 5 to the financial statements under "Current and Deferred Income Taxes" for additional information.

**Other Matters**

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as standards for air, water, land, and protection of other natural resources, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by $CO_2$ and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters.

The ultimate outcome of such pending or potential litigation or regulatory matters cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

The Company regularly reviews its business to transform and modernize. Primarily in response to changing customer expectations and payment patterns, including electronic payments and alternative payment locations, and ongoing efforts to increase overall operating efficiencies, in 2017, the Company initiated the closure of its remaining payment offices and an employee attrition plan affecting approximately 300 positions. Charges associated with these activities did not have a material impact on the Company's results of operations, financial position, or cash flows. The efficiencies gained are expected to place downward pressure on operating costs in 2018.

## ACCOUNTING POLICIES

### Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

***Utility Regulation***

The Company is subject to retail regulation by the Georgia PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, AROs, and pension and other postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and any requirement to refund these regulatory liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

***Federal Tax Reform Legislation***

Following the enactment of Tax Reform Legislation, the SEC staff issued Staff Accounting Bulletin 118 – "Income Tax Accounting Implications of the Tax Cuts and Jobs Act" (SAB 118), which provides for a measurement period of up to one year from the enactment date to complete accounting under GAAP for the tax effects of the legislation. Due to the complex and comprehensive nature of the enacted tax law changes, and their application under GAAP, the Company considers all amounts recorded in the financial statements as a result of Tax Reform Legislation to be "provisional" as discussed in SAB 118 and subject to revision. The Company is awaiting additional guidance from industry and income tax authorities in order to finalize its accounting. The ultimate impact of Tax Reform Legislation on deferred income tax assets and liabilities and the related regulatory assets and liabilities cannot be determined at this time. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation " herein and Notes 3 and 5 to the financial statements under "Retail Regulatory Matters – Rate Plans" and "Current and Deferred Income Taxes," respectively, for additional information.

***Asset Retirement Obligations***

AROs are computed as the fair value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities.

The liability for AROs primarily relates to the decommissioning of the Company's nuclear facilities, which include the Company's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2, and facilities that are subject to the CCR Rule, principally ash ponds. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, including the disposal of polychlorinated biphenyls in certain transformers; leasehold improvements; equipment on customer property; and property associated with the Company's rail lines and natural gas pipelines. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO.

The Company previously recorded AROs as a result of state requirements in Georgia which closely align with the requirements of the CCR Rule discussed above. The cost estimates are based on information using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure. As further analysis is performed and closure details are developed, the Company will continue to periodically update these cost estimates as necessary. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations – Coal Combustion Residuals" herein and Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" and "Nuclear Decommissioning" for additional information.

Given the significant judgment involved in estimating AROs, the Company considers the liabilities for AROs to be critical accounting estimates.

***Pension and Other Postretirement Benefits***

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on pension and other postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. For purposes of determining its liability related to the pension and other postretirement benefit plans, the Company discounts the future related cash flows using a single-point discount rate for each plan developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments. For 2015 and prior years, the Company computed the interest cost component of its net periodic pension and other postretirement benefit plan expense using the same single-point discount rate. Beginning in 2016, the Company adopted a full yield curve approach for calculating the interest cost component whereby the discount rate for each year is applied to the liability for that specific year. As a result, the interest cost component of net periodic pension and other postretirement benefit plan expense decreased by approximately $35 million in 2016.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in an $11 million or less change in total annual benefit expense and a $172 million or less change in projected obligations.

See Note 2 to the financial statements for additional information regarding pension and other postretirement benefits.

***Contingent Obligations***

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's results of operations, cash flows, or financial condition.

**Recently Issued Accounting Standards**

***Revenue***

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers* (ASC 606), replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the new standard is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

Most of the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term , as well as longer-term contractual commitments, including PPAs.

The Company has completed the evaluation of all revenue streams and determined that the adoption of ASC 606 will not change the current timing of revenue recognition for such transactions. Some revenue arrangements, such as energy-related derivatives, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed separately from revenues under ASC 606. The Company has concluded contributions in aid of construction are not in scope for ASC 606 and will continue to be accounted for as an offset to property, plant, and equipment.

The new standard is effective for reporting periods beginning after December 15, 2017. The Company applied the modified retrospective method of adoption effective January 1, 2018. The Company also utilized practical expedients which allowed it to apply the standard to open contracts at the date of adoption and to reflect the aggregate effect of all modifications when identifying performance obligations and allocating the transaction price for contracts modified before the effective date. Under the modified retrospective method of adoption, prior year reported results are not restated; however, a cumulative-effect adjustment to retained earnings at January 1, 2018 is recorded. In addition, quarterly disclosures will include comparative information on 2018 financial statement line items under current guidance. The adoption of ASC 606 did not result in a cumulative-effect adjustment .

***Leases***

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged . ASU 2016-02 is effective for fiscal years beginning after December 15, 2018 and the Company will adopt the new standard effective January 1, 2019.

The Company is currently implementing an information technology system along with the related changes to internal controls and accounting policies that will support the accounting for leases under ASU 2016-02. In addition, the Company has substantially completed a detailed inventory and analysis of its leases. In terms of rental charges and duration of contracts, the most significant leases relate to PPAs and cellular towers where the Company is the lessee and to outdoor lighting where the Company is the lessor. The Company is currently analyzing pole attachment agreements, and a lease determination has not been made at this time. While the Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

***Other***

On March 10, 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017-07). ASU 2017-07 requires that an employer report the service cost component in the same line item or items as other compensation costs and requires the other components of net periodic pension and postretirement benefit costs to be separately presented in the income statement outside of income from operations. Additionally, only the service cost component is eligible for capitalization, when applicable. However, all cost components remain eligible for capitalization under FERC regulations. ASU 2017-07 will be applied retrospectively for the presentation of the service cost component and the other components of net periodic pension and postretirement benefit costs in the income statement. The capitalization of only the service cost component of net periodic pension and postretirement benefit costs in assets will be applied on a prospective basis. ASU 2017-07 is effective for periods beginning after December 15, 2017. The presentation changes required for net periodic pension and postretirement benefit costs will result in a decrease in the Company's operating income and an increase in other income for 2016 and 2017 and are expected to result in a decrease in operating income and an increase in other income for 2018. The Company adopted ASU 2017-07 effective January 1, 2018 with no material impact on its financial statements.

On August 28, 2017, the FASB issued ASU No. 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities* (ASU 2017-12), amending the hedge accounting recognition and presentation requirements. ASU 2017-12 makes more financial and non-financial hedging strategies eligible for hedge accounting, amends the related presentation and disclosure requirements, and simplifies hedge effectiveness assessment requirements. ASU 2017-12 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

## FINANCIAL CONDITION AND LIQUIDITY

### Overview

The Company's financial condition remained stable at December 31, 2017 . The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to build new generation facilities, including Plant Vogtle Units 3 and 4, to maintain existing generation facilities, to comply with environmental regulations including adding environmental modifications to existing generating units, to expand and improve transmission and distribution facilities, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2018 through 2020 , the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. The Company plans to finance future cash needs in excess of its operating cash flows primarily through external securities issuances, equity contributions from Southern Company, borrowings from financial institutions, and borrowings through the FFB. The Company plans to use commercial paper to manage seasonal variations in operating cash flows and for other working capital needs. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan and nuclear decommissioning trust funds increased in value as of December 31, 2017 as compared to December 31, 2016 . No contributions to the qualified pension plan were made for the year ended December 31, 2017 and no mandatory contributions to the qualified pension plan are anticipated during 2018 . The Company also funded approximately $5 million to its nuclear decommissioning trust funds in 2017 . See "Contractual Obligations" herein and Notes 1 and 2 to the financial statements under "Nuclear Decommissioning" and "Pension Plans," respectively, for additional information.

Net cash provided from operating activities totaled $1.9 billion in 2017 , a decrease of $513 million from 2016 , primarily due to the timing of vendor payments and increases in under-recovered fuel costs and prepaid federal income taxes, partially offset by a decrease in voluntary contributions to the qualified pension plan. Net cash provided from operating activities totaled $2.4 billion in 2016 , a decrease of $92 million from 2015 , primarily due to the voluntary contribution to the qualified pension plan in 2016, partially offset by the timing of vendor payments. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation " herein and Note 5 to the financial statements for additional information regarding federal income taxes.

Net cash used for investing activities totaled $0.9 billion , $2.3 billion , and $1.9 billion in 2017 , 2016 , and 2015 , respectively, due to gross property additions primarily related to installation of equipment to comply with environmental standards; construction of generation, transmission, and distribution facilities including Plant Vogtle Units 3 and 4, partially offset in 2017 by $1.7 billion in payments received under the Guarantee Settlement Agreement; and purchases of nuclear fuel. The majority of funds needed for gross property additions for the last several years has been provided from operating activities, capital contributions from Southern Company, and the issuance of debt. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Nuclear Construction" herein for additional information on the Guarantee Settlement Agreement and construction of Plant Vogtle Units 3 and 4.

Net cash used for financing activities totaled $151 million , $142 million , and $530 million for 2017 , 2016 , and 2015 , respectively. The increase in cash used in 2017 compared to 2016 was primarily due to a decrease in notes payable, a decrease in borrowings from the FFB for construction of Plant Vogtle Units 3 and 4, and the redemption of all outstanding shares of the Company's preferred and preference stock, partially offset by higher issuances of senior notes and junior subordinated notes and a decrease in maturities of senior notes. The decrease in cash used in 2016 compared to 2015 was primarily due to higher capital contributions from Southern Company, a decrease in redemptions and maturities of senior notes, and an increase in short-term debt, partially offset by higher common stock dividends and a decrease in borrowings from the FFB for construction of Plant Vogtle Units 3 and 4. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes in 2017 included an increase of $3.1 billion in deferred credits related to income taxes and a decrease of $2.8 billion in accumulated deferred income taxes primarily resulting from the impacts of Tax Reform Legislation; an increase in property, plant, and equipment of $2.0 billion to comply with environmental standards and the construction of generation, transmission, and distribution facilities, partially offset by payments received under the Guarantee Settlement Agreement of $1.7 billion , net of joint owner portion; and an increase of $1.2 billion in long-term debt primarily due to issuances of senior notes and junior subordinated notes. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation " herein and Note 5 to the financial statements for additional information on Tax Reform Legislation and Note 3 to the financial statements under "Retail Regulatory Matters – Nuclear Construction" for additional information on the Guarantee Settlement Agreement.

The Company's ratio of common equity to total capitalization plus short-term debt was 49.7% at December 31, 2017 and 50.0% at December 31, 2016 . See Note 6 to the financial statements for additional information.

**Sources of Capital**

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, external security issuances, borrowings from financial institutions, equity contributions from Southern Company, and borrowings from the FFB. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approvals, prevailing market conditions, and other factors.

In 2014, the Company entered into the Loan Guarantee Agreement with the DOE, under which the proceeds of borrowings may be used to reimburse the Company for Eligible Project Costs incurred in connection with its construction of Plant Vogtle Units 3 and 4. Under the Loan Guarantee Agreement, the DOE agreed to guarantee borrowings of up to $3.46 billion (not to exceed 70% of Eligible Project Costs) to be made by the Company under a multi-advance credit facility (FFB Credit Facility) among the Company, the DOE, and the FFB. As of December 31, 2017 , the Company had borrowed $2.6 billion under the FFB Credit Facility. On July 27, 2017, the Company entered into an amendment to the Loan Guarantee Agreement, which provides that further advances are conditioned upon the DOE's approval of any agreements entered into in replacement of the Vogtle 3 and 4 Agreement and satisfaction of certain other conditions.

On September 28, 2017, the DOE issued a conditional commitment to the Company for up to approximately $1.67 billion of additional guaranteed loans under the Loan Guarantee Agreement. This conditional commitment expires on June 30, 2018, subject to any further extension approved by the DOE. Final approval and issuance of these additional loan guarantees by the DOE cannot be assured and are subject to the negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information regarding the Loan Guarantee Agreement, including applicable covenants, events of default, mandatory prepayment events, and additional conditions to borrowing. Also see Note 3 to the financial statements under "Retail Regulatory Matters – Nuclear Construction" for additional information regarding Plant Vogtle Units 3 and 4.

The issuance of long-term securities by the Company is subject to the approval of the Georgia PSC. In addition, the issuance of short-term debt securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended. The amounts of securities authorized by the Georgia PSC and the FERC are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company in the Southern Company system.

At December 31, 2017 , the Company's current liabilities exceeded current assets by $521 million . The Company's current liabilities frequently exceed current assets because of scheduled maturities of long-term debt and the periodic use of short-term debt as a funding source, as well as significant seasonal fluctuations in cash needs.

The Company intends to utilize operating cash flows, external security issuances, borrowings from financial institutions, equity contributions from Southern Company, and borrowings from the FFB to fund its short-term capital needs. The Company has substantial cash flow from operating activities and access to the capital markets and financial institutions to meet short-term liquidity needs.

At December 31, 2017 , the Company had approximately $852 million of cash and cash equivalents. A committed credit arrangement with banks at December 31, 2017 was $1.75 billion of which $1.73 billion was unused. In May 2017, the Company amended its multi-year credit arrangement which, among other things, extended the maturity date from 2020 to 2022.

This bank credit arrangement, as well as the Company's term loan arrangements, contains a covenant that limits debt levels and contains a cross-acceleration provision to other indebtedness (including guarantee obligations) of the Company. Such cross-acceleration provision to other indebtedness would trigger an event of default if the Company defaulted on indebtedness, the payment of which was then accelerated. At December 31, 2017 , the Company was in compliance with this covenant. This bank credit arrangement does not contain a material adverse change clause at the time of borrowing.

Subject to applicable market conditions, the Company expects to renew or replace this credit arrangement, as needed, prior to expiration. In connection therewith, the Company may extend the maturity date and/or increase or decrease the lending commitments thereunder.

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

A portion of the unused credit with banks is allocated to provide liquidity support to the Company's pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2017 was $550 million as compared to $868 million at December 31, 2016 . In addition, at December 31, 2017 , the Company had $469 million of pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional electric operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each traditional electric operating company under these arrangements are several and there is no cross-affiliate credit support. Short-term borrowings are included in notes payable in the balance sheets.

Details of short-term borrowings were as follows:

| | Short-term Debt at the End of the Period | | Short-term Debt During the Period (*) | | |
|---|---|---|---|---|---|
| | Amount Outstanding | Weighted Average Interest Rate | Average Amount Outstanding | Weighted Average Interest Rate | Maximum Amount Outstanding |
| | *(in millions)* | | *(in millions)* | | *(in millions)* |
| **December 31, 2017:** | | | | | |
| Commercial paper | **$ —** | **—%** | **$ 135** | **1.3%** | **$ 760** |
| Short-term bank debt | **150** | **2.2%** | **292** | **2.0%** | **800** |
| Total | **$ 150** | **2.2%** | **$ 427** | **1.8%** | |
| **December 31, 2016:** | | | | | |
| Commercial paper | $ 392 | 1.1% | $ 87 | 0.8% | $ 443 |
| **December 31, 2015:** | | | | | |
| Commercial paper | $ 158 | 0.6% | $ 234 | 0.3% | $ 678 |
| Short-term bank debt | — | —% | 62 | 0.8% | 250 |
| Total | $ 158 | 0.6% | $ 296 | 0.4% | |

(*) Average and maximum amounts are based upon daily balances during the 12-month periods ended December 31, 2017 , 2016 , and 2015 .

The Company believes the need for working capital can be adequately met by utilizing the commercial paper program, lines of credit, short-term bank notes, and operating cash flows.

**Financing Activities**

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

***Senior Notes***

In March 2017, the Company issued $450 million aggregate principal amount of Series 2017A 2.00% Senior Notes due March 30, 2020 and $400 million aggregate principal amount of Series 2017B 3.25% Senior Notes due March 30, 2027. The proceeds were used to repay a portion of the Company's short-term indebtedness and for general corporate purposes, including the Company's continuous construction program.

In June 2017, the Company repaid at maturity $450 million aggregate principal amount of Series 2007B 5.70% Senior Notes.

In August 2017, the Company issued $500 million aggregate principal amount of Series 2017C 2.00% Senior Notes due September 8, 2020. The proceeds were used to repay the Company's $50 million short-term floating rate bank loan due December 1, 2017 and outstanding commercial paper borrowings and for general corporate purposes.

***Junior Subordinated Notes***

In September 2017, the Company issued $270 million aggregate principal amount of Series 2017A 5.00% Junior Subordinated Notes due October 1, 2077. The proceeds were used to redeem all 1.8 million shares ($45 million aggregate liquidation amount) of the Company's 6.125% Series Class A Preferred Stock and 2.25 million shares ($225 million aggregate liquidation amount) of the Company's 6.50% Series 2007A Preference Stock.

***Pollution Control Revenue Bonds***

In April 2017, the Company purchased and held $27 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), Fifth Series 1995. In October 2017, the Company remarketed these bonds to the public.

In August 2017, the Company purchased and held $38 million aggregate principal amount of Development Authority of Bartow County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Bowen Project), First Series 1997. In October 2017, the Company remarketed these bonds to the public.

***Other***

In June 2017, the Company entered into three floating rate bank loans in aggregate principal amounts of $50 million, $150 million, and $100 million, with maturity dates of December 1, 2017, May 31, 2018, and June 28, 2018, respectively, bearing interest based on one-month LIBOR. Also in June 2017, the Company borrowed $500 million pursuant to a short-term uncommitted bank credit arrangement, which bears interest at a rate agreed upon by the Company and the bank from time to time and is payable on no less than 30 days' demand by the bank. The proceeds from these bank loans were used to repay a portion of the Company's existing indebtedness and for working capital and other general corporate purposes, including the Company's continuous construction program.

In August 2017, the Company repaid $250 million of the $500 million aggregate principal amount outstanding pursuant to its uncommitted bank credit arrangement. Also in August 2017, the Company amended its $100 million floating rate bank loan to extend the maturity date from June 28, 2018 to October 26, 2018.

In December 2017, the Company repaid the remaining $250 million aggregate principal amount outstanding pursuant to its uncommitted bank credit arrangement.

Subsequent to December 31, 2017 , the Company repaid its outstanding $150 million and $100 million floating rate bank loans due May 31, 2018 and October 26, 2018, respectively.

**Credit Rating Risk**

At December 31, 2017 , the Company did not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, energy price risk management, transmission, interest rate management, and construction of new generation at Plant Vogtle Units 3 and 4.

The maximum potential collateral requirements under these contracts at December 31, 2017 were as follows:

| Credit Ratings | Maximum Potential Collateral Requirements |
|---|---|
| | *(in millions)* |
| At BBB- and/or Baa3 | $ 87 |
| Below BBB- and/or Baa3 | $ 1,055 |

Included in these amounts are certain agreements that could require collateral in the event that the Company or Alabama Power has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact the ability of the Company to access capital markets and would be likely to impact the cost at which it does so.

On March 20, 2017, Moody's revised its rating outlook for the Company from stable to negative.

On March 24, 2017, S&P revised its consolidated credit rating outlook for Southern Company and its subsidiaries (including the Company) from stable to negative.

On March 30, 2017, Fitch placed the ratings of the Company on rating watch negative.

While it is unclear how the credit rating agencies, the FERC, and the Georgia PSC may respond to the Tax Reform Legislation, certain financial metrics, such as the funds from operations to debt percentage, used by the credit rating agencies to assess Southern Company and its subsidiaries, including the Company, may be negatively impacted. Absent actions by Southern Company and its subsidiaries, including the Company, to mitigate the resulting impacts, which, among other alternatives, could include adjusting capital structure and/or monetizing regulatory assets, the Company's credit ratings could be negatively affected. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information.

**MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)**
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**Market Price Risk**

Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives designated as hedges. The weighted average interest rate on $1.9 billion of long-term variable interest rate exposure at December 31, 2017 was 2.66%. If the Company sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would affect annualized interest expense by approximately $19 million at December 31, 2017 . See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases. The Company continues to manage a fuel-hedging program implemented per the guidelines of the Georgia PSC. The Company had no material change in market risk exposure for the year ended December 31, 2017 when compared to the December 31, 2016 reporting period.

The changes in fair value of energy-related derivative contracts are substantially attributable to both the volume and the price of natural gas. For the years ended December 31, the changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, were as follows:

| | **2017 Changes** | 2016 Changes |
|---|---|---|
| | Fair Value | |
| | *(in millions)* | |
| **Contracts outstanding at the beginning of the period, assets (liabilities), net** | **$ 36** | $ (13) |
| **Contracts realized or settled:** | | |
| Swaps realized or settled | **(13)** | (2) |
| Options realized or settled | **(1)** | 11 |
| **Current period changes (*) :** | | |
| Swaps | **(28)** | 31 |
| Options | **(7)** | 9 |
| **Contracts outstanding at the end of the period, assets (liabilities), net** | **$ (13)** | $ 36 |

(*) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The net hedge volumes of energy-related derivative contracts for the years ended December 31 were as follows:

| | **2017** | 2016 |
|---|---|---|
| | mmBtu Volume | |
| | *(in millions)* | |
| Commodity – Natural gas swaps | **146** | 128 |
| Commodity – Natural gas options | **17** | 27 |
| Total hedge volume | **163** | 155 |

The weighted average swap contract cost above market prices was approximately $0.08 per mmBtu as of December 31, 2017 . The weighted average swap contract cost below market prices was approximately $0.23 per mmBtu as of December 31, 2016 . The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. All natural gas hedge gains and losses are recovered through the Company's fuel cost recovery mechanism.

At December 31, 2017 and 2016 , substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were related to the Company's fuel-hedging program, which had a time horizon up to 48 months. Hedging gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery mechanism. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2 of the fair value hierarchy. See Note 10 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2017 were as follows:

| | Fair Value Measurements December 31, 2017 | | |
|---|---|---|---|
| | Total | Maturity | |
| | Fair Value | Year 1 | Years 2&3 |
| | | *(in millions)* | |
| Level 1 | $ — | $ — | $ — |
| Level 2 | (13) | (7) | (6) |
| Level 3 | — | — | — |
| Fair value of contracts outstanding at end of period | $ (13) | $ (7) | $ (6) |

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related and interest rate derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

**Capital Requirements and Contractual Obligations**

The construction program of the Company is currently estimated to total $3.3 billion for 2018 , $3.2 billion for 2019 , $2.7 billion for 2020 , $2.4 billion for 2021 , and $2.2 billion for 2022 . These amounts include expenditures of approximately $1.2 billion, $1.0 billion, $0.9 billion, $0.7 billion, and $0.4 billion for the construction of Plant Vogtle Units 3 and 4 in 2018 , 2019 , 2020 , 2021 , and 2022, respectively. These amounts also include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under LTSAs. Estimated capital expenditures to comply with environmental laws and regulations included in these amounts are $0.5 billion , $0.1 billion , $0.2 billion , $0.2 billion , and $0.2 billion for 2018 , 2019 , 2020 , 2021 , and 2022 , respectively. These estimated expenditures do not include any potential compliance costs associated with the regulation of $CO_2$ emissions from fossil fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations" and "– Global Climate Issues" herein for additional information.

The Company also anticipates costs associated with closure and monitoring of ash ponds in accordance with the CCR Rule, which are reflected in the Company's ARO liabilities. These costs, which could change as the Company continues to refine its assumptions underlying the cost estimates and evaluate the method and timing of compliance activities, are estimated to be $0.2 billion per year for 2018 through 2020 and $0.3 billion per year for 2021 and 2022. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental laws and regulations; the outcome of any legal challenges to environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing generating units, to meet regulatory requirements; changes in FERC rules and regulations; Georgia PSC approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. The construction program also includes Plant Vogtle Units 3 and 4, which may be subject to revised cost estimates during construction. The ability to control costs and avoid cost overruns during the development, construction, and operation of new facilities is subject to a number of factors, including, but not limited to, changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction, operating, or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance. See Note 3 to the financial statements under "Retail Regulatory Matters – Nuclear Construction" for information regarding additional factors that may impact construction expenditures.

As a result of requirements by the NRC, the Company has established external trust funds for nuclear decommissioning costs. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the Georgia PSC and the FERC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, leases, other purchase commitments, and trusts are detailed in the contractual obligations table that follows. See Notes 1, 2, 6, 7, and 11 to the financial statements for additional information.

**MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)**
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**Contractual Obligations**

Contractual obligations at December 31, 2017 were as follows:

| | 2018 | 2019- 2020 | 2021- 2022 | After 2022 | Total |
|---|---|---|---|---|---|
| | | | *(in millions)* | | |
| Long-term debt [(a)] — | | | | | |
| Principal | $ 850 | $ 1,494 | $ 879 | $ 8,693 | $ 11,916 |
| Interest | 419 | 760 | 688 | 5,786 | 7,653 |
| Financial derivative obligations [(b)] | 10 | 10 | — | — | 20 |
| Operating leases [(c)] | 24 | 42 | 31 | 44 | 141 |
| Capital leases [(c)] | 9 | 16 | — | — | 25 |
| Purchase commitments — | | | | | |
| Capital [(d)] | 3,080 | 5,508 | 4,006 | — | 12,594 |
| Fuel [(e)] | 1,238 | 1,245 | 818 | 5,075 | 8,376 |
| Purchased power [(f)] | 318 | 545 | 549 | 2,352 | 3,764 |
| Other [(g)] | 50 | 198 | 70 | 297 | 615 |
| Trusts — | | | | | |
| Nuclear decommissioning [(h)] | 5 | 11 | 11 | 94 | 121 |
| Pension and other postretirement benefit plans [(i)] | 47 | 87 | | | 134 |
| Total | $ 6,050 | $ 9,916 | $ 7,052 | $ 22,341 | $ 45,359 |

(a) All amounts are reflected based on final maturity dates except for amounts related to FFB borrowings. As it relates to the FFB borrowings, the final maturity date is February 20, 2044; however, principal amortization is reflected beginning in 2020. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information. The Company plans to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of December 31, 2017 , as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).
(b) See Notes 1 and 11 to the financial statements.
(c) Excludes PPAs that are accounted for as leases and included in "Purchased power." See Note 7 to the financial statements under "Operating Leases" for additional information.
(d) The Company provides estimated capital expenditures for a five-year period, including capital expenditures associated with environmental regulations. These amounts exclude contractual purchase commitments for nuclear fuel and capital expenditures covered under LTSAs which are reflected in "Fuel" and "Other," respectively. At December 31, 2017 , significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations" and "Retail Regulatory Matters – Nuclear Construction" herein for additional information.
(e) Includes commitments to purchase coal, nuclear fuel, and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2017 .
(f) Estimated minimum long-term obligations for various PPA purchases from gas-fired, biomass, and wind-powered facilities.
(g) Includes LTSAs and contracts for the procurement of limestone. LTSAs include price escalation based on inflation indices.
(h) Projections of nuclear decommissioning trust fund contributions for Plant Hatch and Plant Vogtle Units 1 and 2 are based on the 2013 ARP . See Note 1 to the financial statements under "Nuclear Decommissioning" for additional information.
(i) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

**Cautionary Statement Regarding Forward-Looking Statements**

The Company's 2017 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning regulated rates, customer and sales growth, economic conditions, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, pending or potential litigation matters, access to sources of capital, projections for the qualified pension plan , postretirement benefit plans, and nuclear decommissioning trust fund contributions, financing activities, completion dates of construction projects, filings with state and federal regulatory authorities, impacts of the Tax Reform Legislation, federal income tax benefits, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including environmental laws and regulations governing air, water, land, and protection of other natural resources , and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- the uncertainty surrounding the recently enacted Tax Reform Legislation, including implementing regulations and IRS interpretations, actions that may be taken in response by regulatory authorities, and its impact, if any, on the credit ratings of the Company;
- current and future litigation or regulatory investigations, proceedings, or inquiries ;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development , construction, and operation of facilities, which include the development and construction of generating facilities with designs that have not been previously constructed, including changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor , contractor or supplier delay, non-performance under construction, operating, or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance ;
- the ability to construct facilities in accordance with the requirements of permits and licenses (including satisfaction of NRC requirements), to satisfy any environmental performance standards and the requirements of tax credits and other incentives , and to integrate facilities into the Southern Company system upon completion of construction;
- investment performance of the Company's employee and retiree benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate cases related to fuel and other cost recovery mechanisms;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- legal proceedings and regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions;
- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, and financial risks;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;

- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or physical attack and the threat of physical attacks;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on foreign currency exchange rates, counterparty performance, and the economy in general , as well as potential impacts on the benefits of the DOE loan guarantees;
- the ability of the Company to obtain additional generating capacity (or sell excess generating capacity) at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports filed by the Company from time to time with the SEC.

**The Company expressly disclaims any obligation to update any forward-looking statements.**

**STATEMENTS OF INCOME**
**For the Years Ended December 31, 2017 , 2016 , and 2015**
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| | **2017** | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| **Operating Revenues:** | | | |
| Retail revenues | **$ 7,738** | $ 7,772 | $ 7,727 |
| Wholesale revenues, non-affiliates | **163** | 175 | 215 |
| Wholesale revenues, affiliates | **26** | 42 | 20 |
| Other revenues | **383** | 394 | 364 |
| Total operating revenues | **8,310** | 8,383 | 8,326 |
| **Operating Expenses:** | | | |
| Fuel | **1,671** | 1,807 | 2,033 |
| Purchased power, non-affiliates | **416** | 361 | 289 |
| Purchased power, affiliates | **622** | 518 | 575 |
| Other operations and maintenance | **1,653** | 1,960 | 1,844 |
| Depreciation and amortization | **895** | 855 | 846 |
| Taxes other than income taxes | **409** | 405 | 391 |
| Total operating expenses | **5,666** | 5,906 | 5,978 |
| **Operating Income** | **2,644** | 2,477 | 2,348 |
| **Other Income and (Expense):** | | | |
| Interest expense, net of amounts capitalized | **(419)** | (388) | (363) |
| Other income (expense), net | **33** | 38 | 61 |
| Total other income and (expense) | **(386)** | (350) | (302) |
| **Earnings Before Income Taxes** | **2,258** | 2,127 | 2,046 |
| Income taxes | **830** | 780 | 769 |
| **Net Income** | **1,428** | 1,347 | 1,277 |
| **Dividends on Preferred and Preference Stock** | **14** | 17 | 17 |
| **Net Income After Dividends on Preferred and Preference Stock** | **$ 1,414** | $ 1,330 | $ 1,260 |

The accompanying notes are an integral part of these financial statements.

**STATEMENTS OF COMPREHENSIVE INCOME**
**For the Years Ended December 31, 2017 , 2016 , and 2015**
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| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| **Net Income** | **$ 1,428** | $ 1,347 | $ 1,277 |
| Other comprehensive income (loss): | | | |
| Qualifying hedges: | | | |
| Changes in fair value, net of tax of $-, $-, and $(6), respectively | **—** | — | (9) |
| Reclassification adjustment for amounts included in net income, net of tax of $1, $2, and $1, respectively | **3** | 2 | 2 |
| Total other comprehensive income (loss) | **3** | 2 | (7) |
| **Comprehensive Income** | **$ 1,431** | $ 1,349 | $ 1,270 |

The accompanying notes are an integral part of these financial statements.

**STATEMENTS OF CASH FLOWS**
**For the Years Ended December 31, 2017 , 2016 , and 2015**
**Georgia Power Company 2017 Annual Report**

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | (in millions) | |
| **Operating Activities:** | | | |
| Net income | **$ 1,428** | $ 1,347 | $ 1,277 |
| Adjustments to reconcile net income to net cash provided from operating activities — | | | |
| Depreciation and amortization, total | **1,100** | 1,063 | 1,029 |
| Deferred income taxes | **458** | 383 | 173 |
| Retail fuel cost over recovery — long-term | **—** | — | 106 |
| Pension, postretirement, and other employee benefits | **(68)** | (33) | 40 |
| Pension and postretirement funding | **—** | (287) | (7) |
| Settlement of asset retirement obligations | **(120)** | (123) | (29) |
| Other deferred charges — affiliated | **—** | (111) | — |
| Other, net | **(83)** | (25) | (70) |
| Changes in certain current assets and liabilities — | | | |
| -Receivables | **(256)** | 60 | 187 |
| -Fossil fuel stock | **(16)** | 104 | 37 |
| -Prepaid income taxes | **(168)** | — | 89 |
| -Other current assets | **(28)** | (38) | (62) |
| -Accounts payable | **(219)** | (42) | (259) |
| -Accrued taxes | **1** | 131 | 25 |
| -Retail fuel cost over recovery | **(84)** | (32) | 10 |
| -Other current liabilities | **(33)** | 28 | (29) |
| Net cash provided from operating activities | **1,912** | 2,425 | 2,517 |
| **Investing Activities:** | | | |
| Property additions | **(2,704)** | (2,223) | (2,091) |
| Proceeds pursuant to the Toshiba Guarantee, net of joint owner portion | **1,682** | — | — |
| Nuclear decommissioning trust fund purchases | **(574)** | (808) | (985) |
| Nuclear decommissioning trust fund sales | **568** | 803 | 980 |
| Cost of removal, net of salvage | **(100)** | (83) | (71) |
| Change in construction payables, net of joint owner portion | **223** | (35) | 217 |
| Payments pursuant to LTSAs | **(64)** | (34) | (66) |
| Sale of property | **96** | 10 | 70 |
| Other investing activities | **(39)** | 23 | 2 |
| Net cash used for investing activities | **(912)** | (2,347) | (1,944) |
| **Financing Activities:** | | | |
| Increase (decrease) in notes payable, net | **(391)** | 234 | 2 |
| Proceeds — | | | |
| Senior notes | **1,350** | 650 | 500 |
| FFB loan | **—** | 425 | 1,000 |
| Pollution control revenue bonds issuances and remarketings | **65** | — | 409 |
| Capital contributions from parent company | **431** | 594 | 62 |
| Short-term borrowings | **700** | — | 250 |
| Other long-term debt | **370** | — | — |
| Redemptions and repurchases — | | | |
| Senior notes | **(450)** | (700) | (1,175) |
| Preferred and preference stock | **(270)** | — | — |
| Pollution control revenue bonds | **(65)** | (4) | (268) |
| Short-term borrowings | **(550)** | — | (250) |
| Payment of common stock dividends | **(1,281)** | (1,305) | (1,034) |

| | | | |
|---|---|---|---|
| Other financing activities | **(60)** | (36) | (26) |
| Net cash used for financing activities | **(151)** | (142) | (530) |
| **Net Change in Cash and Cash Equivalents** | **849** | (64) | 43 |
| **Cash and Cash Equivalents at Beginning of Year** | **3** | 67 | 24 |
| **Cash and Cash Equivalents at End of Year** | **$ 852** | $ 3 | $ 67 |
| **Supplemental Cash Flow Information:** | | | |
| Cash paid during the period for — | | | |
| Interest (net of $23, $20, and $16 capitalized, respectively) | **$ 386** | $ 375 | $ 353 |
| Income taxes (net of refunds) | **496** | 170 | 506 |
| Noncash transactions — | | | |
| Accrued property additions at year-end | **550** | 336 | 387 |
| Capital lease obligation | **—** | — | 149 |

The accompanying notes are an integral part of these financial statements.

**BALANCE SHEETS**
**At December 31, 2017 and 2016**
**Georgia Power Company 2017 Annual Report**

| **Assets** | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Current Assets:** | | |
| Cash and cash equivalents | **$ 852** | $ 3 |
| Receivables — | | |
| Customer accounts receivable | **708** | 523 |
| Unbilled revenues | **255** | 224 |
| Joint owner accounts receivable | **262** | 57 |
| Affiliated | **24** | 18 |
| Other accounts and notes receivable | **76** | 81 |
| Accumulated provision for uncollectible accounts | **(3)** | (3) |
| Fossil fuel stock | **314** | 298 |
| Materials and supplies | **504** | 479 |
| Prepaid expenses | **216** | 105 |
| Other regulatory assets, current | **205** | 193 |
| Other current assets | **15** | 38 |
| Total current assets | **3,428** | 2,016 |
| **Property, Plant, and Equipment:** | | |
| In service | **34,861** | 33,841 |
| Less: Accumulated provision for depreciation | **11,704** | 11,317 |
| Plant in service, net of depreciation | **23,157** | 22,524 |
| Nuclear fuel, at amortized cost | **544** | 569 |
| Construction work in progress | **4,613** | 4,939 |
| Total property, plant, and equipment | **28,314** | 28,032 |
| **Other Property and Investments:** | | |
| Equity investments in unconsolidated subsidiaries | **53** | 60 |
| Nuclear decommissioning trusts, at fair value | **929** | 814 |
| Miscellaneous property and investments | **59** | 46 |
| Total other property and investments | **1,041** | 920 |
| **Deferred Charges and Other Assets:** | | |
| Deferred charges related to income taxes | **516** | 676 |
| Other regulatory assets, deferred | **2,932** | 2,774 |
| Other deferred charges and assets | **548** | 417 |
| Total deferred charges and other assets | **3,996** | 3,867 |
| **Total Assets** | **$ 36,779** | $ 34,835 |

The accompanying notes are an integral part of these financial statements.

**BALANCE SHEETS**
**At December 31, 2017 and 2016**
**Georgia Power Company 2017 Annual Report**

| Liabilities and Stockholder's Equity | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Current Liabilities:** | | |
| Securities due within one year | $ 857 | $ 460 |
| Notes payable | 150 | 391 |
| Accounts payable — | | |
| Affiliated | 493 | 438 |
| Other | 834 | 589 |
| Customer deposits | 270 | 265 |
| Accrued taxes — | | |
| Accrued income taxes | — | 17 |
| Other accrued taxes | 344 | 390 |
| Accrued interest | 123 | 106 |
| Accrued compensation | 219 | 224 |
| Asset retirement obligations, current | 270 | 299 |
| Other regulatory liabilities, current | 191 | 31 |
| Over recovered fuel clause revenues, current | — | 84 |
| Other current liabilities | 198 | 182 |
| Total current liabilities | 3,949 | 3,476 |
| **Long-Term Debt** (See accompanying statements) | 11,073 | 10,225 |
| **Deferred Credits and Other Liabilities:** | | |
| Accumulated deferred income taxes | 3,175 | 6,000 |
| Deferred credits related to income taxes | 3,248 | 121 |
| Accumulated deferred ITCs | 248 | 256 |
| Employee benefit obligations | 659 | 703 |
| Asset retirement obligations, deferred | 2,368 | 2,233 |
| Other deferred credits and liabilities | 128 | 199 |
| Total deferred credits and other liabilities | 9,826 | 9,512 |
| **Total Liabilities** | 24,848 | 23,213 |
| **Preferred Stock** (See accompanying statements) | — | 45 |
| **Preference Stock** (See accompanying statements) | — | 221 |
| **Common Stockholder's Equity** (See accompanying statements) | 11,931 | 11,356 |
| **Total Liabilities and Stockholder's Equity** | $ 36,779 | $ 34,835 |
| **Commitments and Contingent Matters** (See notes) | | |

The accompanying notes are an integral part of these financial statements.

**STATEMENTS OF CAPITALIZATION**
**At December 31, 2017 and 2016**
**Georgia Power Company 2017 Annual Report**

| | **2017** | 2016 | **2017** | 2016 |
|---|---|---|---|---|
| | *(in millions)* | | *(percent of total)* | |
| **Long-Term Debt:** | | | | |
| Long-term notes payable — | | | | |
| 5.70% due 2017 | **$ —** | $ 450 | | |
| 1.95% to 5.40% due 2018 | **747** | 748 | | |
| 4.25% due 2019 | **499** | 500 | | |
| 2.00% due 2020 | **950** | — | | |
| 2.40% due 2021 | **325** | 325 | | |
| 2.85% due 2022 | **400** | 400 | | |
| 3.25% to 5.95% due 2023-2043 | **4,175** | 3,775 | | |
| Variable rate (2.29% at 12/31/17) due 2018 | **100** | — | | |
| Total long-term notes payable | **7,196** | 6,198 | | |
| Other long-term debt — | | | | |
| Pollution control revenue bonds — | | | | |
| 2.35% due 2022 | **53** | 53 | | |
| 1.38% to 4.00% due 2025-2049 | **940** | 900 | | |
| Variable rate (1.84% at 12/31/17) due 2022 | **13** | 13 | | |
| Variable rates (1.59% to 1.88% at 12/31/17) due 2026-2053 | **815** | 854 | | |
| FFB loans — | | | | |
| 2.57% to 3.86% due 2020 | **44** | 44 | | |
| 2.57% to 3.86% due 2021 | **44** | 44 | | |
| 2.57% to 3.86% due 2022 | **44** | 44 | | |
| 2.57% to 3.86% due 2023-2044 | **2,493** | 2,493 | | |
| Junior subordinated note (5.00%) due 2077 | **270** | — | | |
| Total other long-term debt | **4,716** | 4,445 | | |
| Capitalized lease obligations | **154** | 169 | | |
| Unamortized debt premium (discount), net | **(12)** | (10) | | |
| Unamortized debt issuance expense | **(124)** | (117) | | |
| Total long-term debt (annual interest requirement — $437 million) | **11,930** | 10,685 | | |
| Less amount due within one year | **857** | 460 | | |
| Long-term debt excluding amount due within one year | **11,073** | 10,225 | **48.1%** | 46.8% |
| **Preferred and Preference Stock:** | | | | |
| Non-cumulative preferred stock | | | | |
| $25 par value — 6.125% | | | | |
| Authorized — 50,000,000 shares | | | | |
| Outstanding — 2017: no shares | | | | |
| — 2016: 1,800,000 shares | **—** | 45 | | |
| Non-cumulative preference stock | | | | |
| $100 par value — 6.50% | | | | |
| Authorized — 15,000,000 shares | | | | |
| Outstanding — 2017: no shares | | | | |
| — 2016: 2,250,000 shares | **—** | 221 | | |
| Total preferred and preference stock | **—** | 266 | **—** | 1.2 |
| **Common Stockholder's Equity:** | | | | |
| Common stock, without par value — | | | | |
| Authorized — 20,000,000 shares | | | | |
| Outstanding — 9,261,500 shares | **398** | 398 | | |
| Paid-in capital | **7,328** | 6,885 | | |
| Retained earnings | **4,215** | 4,086 | | |

| | | | | | |
|---|---|---|---|---|---|
| Accumulated other comprehensive loss | | **(10)** | | (13) | | |
| Total common stockholder's equity | | **11,931** | | 11,356 | **51.9** | 52.0 |
| **Total Capitalization** | **$** | **23,004** | $ | 21,847 | **100.0%** | 100.0% |

The accompanying notes are an integral part of these financial statements.

**STATEMENTS OF COMMON STOCKHOLDER'S EQUITY**
**For the Years Ended December 31, 2017 , 2016 , and 2015**
**Georgia Power Company 2017 Annual Report**

| | Number of Common Shares Issued | Common Stock | Paid-In Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|---|---|---|---|---|---|---|
| | | | | *(in millions)* | | |
| **Balance at December 31, 2014** | 9 | $ 398 | $ 6,196 | $ 3,835 | $ (8) | $ 10,421 |
| Net income after dividends on preferred and preference stock | — | — | — | 1,260 | — | 1,260 |
| Capital contributions from parent company | — | — | 79 | — | — | 79 |
| Other comprehensive income (loss) | — | — | — | — | (7) | (7) |
| Cash dividends on common stock | — | — | — | (1,034) | — | (1,034) |
| **Balance at December 31, 2015** | 9 | 398 | 6,275 | 4,061 | (15) | 10,719 |
| Net income after dividends on preferred and preference stock | — | — | — | 1,330 | — | 1,330 |
| Capital contributions from parent company | — | — | 610 | — | — | 610 |
| Other comprehensive income (loss) | — | — | — | — | 2 | 2 |
| Cash dividends on common stock | — | — | — | (1,305) | — | (1,305) |
| **Balance at December 31, 2016** | **9** | **398** | **6,885** | **4,086** | **(13)** | **11,356** |
| Net income after dividends on preferred and preference stock | **—** | **—** | **—** | **1,414** | **—** | **1,414** |
| Capital contributions from parent company | **—** | **—** | **443** | **—** | **—** | **443** |
| Other comprehensive income (loss) | **—** | **—** | **—** | **—** | **3** | **3** |
| Cash dividends on common stock | **—** | **—** | **—** | **(1,281)** | **—** | **(1,281)** |
| Other | **—** | **—** | **—** | **(4)** | **—** | **(4)** |
| **Balance at December 31, 2017** | **9** | **$ 398** | **$ 7,328** | **$ 4,215** | **$ (10)** | **$ 11,931** |

The accompanying notes are an integral part of these financial statements.

**NOTES TO FINANCIAL STATEMENTS**
**Georgia Power Company 2017 Annual Report**

**Index to the Notes to Financial Statements**

## 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

### General

Georgia Power Company (the Company) is a wholly-owned subsidiary of Southern Company, which is the parent company of the Company and three other traditional electric operating companies, as well as Southern Power, Southern Company Gas (as of July 1, 2016), SCS, Southern Linc, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, PowerSecure, Inc. (PowerSecure) (as of May 9, 2016), and other direct and indirect subsidiaries. The traditional electric operating companies – the Company, Alabama Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. The Company provides electric service to retail customers within its traditional service territory located within the State of Georgia and to wholesale customers in the Southeast. Southern Power develops, constructs, acquires, owns, and manages power generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Company Gas distributes natural gas through utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. Southern Linc provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber optics services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases and for other electric services. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants, including the Company's Plant Hatch and Plant Vogtle Units 1 and 2, and is managing construction of Plant Vogtle Units 3 and 4. PowerSecure is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure.

The equity method is used for subsidiaries in which the Company has significant influence but does not control.

The Company is subject to regulation by the FERC and the Georgia PSC. As such, the Company's financial statements reflect the effects of rate regulation in accordance with GAAP and comply with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

In 2015, the Company identified an error affecting the billing to a small number of large commercial and industrial customers under a rate plan allowing for variable demand-driven pricing from January 1, 2013 to June 30, 2015. In the second quarter 2015, the Company recorded an out of period adjustment of approximately $75 million to decrease retail revenues, resulting in a decrease to net income of approximately $47 million . The Company evaluated the effects of this error on the interim and annual periods that included the billing error. Based on an analysis of qualitative and quantitative factors, the Company determined the error was not material to any affected period and, therefore, an amendment of previously filed financial statements was not required.

### Recently Issued Accounting Standards

***Revenue***

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers* (ASC 606), replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the new standard is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

Most of the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term , as well as longer-term contractual commitments, including PPAs.

The Company has completed the evaluation of all revenue streams and determined that the adoption of ASC 606 will not change the current timing of revenue recognition for such transactions. Some revenue arrangements, such as energy-related derivatives, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed separately from revenues under ASC 606. The Company has concluded contributions in aid of construction are not in scope for ASC 606 and will continue to be accounted for as an offset to property, plant, and equipment.

The new standard is effective for reporting periods beginning after December 15, 2017. The Company applied the modified retrospective method of adoption effective January 1, 2018. The Company also utilized practical expedients which allowed it to apply the standard to open contracts at the date of adoption and to reflect the aggregate effect of all modifications when identifying performance obligations and allocating the transaction price for contracts modified before the effective date. Under the modified retrospective method of adoption, prior year reported results are not restated; however, a cumulative-effect adjustment to retained earnings at January 1, 2018 is recorded. In addition, quarterly disclosures will include comparative information on 2018 financial statement line items under current guidance. The adoption of ASC 606 did not result in a cumulative-effect adjustment .

***Leases***

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged . ASU 2016-02 is effective for fiscal years beginning after December 15, 2018 and the Company will adopt the new standard effective January 1, 2019.

The Company is currently implementing an information technology system along with the related changes to internal controls and accounting policies that will support the accounting for leases under ASU 2016-02. In addition, the Company has substantially completed a detailed inventory and analysis of its leases. In terms of rental charges and duration of contracts, the most significant leases relate to PPAs and cellular towers where the Company is the lessee and to outdoor lighting where the Company is the lessor. The Company is currently analyzing pole attachment agreements, and a lease determination has not been made at this time. While the Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

***Other***

In March 2016, the FASB issued ASU No. 2016-09, *Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Notes 5 and 8 for disclosures impacted by ASU 2016-09.

On March 10, 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017-07). ASU 2017-07 requires that an employer report the service cost component in the same line item or items as other compensation costs and requires the other components of net periodic pension and postretirement benefit costs to be separately presented in the income statement outside of income from operations. Additionally, only the service cost component is eligible for capitalization, when applicable. However, all cost components remain eligible for capitalization under FERC regulations. ASU 2017-07 will be applied retrospectively for the presentation of the service cost component and the other components of net periodic pension and postretirement benefit costs in the income statement. The capitalization of only the service cost component of net periodic pension and postretirement benefit costs in assets will be applied on a prospective basis. ASU 2017-07 is effective for periods beginning after December 15, 2017. The presentation changes required for net periodic pension and postretirement benefit costs will result in a decrease in the Company's operating income and an increase in other income for 2016 and 2017 and are expected to result in a decrease in operating income and an increase in other income for 2018. The Company adopted ASU 2017-07 effective January 1, 2018 with no material impact on its financial statements.

On August 28, 2017, the FASB issued ASU No. 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities* (ASU 2017-12), amending the hedge accounting recognition and presentation requirements. ASU 2017-12 makes more financial and non-financial hedging strategies eligible for hedge accounting, amends the related presentation and disclosure requirements, and simplifies hedge effectiveness assessment requirements. ASU 2017-12 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

**NOTES (continued)**
**Georgia Power Company 2017 Annual Report**

**Affiliate Transactions**

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations, construction management, and power pool transactions. Costs for these services amounted to $625 million , $606 million , and $585 million in 2017 , 2016 , and 2015 , respectively. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies. See Note 7 under "Operating Leases" for information on leases of cellular tower space for the Company's digital wireless communications equipment.

The Company has an agreement with Southern Nuclear under which the following nuclear-related services are rendered to the Company at cost: general executive and advisory services; general operations, management, and technical services; administrative services including procurement, accounting, employee relations, systems, and procedures services; strategic planning and budgeting services; and other services with respect to business, operations, and construction management. Costs for these services amounted to $675 million , $666 million , and $681 million in 2017 , 2016 , and 2015 , respectively. See Note 3 under "Retail Regulatory Matters – Nuclear Construction" for additional information.

The Company has entered into several PPAs with Southern Power for capacity and energy. Expenses associated with these PPAs were $235 million , $265 million , and $179 million in 2017 , 2016 , and 2015 , respectively. See Note 6 under "Capital Leases" and Note 7 under "Fuel and Purchased Power Agreements" for additional information.

The Company has a joint ownership agreement with Gulf Power under which Gulf Power owns a 25% portion of Plant Scherer Unit 3. Under this agreement, the Company operates Plant Scherer Unit 3 and Gulf Power reimburses the Company for its 25% proportionate share of the related non-fuel expenses, which were $11 million , $8 million , and $12 million in 2017 , 2016 , and 2015 , respectively. See Note 4 for additional information.

In 2014, prior to Southern Company's acquisition of PowerSecure on May 9, 2016, the Company entered into agreements with PowerSecure to build solar power generation facilities at two U.S. Army bases, as approved by the Georgia PSC. In October 2016, the two facilities began commercial operation. Payments of $119 million made by the Company to PowerSecure under the agreements since 2014 are included in utility plant in service at December 31, 2017 .

On September 1, 2016, Southern Company Gas acquired a 50% equity interest in Southern Natural Gas Company, L.L.C. (SNG). Prior to completion of the acquisition, SCS, as agent for the Company, had entered into a long-term interstate natural gas transportation agreement with SNG. The interstate transportation service provided to the Company by SNG pursuant to this agreement is governed by the terms and conditions of SNG's natural gas tariff and is subject to FERC regulation. Transportation costs under this agreement were $102 million in 2017 and $35 million for the period subsequent to Southern Company Gas' investment in SNG through December 31, 2016 .

Prior to Southern Company's acquisition of Southern Company Gas, SCS, as agent for the Company, had agreements with certain subsidiaries of Southern Company Gas to purchase natural gas. Natural gas purchases made by the Company from Southern Company Gas' subsidiaries were $22 million in 2017 and $10 million for the period subsequent to Southern Company's acquisition of Southern Company Gas through December 31, 2016 .

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2017 , 2016 , or 2015 .

The traditional electric operating companies, including the Company, and Southern Power may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

**Regulatory Assets and Liabilities**

The Company is subject to accounting requirements for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

| | 2017 | 2016 | Note |
|---|---|---|---|
| | *(in millions)* | | |
| Retiree benefit plans | **$ 1,313** | $ 1,348 | (a, k) |
| Asset retirement obligations | **945** | 893 | (b, k) |
| Deferred income tax charges | **521** | 681 | (b, c, k) |
| Storm damage reserves | **333** | 206 | (d) |
| Remaining net book value of retired assets | **146** | 166 | (e) |
| Loss on reacquired debt | **127** | 137 | (f, k) |
| Other regulatory assets | **119** | 97 | (g) |
| Vacation pay | **91** | 91 | (h, k) |
| Other cost of removal obligations | **40** | 3 | (b) |
| Cancelled construction projects | **36** | 44 | (i) |
| Deferred income tax credits | **(3,248)** | (121) | (b, c) |
| Other regulatory liabilities | **(191)** | (39) | (j, k) |
| Total regulatory assets (liabilities), net | **$ 232** | $ 3,506 | |

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Recovered and amortized over the average remaining service period which may range up to 14 years . See Note 2 for additional information.

(b) Asset retirement and other cost of removal obligations and deferred income tax assets are recovered and deferred income tax liabilities are amortized over the related property lives, which may range up to 65 years . Asset retirement and removal liabilities will be settled and trued up following completion of the related activities. Included in the deferred income tax assets is $21 million for the retiree Medicare drug subsidy, which is recovered and amortized, as approved by the Georgia PSC, through 2022.

(c) As a result of Tax Reform Legislation, these balances include $145 million of deferred income tax assets related to CWIP for Plant Vogtle Units 3 and 4 and $626 million of deferred income tax liabilities, neither of which are subject to normalization. The recovery and amortization of these amounts will be determined by the Georgia PSC. See Note 3 under "Retail Regulatory Matters – Rate Plans" and Note 5 for additional information.

(d) Previous under-recovery as of December 2013 is recorded and recovered or amortized as approved by the Georgia PSC through 2019. Amortization of $319 million related to the under-recovery from January 2014 through December 2017 is expected to be determined by the Georgia PSC in the 2019 base rate case. See Note 3 under "Retail Regulatory Matters – Storm Damage Recovery" for additional information.

(e) Amortized as approved by the Georgia PSC over periods not exceeding 10 years or through 2024. The net book value of Plant Mitchell Unit 3 at December 31, 2017 was $10 million , which will continue to be amortized through December 31, 2019 as provided in the 2013 ARP. Amortization of the remaining net book value of Plant Mitchell Unit 3 at December 31, 2019, which is expected to be approximately $4 million , and $31 million related to obsolete inventories of certain retired units is expected to be determined by the Georgia PSC in the 2019 base rate case. See Note 3 under "Retail Regulatory Matters – Integrated Resource Plan" for additional information.

(f) Recovered over either the remaining life of the original issue or, if refinanced, over the remaining life of the new issue, which currently does not exceed 35 years .

(g) Comprised of several components including deferred nuclear outages, environmental remediation, building lease, demand-side management tariff under-recovery, and fuel-hedging losses. Deferred nuclear outages are recorded and recovered or amortized over the outage cycles of each nuclear unit, which does not exceed 24 months . The building lease is recorded and recovered or amortized as approved by the Georgia PSC through 2020. The amortization of environmental remediation and demand-side management tariff under-recovery of $54 million at December 31, 2017 is expected to be determined by the Georgia PSC in the 2019 base rate case. Fuel-hedging losses are recovered through the Company's fuel cost recovery mechanism upon final settlement.

(h) Recorded as earned by employees and recovered as paid, generally within one year . This includes both vacation and banked holiday pay.

(i) Costs associated with construction of environmental controls that will not be completed as a result of unit retirements are being amortized as approved by the Georgia PSC over periods not exceeding nine years or through 2022.

(j) Comprised of certain customer refunds and fuel-hedging gains. As ordered by the Georgia PSC on January 11, 2018, approximately $188 million of the proceeds pursuant to the Toshiba Guarantee will be refunded to customers in 2018. Fuel-hedging gains are refunded through the Company's fuel cost recovery mechanism upon final settlement. See Note 3 under "Nuclear Construction" for additional information on the customer refunds related to the Toshiba Guarantee.

(k) Generally not earning a return as they are excluded from rate base or are offset in rate base by a corresponding asset or liability.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated OCI related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" for additional information.

**Revenues**

Wholesale capacity revenues from PPAs are recognized either on a levelized basis over the appropriate contract period or the amount billable under the contract terms. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between the actual recoverable costs and amounts billed in current regulated rates.

The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

**Fuel Costs**

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel.

**Income and Other Taxes**

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

Federal ITCs utilized are deferred and, upon utilization, amortized to income as a credit to reduce depreciation over the average life of the related property. The Company had $87 million in federal ITCs at December 31, 2017 that will expire by 2037. State ITCs are recognized in the period in which the credits are generated. The Company had state investment and other tax credit carryforwards totaling $495 million at December 31, 2017 , which will expire between 2019 and 2028 and are expected to be fully utilized by 2026.

The Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

**Property, Plant, and Equipment**

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the cost of equity and debt funds used during construction.

The Company's property, plant, and equipment in service consisted of the following at December 31:

| | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| Generation | **$ 17,038** | $ 16,668 |
| Transmission | **5,947** | 5,779 |
| Distribution | **9,978** | 9,553 |
| General | **1,870** | 1,813 |
| Plant acquisition adjustment | **28** | 28 |
| Total plant in service | **$ 34,861** | $ 33,841 |

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred or performed with the exception of certain generating plant maintenance costs. As mandated by the Georgia PSC, the Company defers and amortizes nuclear refueling outage costs over the unit's operating cycle. The refueling cycles are 18 and 24 months for Plant Vogtle Units 1 and 2 and Plant Hatch Units 1 and 2, respectively.

**Depreciation and Amortization**

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 2.7% in 2017 , 2.8% in 2016 , and 2.7% in 2015 . Depreciation studies are conducted periodically to update the composite rates that are approved by the Georgia PSC and the FERC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

Under the terms of the 2013 ARP, the Company amortized approximately $14 million annually from 2014 through 2016 of its remaining regulatory liability related to other cost of removal obligations.

### Asset Retirement Obligations and Other Costs of Removal

AROs are computed as the present value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities. The Company has received accounting guidance from the Georgia PSC allowing the continued accrual and recovery of other retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, amounts to be recovered are reflected in the balance sheets as a regulatory asset and any accumulated removal costs for future obligations are reflected in the balance sheets as a regulatory liability.

The ARO liability primarily relates to the Company's ash ponds, landfills, and gypsum cells that are subject to the Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA in 2015 (CCR Rule). In addition, the Company has retirement obligations related to decommissioning of the Company's nuclear facilities, which include the Company's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2, underground storage tanks, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, including the disposal of polychlorinated biphenyls in certain transformers; leasehold improvements; equipment on customer property; and property associated with the Company's rail lines and natural gas pipelines. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability in the balance sheets as ordered by the Georgia PSC. See "Nuclear Decommissioning" herein for additional information on amounts included in rates.

Details of the AROs included in the balance sheets are as follows:

| | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| Balance at beginning of year | **$ 2,532** | $ 1,916 |
| Liabilities incurred | **4** | — |
| Liabilities settled | **(120)** | (123) |
| Accretion | **89** | 77 |
| Cash flow revisions | **133** | 662 |
| Balance at end of year | **$ 2,638** | $ 2,532 |

In 2017 and 2016, the increases in cash flow revisions are primarily related to changes to the Company's closure strategy for ash ponds, landfills, and gypsum cells and the increases in liabilities settled are primarily related to ash pond closure activity.

The cost estimates for AROs related to the CCR Rule are based on information as of December 31, 2017 using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure. As further analysis is performed and closure details are developed, the Company will continue to periodically update these cost estimates as necessary.

### Nuclear Decommissioning

The NRC requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and the Georgia PSC, as well as the IRS. While the Company is allowed to prescribe an overall investment policy to the Funds' managers, the Company and its affiliates are not allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of the Company. The Funds' managers are authorized, within certain investment guidelines, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

The Company records the investment securities held in the Funds at fair value, as disclosed in Note 10, as management believes that fair value best represents the nature of the Funds. Gains and losses, whether realized or unrealized, are recorded in the regulatory liability for AROs in the balance sheets and are not included in net income or OCI. Fair value adjustments and realized gains and losses are determined on a specific identification basis.

The Funds participate in a securities lending program through the managers of the Funds. Under this program, the Funds' investment securities are loaned to institutional investors for a fee. Securities loaned are fully collateralized by cash, letters of credit, and/or securities issued or guaranteed by the U.S. government or its agencies or instrumentalities. As of December 31, 2017 and 2016 , approximately $76 million and $56 million , respectively, of the fair market value of the Funds' securities were on loan and pledged to creditors under the Funds' managers' securities lending program. The fair value of the collateral received was approximately $77 million and $58 million at December 31, 2017 and 2016 , respectively, and can only be sold by the borrower upon the return of the loaned securities. The collateral received is treated as a non-cash item in the statements of cash flows.

At December 31, 2017 , investment securities in the Funds totaled $929 million , consisting of equity securities of $415 million , debt securities of $502 million , and $12 million of other securities. At December 31, 2016 , investment securities in the Funds totaled $814 million , consisting of equity securities of $326 million , debt securities of $477 million , and $11 million of other securities. These amounts include the investment securities pledged to creditors and collateral received, and exclude receivables related to investment income and pending investment sales and payables related to pending investment purchases and the securities lending program.

Sales of the securities held in the Funds resulted in cash proceeds of $568 million , $803 million , and $980 million in 2017 , 2016 , and 2015 , respectively, all of which were reinvested. For 2017 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $108 million , which included $83 million related to unrealized gains on securities held in the Funds at December 31, 2017 . For 2016 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $38 million , which included $14 million related to unrealized losses on securities held in the Funds at December 31, 2016 . For 2015 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $3 million , which included $26 million related to unrealized gains and losses on securities held in the Funds at December 31, 2015 . While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of the securities and purpose for which the securities were acquired.

The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed plans with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

**NOTES (continued)**
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Site study cost is the estimate to decommission a specific facility as of the site study year. The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates. The estimated costs of decommissioning are based on the most current study performed in 2015 . The site study costs and external trust funds for decommissioning as of December 31, 2017 based on the Company's ownership interests were as follows:

| | Plant Hatch | Plant Vogtle Units 1 and 2 |
|---|---|---|
| Decommissioning periods: | | |
| Beginning year | 2034 | 2047 |
| Completion year | 2075 | 2079 |
| | *(in millions)* | |
| Site study costs: | | |
| Radiated structures | $ 678 | $ 568 |
| Spent fuel management | 160 | 147 |
| Non-radiated structures | 64 | 89 |
| Total site study costs | $ 902 | $ 804 |
| External trust funds | $ 583 | $ 346 |

For ratemaking purposes, the Company's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities and the site study estimate for spent fuel management as of 2012. Under the 2013 ARP, the Georgia PSC approved annual decommissioning cost for ratemaking of $4 million and $2 million for Plant Hatch and Plant Vogtle Units 1 and 2, respectively. Significant assumptions used to determine the costs for ratemaking include an estimated inflation rate of 2.4% and an estimated trust earnings rate of 4.4% . The Company expects the Georgia PSC to review and adjust, if necessary, the amounts collected in rates for nuclear decommissioning costs in the Company's 2019 base rate case.

**Allowance for Funds Used During Construction**

The Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently, AFUDC increases the revenue requirement and is recovered over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. For the years 2017 , 2016 , and 2015 , the average AFUDC rates were 5.6% , 6.9% , and 6.5% , respectively, and AFUDC capitalized was $63 million , $68 million , and $56 million , respectively. AFUDC, net of income taxes, as a percentage of net income after dividends on preferred and preference stock was 3.8% , 4.6% , and 3.9% for 2017 , 2016 , and 2015 , respectively. See Note 3 under "Retail Regulatory Matters – Nuclear Construction" for additional information on the inclusion of construction costs related to Plant Vogtle Units 3 and 4 in rate base effective January 1, 2011.

**Impairment of Long-Lived Assets and Intangibles**

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

**Storm Damage Recovery**

The Company defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. Beginning January 1, 2014, the Company is accruing $30 million annually under the 2013 ARP that is recoverable through base rates. As of December 31, 2017 and December 31, 2016 , the balance in the regulatory asset related to storm damage was $333 million and $206 million , respectively, with approximately $30 million included in other regulatory assets, current for both years and approximately $303 million and $176 million included in other regulatory assets, deferred, respectively. The annual recovery amount is expected to be reviewed by the Georgia PSC and adjusted in future regulatory proceedings. As a result of this regulatory treatment, costs related to storms are generally not expected to have a material impact on the Company's earnings. See Note 3 under "Retail Regulatory Matters – Storm Damage Recovery" for additional information.

### Environmental Remediation Recovery

The Company maintains a reserve for environmental remediation as mandated by the Georgia PSC. In 2013, the Georgia PSC approved the 2013 ARP including the recovery of approximately $2 million annually through the environmental compliance cost recovery (ECCR) tariff. The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable and reasonably estimable and reduces the reserve as expenditures are incurred. Any difference between the liabilities accrued and cost recovered through rates is deferred as a regulatory asset or liability. The annual recovery amount is expected to be reviewed by the Georgia PSC and adjusted in future regulatory proceedings. As a result of this regulatory treatment, environmental remediation liabilities generally are not expected to have a material impact on the Company's earnings. As of December 31, 2017 , the balance of the environmental remediation liability was $22 million and is included in other current liabilities. As of December 31, 2017 , the balance of under recovered environmental remediation costs was $49 million , with approximately $2 million included in other regulatory assets, current and approximately $47 million included as other regulatory assets, deferred. As of December 31, 2016 , the balance of the environmental remediation liability was $17 million and is included in other current liabilities. As of December 31, 2016 , the balance of under recovered environmental remediation costs was $35 million , with approximately $2 million included in other regulatory assets, current and approximately $33 million included as other regulatory assets, deferred. See Note 3 under "Environmental Matters – Environmental Remediation" for additional information.

### Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

### Materials and Supplies

Generally, materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

### Fuel Inventory

Fuel inventory includes the average cost of coal, natural gas, and oil, as well as transportation and emissions allowances. Fuel is recorded to inventory when purchased and then expensed, at weighted average cost, as used and recovered by the Company through fuel cost recovery rates approved by the Georgia PSC. Emissions allowances granted by the EPA are included in inventory at zero cost.

### Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities on the balance sheets (included in "Other") and are measured at fair value. See Note 10 for additional information regarding fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the Georgia PSC-approved fuel-hedging program result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded on a net basis in the statements of income. Cash flows from derivatives are classified on the statements of cash flows in the same category as the hedged item. See Note 11 for additional information regarding derivatives.

The Company offsets fair value amounts recognized for multiple derivative instruments executed with the same counterparty under netting arrangements. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2017 .

The Company is exposed to potential losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

### Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts included in net income.

## 2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2017 and no mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2018 . The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the Georgia PSC and the FERC. For the year ending December 31, 2018 , no other postretirement trust contributions are expected.

### Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the net periodic costs for the pension and other postretirement benefit plans for the following year and the benefit obligations as of the measurement date are presented below.

| Assumptions used to determine net periodic costs: | 2017 | 2016 | 2015 |
|---|---|---|---|
| **Pension plans** | | | |
| Discount rate – benefit obligations | **4.40%** | 4.65% | 4.18% |
| Discount rate – interest costs | **3.72** | 3.86 | 4.18 |
| Discount rate – service costs | **4.83** | 5.03 | 4.49 |
| Expected long-term return on plan assets | **7.95** | 8.20 | 8.20 |
| Annual salary increase | **4.46** | 4.46 | 3.59 |
| **Other postretirement benefit plans** | | | |
| Discount rate – benefit obligations | **4.23%** | 4.49% | 4.03% |
| Discount rate – interest costs | **3.55** | 3.67 | 4.03 |
| Discount rate – service costs | **4.63** | 4.88 | 4.39 |
| Expected long-term return on plan assets | **6.79** | 6.27 | 6.48 |
| Annual salary increase | **4.46** | 4.46 | 3.59 |

| Assumptions used to determine benefit obligations: | 2017 | 2016 |
|---|---|---|
| **Pension plans** | | |
| Discount rate | **3.79%** | 4.40% |
| Annual salary increase | **4.46** | 4.46 |
| **Other postretirement benefit plans** | | |
| Discount rate | **3.68%** | 4.23% |
| Annual salary increase | **4.46** | 4.46 |

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of eight different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2017 were as follows:

| | Initial Cost Trend Rate | Ultimate Cost Trend Rate | Year That Ultimate Rate is Reached |
|---|---|---|---|
| Pre-65 | 6.50% | 4.50% | 2026 |
| Post-65 medical | 5.00 | 4.50 | 2026 |
| Post-65 prescription | 10.00 | 4.50 | 2026 |

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2017 as follows:

| | 1 Percent Increase | 1 Percent Decrease |
|---|---|---|
| | *(in millions)* | |
| Benefit obligation | $ 59 | $ 50 |
| Service and interest costs | 2 | 2 |

**Pension Plans**

The total accumulated benefit obligation for the pension plans was $3.8 billion at December 31, 2017 and $3.5 billion at December 31, 2016 . Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2017 and 2016 were as follows:

| | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Change in benefit obligation** | | |
| Benefit obligation at beginning of year | **$ 3,800** | $ 3,615 |
| Service cost | **74** | 70 |
| Interest cost | **138** | 136 |
| Benefits paid | **(187)** | (164) |
| Actuarial (gain) loss | **363** | 143 |
| Balance at end of year | **4,188** | 3,800 |
| **Change in plan assets** | | |
| Fair value of plan assets at beginning of year | **3,621** | 3,196 |
| Actual return (loss) on plan assets | **610** | 288 |
| Employer contributions | **14** | 301 |
| Benefits paid | **(187)** | (164) |
| Fair value of plan assets at end of year | **4,058** | 3,621 |
| Accrued liability | **$ (130)** | $ (179) |

At December 31, 2017 , the projected benefit obligations for the qualified and non-qualified pension plans were $4.0 billion and $153 million , respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2017 and 2016 related to the Company's pension plans consist of the following:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| Prepaid pension costs | **$ 23** | $ — |
| Other regulatory assets, deferred | **1,105** | 1,129 |
| Other current liabilities | **(15)** | (14) |
| Employee benefit obligations | **(138)** | (165) |

Presented below are the amounts included in regulatory assets at December 31, 2017 and 2016 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2018 .

| | 2017 | 2016 | Estimated Amortization in 2018 |
|---|---|---|---|
| | | *(in millions)* | |
| Prior service cost | **$ 14** | $ 17 | **$ 2** |
| Net (gain) loss | **1,091** | 1,112 | **69** |
| Regulatory assets | **$ 1,105** | $ 1,129 | |

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2017 and 2016 are presented in the following table:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Regulatory assets:** | | |
| Beginning balance | **$ 1,129** | $ 1,076 |
| Net (gain) loss | **36** | 99 |
| Change in prior service costs | **—** | 14 |
| Reclassification adjustments: | | |
| Amortization of prior service costs | **(3)** | (5) |
| Amortization of net gain (loss) | **(57)** | (55) |
| Total reclassification adjustments | **(60)** | (60) |
| Total change | **(24)** | 53 |
| Ending balance | **$ 1,105** | $ 1,129 |

Components of net periodic pension cost were as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| Service cost | **$ 74** | $ 70 | $ 73 |
| Interest cost | **138** | 136 | 154 |
| Expected return on plan assets | **(283)** | (258) | (251) |
| Recognized net (gain) loss | **57** | 55 | 76 |
| Net amortization | **3** | 5 | 9 |
| Net periodic pension cost | **$ (11)** | $ 8 | $ 61 |

Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2017 , estimated benefit payments were as follows:

| | **Benefit Payments** |
|---|---|
| | *(in millions)* |
| 2018 | $ 196 |
| 2019 | 201 |
| 2020 | 207 |
| 2021 | 210 |
| 2022 | 216 |
| 2023 to 2027 | 1,156 |

**Other Postretirement Benefits**

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2017 and 2016 were as follows:

| | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Change in benefit obligation** | | |
| Benefit obligation at beginning of year | **$ 847** | $ 854 |
| Service cost | **7** | 6 |
| Interest cost | **29** | 30 |
| Benefits paid | **(51)** | (45) |
| Actuarial (gain) loss | **28** | (1) |
| Retiree drug subsidy | **3** | 3 |
| Balance at end of year | **863** | 847 |
| **Change in plan assets** | | |
| Fair value of plan assets at beginning of year | **354** | 358 |
| Actual return (loss) on plan assets | **54** | 21 |
| Employer contributions | **26** | 17 |
| Benefits paid | **(48)** | (42) |
| Fair value of plan assets at end of year | **386** | 354 |
| Accrued liability | **$ (477)** | $ (493) |

Amounts recognized in the balance sheets at December 31, 2017 and 2016 related to the Company's other postretirement benefit plans consist of the following:

| | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| Other regulatory assets, deferred | **$ 202** | $ 213 |
| Employee benefit obligations | **(477)** | (493) |

Presented below are the amounts included in regulatory assets at December 31, 2017 and 2016 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2018 .

| | 2017 | 2016 | Estimated Amortization in 2018 |
|---|---|---|---|
| | | (in millions) | |
| Prior service cost | $ 5 | $ 6 | $ 1 |
| Net (gain) loss | 197 | 207 | 9 |
| Regulatory assets | $ 202 | $ 213 | |

The changes in the balance of regulatory assets related to the other postretirement benefit plans for the plan years ended December 31, 2017 and 2016 are presented in the following table:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| **Regulatory assets:** | | |
| Beginning balance | $ 213 | $ 223 |
| Net (gain) loss | (2) | — |
| Reclassification adjustments: | | |
| Amortization of prior service costs | (1) | (1) |
| Amortization of net gain (loss) | (8) | (9) |
| Total reclassification adjustments | (9) | (10) |
| Total change | (11) | (10) |
| Ending balance | $ 202 | $ 213 |

Components of the other postretirement benefit plans' net periodic cost were as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | (in millions) | |
| Service cost | $ 7 | $ 6 | $ 7 |
| Interest cost | 29 | 30 | 34 |
| Expected return on plan assets | (25) | (22) | (24) |
| Net amortization | 9 | 10 | 11 |
| Net periodic postretirement benefit cost | $ 20 | $ 24 | $ 28 |

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

| | Benefit Payments | Subsidy Receipts | Total |
|---|---|---|---|
| | | (in millions) | |
| 2018 | $ 55 | $ (3) | $ 52 |
| 2019 | 55 | (3) | 52 |
| 2020 | 56 | (3) | 53 |
| 2021 | 57 | (4) | 53 |
| 2022 | 58 | (4) | 54 |
| 2023 to 2027 | 288 | (21) | 267 |

**Benefit Plan Assets**

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended. The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2017 and 2016 , along with the targeted mix of assets for each plan, is presented below:

| | Target | **2017** | 2016 |
|---|---|---|---|
| **Pension plan assets:** | | | |
| Domestic equity | 26% | **31%** | 29% |
| International equity | 25 | **25** | 22 |
| Fixed income | 23 | **24** | 29 |
| Special situations | 3 | **1** | 2 |
| Real estate investments | 14 | **13** | 13 |
| Private equity | 9 | **6** | 5 |
| Total | 100% | **100%** | 100% |
| **Other postretirement benefit plan assets:** | | | |
| Domestic equity | 36% | **38%** | 35% |
| International equity | 24 | **24** | 24 |
| Domestic fixed income | 33 | **31** | 35 |
| Special situations | 1 | **1** | 1 |
| Real estate investments | 4 | **4** | 4 |
| Private equity | 2 | **2** | 1 |
| Total | 100% | **100%** | 100% |

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns and interest rates, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices. Management believes the portfolio is well-diversified with no significant concentrations of risk.

***Investment Strategies***

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Trust-owned life insurance (TOLI).*** Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.

- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

***Benefit Plan Asset Fair Values***

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2017 and 2016 . The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- ***Domestic and international equity.*** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- ***Fixed income.*** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- ***TOLI.*** Investments in TOLI policies are classified as Level 2 investments and are valued based on the underlying investments held in the policy's separate account. The underlying assets are equity and fixed income pooled funds that are comprised of Level 1 and Level 2 securities.
- ***Real estate investments, private equity, and special situations investments.*** Investments in real estate, private equity, and special situations are generally classified as Net Asset Value as a Practical Expedient, since the underlying assets typically do not have publicly available observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. Techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, discounted cash flow analysis, prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals. The fair value of partnerships is determined by aggregating the value of the underlying assets less liabilities.

**NOTES (continued)**
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The fair values of pension plan assets as of December 31, 2017 and 2016 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| **As of December 31, 2017:** | **Quoted Prices in Active Markets for Identical Assets (Level 1)** | **Significant Other Observable Inputs (Level 2)** | **Significant Unobservable Inputs (Level 3)** | **Net Asset Value as a Practical Expedient (NAV)** | **Total** |
| | | | *(in millions)* | | |
| Assets: | | | | | |
| Domestic equity (*) | $ 819 | $ 394 | $ — | $ — | $ 1,213 |
| International equity (*) | 529 | 477 | — | — | 1,006 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 286 | — | — | 286 |
| Mortgage- and asset-backed securities | — | 3 | — | — | 3 |
| Corporate bonds | — | 409 | — | — | 409 |
| Pooled funds | — | 221 | — | — | 221 |
| Cash equivalents and other | 74 | 4 | — | — | 78 |
| Real estate investments | 160 | — | — | 404 | 564 |
| Special situations | — | — | — | 61 | 61 |
| Private equity | — | — | — | 228 | 228 |
| Total | $ 1,582 | $ 1,794 | $ — | $ 693 | $ 4,069 |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

| As of December 31, 2016: | Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Net Asset Value as a Practical Expedient (NAV) | Total |
|---|---|---|---|---|---|
| | | | *(in millions)* | | |
| Assets: | | | | | |
| Domestic equity (*) | $ 686 | $ 317 | $ — | $ — | $ 1,003 |
| International equity (*) | 420 | 380 | — | — | 800 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 201 | — | — | 201 |
| Mortgage- and asset-backed securities | — | 4 | — | — | 4 |
| Corporate bonds | — | 338 | — | — | 338 |
| Pooled funds | — | 179 | — | — | 179 |
| Cash equivalents and other | 340 | 1 | — | — | 341 |
| Real estate investments | 106 | — | — | 394 | 500 |
| Special situations | — | — | — | 61 | 61 |
| Private equity | — | — | — | 188 | 188 |
| Total | $ 1,552 | $ 1,420 | $ — | $ 643 | $ 3,615 |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

The fair values of other postretirement benefit plan assets as of December 31, 2017 and 2016 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

| As of December 31, 2017: | Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Net Asset Value as a Practical Expedient (NAV) | Total |
|---|---|---|---|---|---|
| | | | *(in millions)* | | |
| Assets: | | | | | |
| Domestic equity (*) | $ 53 | $ 11 | $ — | $ — | $ 64 |
| International equity (*) | 14 | 46 | — | — | 60 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 6 | — | — | 6 |
| Corporate bonds | — | 11 | — | — | 11 |
| Pooled funds | — | 41 | — | — | 41 |
| Cash equivalents and other | 4 | — | — | — | 4 |
| Trust-owned life insurance | — | 173 | — | — | 173 |
| Real estate investments | 6 | — | — | 11 | 17 |
| Special situations | — | — | — | 2 | 2 |
| Private equity | — | — | — | 6 | 6 |
| Total | $ 77 | $ 288 | $ — | $ 19 | $ 384 |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

| As of December 31, 2016: | Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Net Asset Value as a Practical Expedient (NAV) | Total |
|---|---|---|---|---|---|
| | | | (in millions) | | |
| Assets: | | | | | |
| Domestic equity (*) | $ 45 | $ 9 | $ — | $ — | $ 54 |
| International equity (*) | 11 | 37 | — | — | 48 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 5 | — | — | 5 |
| Corporate bonds | — | 9 | — | — | 9 |
| Pooled funds | — | 38 | — | — | 38 |
| Cash equivalents and other | 15 | — | — | — | 15 |
| Trust-owned life insurance | — | 162 | — | — | 162 |
| Real estate investments | 3 | — | — | 11 | 14 |
| Special situations | — | — | — | 2 | 2 |
| Private equity | — | — | — | 5 | 5 |
| Total | $ 74 | $ 260 | $ — | $ 18 | $ 352 |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

**Employee Savings Plan**

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company matches a portion of the first 6% of employee base salary contributions. The maximum Company match is 5.1% of an employee's base salary. Total matching contributions made to the plan for 2017 , 2016 , and 2015 were $26 million , $27 million , and $26 million , respectively.

## 3. CONTINGENCIES AND REGULATORY MATTERS

**General Litigation Matters**

In 2011, plaintiffs filed a putative class action against the Company in the Superior Court of Fulton County, Georgia alleging that the Company's collection in rates of municipal franchise fees (all of which are remitted to municipalities) exceeded the amounts allowed in orders of the Georgia PSC and alleging certain state tort law claims. In November 2016, the Georgia Court of Appeals reversed the trial court's previous dismissal of the case and remanded the case to the trial court for further proceedings. The Company filed a petition for writ of certiorari with the Georgia Supreme Court, which was granted on August 28, 2017. A decision from the Georgia Supreme Court is expected in late 2018. The Company believes the plaintiffs' claims have no merit and intends to vigorously defend itself in this matter. The ultimate outcome of this matter cannot be determined at this time.

The Company is also subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as standards for air, water, land, and protection of other natural resources, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by $CO_2$ and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

**Environmental Matters**

***Environmental Remediation***

The Company must comply with environmental laws and regulations governing the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up affected sites. See Note 1 under "Environmental Remediation Recovery" for additional information.

The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable and reasonably estimable. The Company's environmental remediation liability as of December 31, 2017 and 2016 was $22 million and $17 million , respectively. The Company has been designated or identified as a potentially responsible party at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act, and assessment and potential cleanup of such sites is expected.

The ultimate outcome of these matters cannot be determined at this time; however, as a result of the Company's regulatory treatment for environmental remediation expenses described in Note 1 under "Environmental Remediation Recovery," these matters are not expected to have a material impact on the Company's financial statements.

**Nuclear Fuel Disposal Costs**

Acting through the DOE and pursuant to the Nuclear Waste Policy Act of 1982, the U.S. government entered into contracts with the Company that require the DOE to dispose of spent nuclear fuel and high level radioactive waste generated at Plant Hatch and Plant Vogtle Units 1 and 2 beginning no later than January 31, 1998. The DOE has yet to commence the performance of its contractual and statutory obligation to dispose of spent nuclear fuel. Consequently, the Company pursued and continues to pursue legal remedies against the U.S. government for its partial breach of contract.

In 2014, the Court of Federal Claims entered a judgment in favor of the Company in its spent nuclear fuel lawsuit seeking damages for the period from January 1, 2005 through December 31, 2010. In 2015, the Company recovered approximately $18 million , based on its ownership interests, which was credited to accounts where the original costs were charged, and used to reduce rate base, fuel, and cost of service for the benefit of customers.

In 2014, the Company filed lawsuits against the U.S. government for the costs of continuing to store spent nuclear fuel at Plant Hatch and Plant Vogtle Units 1 and 2 for the period from January 1, 2011 through December 31, 2013. The damage period was subsequently extended to December 31, 2014. On October 10, 2017, the Company filed additional lawsuits against the U.S. government in the Court of Federal Claims for the costs of continuing to store spent nuclear fuel at Plant Hatch and Plant Vogtle Units 1 and 2 for the period from January 1, 2015 through December 31, 2017. Damages will continue to accumulate until the issue is resolved or storage is provided. No amounts have been recognized in the financial statements as of December 31, 2017 for any potential recoveries from the pending lawsuits. The final outcome of these matters cannot be determined at this time. However, the Company expects to credit any recovery back for the benefit of customers in accordance with direction from the Georgia PSC and, therefore, no material impact on the Company's net income is expected.

On-site dry spent fuel storage facilities are operational at Plant Vogtle Units 1 and 2 and Plant Hatch. Facilities can be expanded to accommodate spent fuel through the expected life of each plant.

**FERC Matters**

The Company has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies (including the Company) and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In 2015, the FERC issued an order finding that the traditional electric operating companies' (including the Company's) and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional electric operating companies (including the Company) and Southern Power filed a request for rehearing and filed their response with the FERC in 2015.

In December 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. On May 17, 2017, the FERC accepted the traditional electric operating companies' (including the Company's) and Southern Power's compliance filing accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

On October 25, 2017, the FERC issued an order in response to the traditional electric operating companies' (including the Company's) and Southern Power's June 29, 2017 triennial updated market power analysis. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show cause within 60 days why market-based rate authority should not be revoked in certain areas adjacent to the area presently under mitigation in accordance with the February 2, 2017 order or to provide a mitigation plan to further address market power concerns. On November 10, 2017, the traditional electric operating companies (including the Company) and Southern Power responded to the FERC and proposed to resolve matters by applying the alternative mitigation authorized by the February 2, 2017 order to the adjacent areas made the subject of the October 25, 2017 order.

The ultimate outcome of these matters cannot be determined at this time.

**Retail Regulatory Matters**

***Rate Plans***

Pursuant to the terms and conditions of a settlement agreement related to Southern Company's acquisition of Southern Company Gas approved by the Georgia PSC in April 2016, the 2013 ARP will continue in effect until December 31, 2019, and the Company will be required to file its next base rate case by July 1, 2019. Furthermore, through December 31, 2019, the Company and Atlanta Gas Light Company each will retain their respective merger savings, net of transition costs, as defined in the settlement agreement; through December 31, 2022, such net merger savings applicable to each will be shared on a 60 / 40 basis with their respective customers; thereafter, all merger savings will be retained by customers.

In accordance with the 2013 ARP, the Georgia PSC approved increases to tariffs effective January 1, 2016 as follows: (1) traditional base tariff rates by approximately $49 million ; (2) ECCR tariff by approximately $75 million ; (3) Demand-Side Management tariffs by approximately $3 million ; and (4) Municipal Franchise Fee tariff by approximately $13 million , for a total increase in base revenues of approximately $140 million . There were no changes to these tariffs in 2017.

Under the 2013 ARP, the Company's retail ROE is set at 10.95% and earnings are evaluated against a retail ROE range of 10.00% to 12.00% . Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by the Company. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. In 2015, the Company's retail ROE was within the allowed retail ROE range. In 2016, the Company's retail ROE exceeded 12.00% , and the Company will refund to retail customers approximately $44 million in 2018, as approved by the Georgia PSC on January 16, 2018. In 2017, the Company's retail ROE was within the allowed retail ROE range, subject to review and approval by the Georgia PSC.

On January 19, 2018, the Georgia PSC issued an order on the Tax Reform Legislation, which was amended on February 16, 2018 (Tax Order). In accordance with the Tax Order, the Company is required to submit its analysis of the Tax Reform Legislation and related recommendations to address the related impacts on the Company 's cost of service and annual revenue requirements by March 6, 2018. The ultimate outcome of this matter cannot be determined at this time.

***Integrated Resource Plan***

In July 2016, the Georgia PSC approved the Company's triennial Integrated Resource Plan (2016 IRP) including the decertification and retirement of Plant Mitchell Units 3, 4A, and 4B ( 217 MWs) and Plant Kraft Unit 1 ( 17 MWs) , as well as the decertification of the Intercession City unit ( 143 MWs total capacity) . In August 2016, the Plant Mitchell and Plant Kraft units were retired and the Company sold its 33% ownership interest in the Intercession City unit to Duke Energy Florida, LLC.

Additionally, the Georgia PSC approved the Company's environmental compliance strategy and related expenditures proposed in the 2016 IRP, including measures taken to comply with existing government-imposed environmental mandates, subject to limits on expenditures for Plant McIntosh Unit 1 and Plant Hammond Units 1 through 4.

The Georgia PSC approved the reclassification of the remaining net book value of Plant Mitchell Unit 3 and costs associated with materials and supplies remaining at the unit retirement date to a regulatory asset. Recovery of the unit's net book value will continue through December 31, 2019, as provided in the 2013 ARP. The timing of the recovery of the remaining balance of the unit's net book value as of December 31, 2019 and costs associated with materials and supplies remaining at the unit retirement date was deferred for consideration in the Company's 2019 base rate case.

The Georgia PSC also approved the Renewable Energy Development Initiative (REDI) to procure an additional 1,200 MWs of renewable resources primarily utilizing market-based prices established through a competitive bidding process with expected in-service dates between 2018 and 2021. Additionally, 200 MWs of self-build capacity for use by the Company was approved, as well as consideration for no more than 200 MWs of capacity as part of a renewable commercial and industrial program.

In 2017, the Company filed for and received certification for 510 MWs of REDI utility-scale PPAs for solar generation resources, which are expected to be in operation by the end of 2019. The Company also filed for and received approval to develop several solar generation projects to fulfill the approved self-build capacity.

In the 2016 IRP, the Georgia PSC also approved recovery of costs up to $99 million through June 30, 2019 to preserve nuclear generation as an option at a future generation site in Stewart County, Georgia. On March 7, 2017, the Georgia PSC approved the Company's decision to suspend work at the site due to changing economics, including lower load forecasts and fuel costs. The timing of recovery for costs incurred of approximately $50 million is expected to be determined by the Georgia PSC in a future rate case.

***Fuel Cost Recovery***

The Company has established fuel cost recovery rates approved by the Georgia PSC. In 2015, the Georgia PSC approved the Company's request to lower annual billings by approximately $350 million effective January 1, 2016. In May 2016, the Georgia PSC approved the Company's request to further lower annual billings under an interim fuel rider by approximately $313 million effective June 1, 2016, which expired on December 31, 2017. The Georgia PSC will review the Company's cumulative over or under recovered fuel balance no later than September 1, 2018 and evaluate the need to file a fuel case unless the Company deems it necessary to file a fuel case at an earlier time. The Company continues to be allowed to adjust its fuel cost recovery rates under an interim fuel rider prior to the next fuel case if the under recovered fuel balance exceeds $200 million .

The Company's fuel cost recovery mechanism includes costs associated with a natural gas hedging program, as revised and approved by the Georgia PSC, allowing the use of an array of derivative instruments within a 48 -month time horizon.

The Company's under recovered fuel balance totaled $165 million at December 31, 2017 and is included in current assets. At December 31, 2016 , the Company's over recovered fuel balance totaled $84 million and is included in over recovered fuel clause revenues, current.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on the Company's revenues or net income, but will affect cash flow.

***Storm Damage Recovery***

The Company is accruing $30 million annually through December 31, 2019, as provided in the 2013 ARP, for incremental operating and maintenance costs of damage from major storms to its transmission and distribution facilities. Hurricanes Irma and Matthew caused significant damage to the Company's transmission and distribution facilities during September 2017 and October 2016, respectively. The incremental restoration costs related to these hurricanes deferred in the regulatory asset for storm damage totaled approximately $260 million . At December 31, 2017 , the total balance in the regulatory asset related to storm damage was $333 million . The rate of storm damage cost recovery is expected to be adjusted as part of the Company's next base rate case required to be filed by July 1, 2019. As a result of this regulatory treatment, costs related to storms are not expected to have a material impact on the Company's financial statements. See Note 1 under "Storm Damage Recovery" for additional information regarding the Company's storm damage reserve.

***Nuclear Construction***

*Project Status*

In 2009, the Georgia PSC certified construction of Plant Vogtle Units 3 and 4. In 2012, the NRC issued the related combined construction and operating licenses, which allowed full construction of the two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities to begin. Until March 2017, construction on Plant Vogtle Units 3 and 4 continued under the Vogtle 3 and 4 Agreement, which was a substantially fixed price agreement. On March 29, 2017, the EPC Contractor filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code.

In connection with the EPC Contractor's bankruptcy filing, the Company, acting for itself and as agent for the Vogtle Owners, entered into the Interim Assessment Agreement with the EPC Contractor to allow construction to continue. The Interim Assessment Agreement expired on July 27, 2017 when the Vogtle Services Agreement became effective. In August 2017, following completion of comprehensive cost to complete and cancellation cost assessments, the Company filed its seventeenth

VCM report with the Georgia PSC, which included a recommendation to continue construction of Plant Vogtle Units 3 and 4, with Southern Nuclear serving as project manager and Bechtel serving as the primary construction contractor. On December 21, 2017, the Georgia PSC approved the Company's recommendation to continue construction.

The Company expects Plant Vogtle Units 3 and 4 to be placed in service by November 2021 and November 2022, respectively. The Company's revised capital cost forecast for its 45.7% proportionate share of Plant Vogtle Units 3 and 4 is $8.8 billion ( $7.3 billion after reflecting the impact of payments received under the Guarantee Settlement Agreement and the Customer Refunds, each as defined herein). The Company's CWIP balance for Plant Vogtle Units 3 and 4 was $3.3 billion at December 31, 2017 , which is net of the Guarantee Settlement Agreement payments less the Customer Refunds. The Company estimates that its financing costs for construction of Plant Vogtle Units 3 and 4 will total approximately $3.1 billion , of which $1.6 billion had been incurred through December 31, 2017 .

*Vogtle 3 and 4 Agreement and EPC Contractor Bankruptcy*

In 2008, the Company, acting for itself and as agent for the Vogtle Owners, entered into the Vogtle 3 and 4 Agreement. Under the terms of the Vogtle 3 and 4 Agreement, the Vogtle Owners agreed to pay a purchase price subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. Under the Toshiba Guarantee, Toshiba guaranteed certain payment obligations of the EPC Contractor, including any liability of the EPC Contractor for abandonment of work. In the first quarter 2016, Westinghouse delivered to the Vogtle Owners a total of $920 million of letters of credit from financial institutions (Westinghouse Letters of Credit) to secure a portion of the EPC Contractor's potential obligations under the Vogtle 3 and 4 Agreement.

Subsequent to the EPC Contractor bankruptcy filing, a number of subcontractors to the EPC Contractor alleged non-payment by the EPC Contractor for amounts owed for work performed on Plant Vogtle Units 3 and 4. The Company, acting for itself and as agent for the Vogtle Owners, has taken actions to remove liens filed by these subcontractors through the posting of surety bonds. Related to such liens, certain subcontractors have filed, and additional subcontractors may file, actions against the EPC Contractor and the Vogtle Owners to preserve their payment rights with respect to such claims. All amounts associated with the removal of subcontractor liens and other EPC Contractor pre-petition accounts payable have been paid or accrued as of December 31, 2017.

On June 9, 2017, the Company and the other Vogtle Owners and Toshiba entered into a settlement agreement regarding the Toshiba Guarantee (Guarantee Settlement Agreement). Pursuant to the Guarantee Settlement Agreement, Toshiba acknowledged the amount of its obligation was $3.68 billion (Guarantee Obligations), of which the Company's proportionate share was approximately $1.7 billion . The Guarantee Settlement Agreement provided for a schedule of payments for the Guarantee Obligations beginning in October 2017 and continuing through January 2021. Toshiba made the first three payments as scheduled. On December 8, 2017, the Company, the other Vogtle Owners, certain affiliates of the Municipal Electric Authority of Georgia (MEAG Power), and Toshiba entered into Amendment No. 1 to the Guarantee Settlement Agreement (Guarantee Settlement Agreement Amendment). The Guarantee Settlement Agreement Amendment provided that Toshiba's remaining payment obligations under the Guarantee Settlement Agreement were due and payable in full on December 15, 2017, which Toshiba satisfied on December 14, 2017. Pursuant to the Guarantee Settlement Agreement Amendment, Toshiba was deemed to be the owner of certain pre-petition bankruptcy claims of the Company, the other Vogtle Owners, and certain affiliates of MEAG Power against Westinghouse, and the Company and the other Vogtle Owners surrendered the Westinghouse Letters of Credit.

Additionally, on June 9, 2017, the Company, acting for itself and as agent for the other Vogtle Owners, and the EPC Contractor entered into the Vogtle Services Agreement, which was amended and restated on July 20, 2017. On July 20, 2017, the bankruptcy court approved the EPC Contractor's motion seeking authorization to (i) enter into the Vogtle Services Agreement, (ii) assume and assign to the Vogtle Owners certain project-related contracts, (iii) join the Vogtle Owners as counterparties to certain assumed project-related contracts, and (iv) reject the Vogtle 3 and 4 Agreement. The Vogtle Services Agreement, and the EPC Contractor's rejection of the Vogtle 3 and 4 Agreement, became effective upon approval by the DOE on July 27, 2017. The Vogtle Services Agreement will continue until the start-up and testing of Plant Vogtle Units 3 and 4 are complete and electricity is generated and sold from both units. The Vogtle Services Agreement is terminable by the Vogtle Owners upon 30 days' written notice.

Effective October 23, 2017, the Company, acting for itself and as agent for the other Vogtle Owners, entered into a construction completion agreement with Bechtel, whereby Bechtel will serve as the primary contractor for the remaining construction activities for Plant Vogtle Units 3 and 4 (Bechtel Agreement). Facility design and engineering remains the responsibility of the EPC Contractor under the Vogtle Services Agreement. The Bechtel Agreement is a cost reimbursable plus fee arrangement, whereby Bechtel will be reimbursed for actual costs plus a base fee and an at-risk fee, which is subject to adjustment based on Bechtel's performance against cost and schedule targets. Each Vogtle Owner is severally (not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to Bechtel under the Bechtel Agreement. The Vogtle Owners may terminate the Bechtel Agreement at any time for their convenience, provided that the Vogtle Owners will be required to pay amounts related to work performed prior to the termination (including the applicable portion of the base fee), certain termination-related costs, and, at certain stages of the work, the applicable portion of the at-risk fee. Bechtel may terminate the Bechtel Agreement under certain circumstances, including certain Vogtle Owner suspensions of work, certain breaches of the Bechtel Agreement by the Vogtle Owners, Vogtle Owner insolvency, and certain other events. Pursuant to the Loan Guarantee Agreement between the Company and the DOE, the Company is required to obtain the DOE's approval of the Bechtel Agreement prior to obtaining any further advances under the Loan Guarantee Agreement.

On November 2, 2017, the Vogtle Owners entered into an amendment to their joint ownership agreements for Plant Vogtle Units 3 and 4 (as amended, Vogtle Joint Ownership Agreements) to provide for, among other conditions, additional Vogtle Owner approval requirements. Pursuant to the Vogtle Joint Ownership Agreements, the holders of at least 90% of the ownership interests in Plant Vogtle Units 3 and 4 must vote to continue construction if certain adverse events occur, including (i) the bankruptcy of Toshiba; (ii) termination or rejection in bankruptcy of certain agreements, including the Vogtle Services Agreement or the Bechtel Agreement; (iii) the Georgia PSC or the Company determines that any of the Company's costs relating to the construction of Plant Vogtle Units 3 and 4 will not be recovered in retail rates because such costs are deemed unreasonable or imprudent; or (iv) an increase in the construction budget contained in the seventeenth VCM report of more than $1 billion or extension of the project schedule contained in the seventeenth VCM report of more than one year . In addition, pursuant to the Vogtle Joint Ownership Agreements, the required approval of holders of ownership interests in Plant Vogtle Units 3 and 4 is at least (i) 90% for a change of the primary construction contractor and (ii) 67% for material amendments to the Vogtle Services Agreement or agreements with Southern Nuclear or the primary construction contractor, including the Bechtel Agreement. The Vogtle Joint Ownership Agreements also confirm that the Vogtle Owners' sole recourse against the Company or Southern Nuclear for any action or inaction in connection with their performance as agent for the Vogtle Owners is limited to removal of the Company and/or Southern Nuclear as agent, except in cases of willful misconduct.

*Regulatory Matters*

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4 with a certified capital cost of $4.418 billion . In addition, in 2009 the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows the Company to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff up to the certified capital cost of $4.418 billion . As of December 31, 2017, the Company had recovered approximately $1.6 billion of financing costs. On January 30, 2018, the Company filed to decrease the NCCR tariff by approximately $50 million , effective April 1, 2018, pending Georgia PSC approval. The decrease reflects the payments received under the Guarantee Settlement Agreement, refunds to customers ordered by the Georgia PSC aggregating approximately $188 million (Customer Refunds), and the estimated effects of Tax Reform Legislation. The Customer Refunds were recognized as a regulatory liability as of December 31, 2017 and will be paid in three installments of $25 to each retail customer no later than the third quarter 2018.

The Company is required to file semi-annual VCM reports with the Georgia PSC by February 28 and August 31 each year. In October 2013, in connection with the eighth VCM report, the Georgia PSC approved a stipulation (2013 Stipulation) between the Company and the staff of the Georgia PSC to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate in accordance with the 2009 certification order until the completion of Plant Vogtle Unit 3, or earlier if deemed appropriate by the Georgia PSC and the Company.

On December 20, 2016, the Georgia PSC voted to approve a settlement agreement (Vogtle Cost Settlement Agreement) resolving certain prudency matters in connection with the fifteenth VCM report. On December 21, 2017, the Georgia PSC voted to approve (and issued its related order on January 11, 2018) certain recommendations made by the Company in the seventeenth VCM report and modifying the Vogtle Cost Settlement Agreement. The Vogtle Cost Settlement Agreement, as modified by the January 11, 2018 order, resolved the following regulatory matters related to Plant Vogtle Units 3 and 4: (i) none of the $3.3 billion of costs incurred through December 31, 2015 and reflected in the fourteenth VCM report should be disallowed from rate base on the basis of imprudence; (ii) the Contractor Settlement Agreement was reasonable and prudent and none of the amounts paid pursuant to the Contractor Settlement Agreement should be disallowed from rate base on the basis of imprudence; (iii) (a) capital costs incurred up to $5.680 billion would be presumed to be reasonable and prudent with the burden of proof on any party challenging such costs, (b) the Company would have the burden to show that any capital costs above $5.680 billion were prudent, and (c) a revised capital cost forecast of $7.3 billion (after reflecting the impact of payments received under the Guarantee Settlement Agreement and Customer Refunds) is found reasonable; (iv) construction of Plant Vogtle Units 3 and 4 should be completed, with Southern Nuclear serving as project manager and Bechtel as primary contractor; (v) approved and deemed reasonable the Company's revised schedule placing Plant Vogtle Units 3 and 4 in service in November 2021 and November 2022, respectively;

(vi) confirmed that the revised cost forecast does not represent a cost cap and that prudence decisions on cost recovery will be made at a later date, consistent with applicable Georgia law; (vii) reduced the ROE used to calculate the NCCR tariff (a) from 10.95% (the ROE rate setting point authorized by the Georgia PSC in the 2013 ARP) to 10.00% effective January 1, 2016, (b) from 10.00% to 8.30% , effective January 1, 2020, and (c) from 8.30% to 5.30% , effective January 1, 2021 (provided that the ROE in no case will be less than the Company's average cost of long-term debt); (viii) reduced the ROE used for AFUDC equity for Plant Vogtle Units 3 and 4 from 10.00% to the Company's average cost of long-term debt, effective January 1, 2018; and (ix) agreed that upon Unit 3 reaching commercial operation, retail base rates would be adjusted to include carrying costs on those capital costs deemed prudent in the Vogtle Cost Settlement Agreement. The January 11, 2018 order also stated that if Plant Vogtle Units 3 and 4 are not commercially operational by June 1, 2021 and June 1, 2022, respectively, the ROE used to calculate the NCCR tariff will be further reduced by 10 basis points each month (but not lower than the Company's average cost of long-term debt) until the respective unit is commercially operational. The ROE reductions negatively impacted earnings by approximately $20 million in 2016 and $25 million in 2017 and are estimated to have negative earnings impacts of approximately $120 million in 2018 and an aggregate of $585 million from 2019 to 2022. In its January 11, 2018 order, the Georgia PSC stated if other certain conditions and assumptions upon which the Company's seventeenth VCM report are based do not materialize, both the Company and the Georgia PSC reserve the right to reconsider the decision to continue construction.

On February 12, 2018, Georgia Interfaith Power & Light, Inc. and Partnership for Southern Equity, Inc. filed a petition appealing the Georgia PSC's January 11, 2018 order with the Fulton County Superior Court. The Company believes the appeal has no merit; however, an adverse outcome in this appeal could have a material impact on the Company's results of operations, financial condition, and liquidity.

The IRS allocated PTCs to each of Plant Vogtle Units 3 and 4, which originally required the applicable unit to be placed in service before 2021. Under the Bipartisan Budget Act of 2018, Plant Vogtle Units 3 and 4 continue to qualify for PTCs. The nominal value of the Company's portion of the PTCs is approximately $500 million per unit.

In its January 11, 2018 order, the Georgia PSC also approved $542 million of capital costs incurred during the seventeenth VCM reporting period (January 1, 2017 to June 30, 2017). The Georgia PSC has approved seventeen VCM reports covering the periods through June 30, 2017 , including total construction capital costs incurred through that date of $4.4 billion . The Company expects to file its eighteenth VCM report on February 28, 2018 requesting approval of approximately $450 million of construction capital costs (before payments received under the Guarantee Settlement Agreement and the Customer Refunds) incurred from July 1, 2017 through December 31, 2017 . The Company's CWIP balance for Plant Vogtle Units 3 and 4 was approximately $4.8 billion as of December 31, 2017 , or $3.3 billion net of payments received under the Guarantee Settlement Agreement and the Customer Refunds.

The ultimate outcome of these matters cannot be determined at this time.

*Cost and Schedule*

The Company's approximate proportionate share of the remaining estimated capital cost to complete Plant Vogtle Units 3 and 4 with in service dates of November 2021 and November 2022, respectively, is as follows:

| | | *(in billions)* |
|---|---|---|
| Project capital cost forecast | $ | 7.3 |
| Net investment as of December 31, 2017 | | (3.4) |
| **Remaining estimate to complete** | **$** | **3.9** |

Note: Excludes financing costs capitalized through AFUDC and is net of payments received under the Guarantee Settlement Agreement and the Customer Refunds.

The Company estimates that its financing costs for construction of Plant Vogtle Units 3 and 4 will total approximately $3.1 billion , of which $1.6 billion had been incurred through December 31, 2017 .

As construction continues, challenges with management of contractors, subcontractors, and vendors, labor productivity and availability, fabrication, delivery, assembly, and installation of plant systems, structures, and components (some of which are based on new technology and have not yet operated in the global nuclear industry at this scale), or other issues could arise and change the projected schedule and estimated cost.

There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4 at the federal and state level and additional challenges may arise. Processes are in place that are designed to assure compliance with the requirements specified in the Westinghouse Design Control Document and the combined construction and operating licenses, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance matters, including the timely resolution of Inspections, Tests, Analyses, and Acceptance Criteria and the related approvals by the NRC, may arise, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs.

The ultimate outcome of these matters cannot be determined at this time.

*Other Matters*

As of December 31, 2017 , the Company had borrowed $2.6 billion related to Plant Vogtle Units 3 and 4 costs through the Loan Guarantee Agreement and a multi-advance credit facility among the Company, the DOE, and the FFB, which provides for borrowings of up to $3.46 billion , subject to the satisfaction of certain conditions. On September 28, 2017, the DOE issued a conditional commitment to the Company for up to approximately $1.67 billion in additional guaranteed loans under the Loan Guarantee Agreement. This conditional commitment expires on June 30, 2018, subject to any further extension approved by the DOE. Final approval and issuance of these additional loan guarantees by the DOE cannot be assured and are subject to the negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions. See Note 6 under "DOE Loan Guarantee Borrowings" for additional information, including applicable covenants, events of default, mandatory prepayment events, and conditions to borrowing.

The ultimate outcome of these matters cannot be determined at this time.

**4. JOINT OWNERSHIP AGREEMENTS**

The Company and Alabama Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 MWs, as well as associated transmission facilities. SEGCO uses natural gas as the primary fuel source for 1,000 MWs of its generating capacity. The capacity of these units is sold equally to the Company and Alabama Power under a power contract. The Company and Alabama Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and an ROE. The Company's share of purchased power totaled $78 million in 2017 , $57 million in 2016 , and $78 million in 2015 and is included in purchased power, affiliates in the statements of income. The Company accounts for SEGCO using the equity method. See Note 7 under "Guarantees" for additional information.

The Company owns undivided interests in Plants Vogtle, Hatch, Wansley, and Scherer in varying amounts jointly with one or more of the following entities: Oglethorpe Power Corporation (OPC), MEAG Power, the City of Dalton, Georgia, acting by and through its Board of Water, Light, and Sinking Fund Commissioners, doing business as Dalton Utilities, Florida Power & Light Company, Jacksonville Electric Authority, and Gulf Power. Under these agreements, the Company has been contracted to operate and maintain the plants as agent for the co-owners and is jointly and severally liable for third party claims related to these plants. In addition, the Company jointly owns the Rocky Mountain pumped storage hydroelectric plant with OPC, which is the operator of the plant. In August 2016, the Company sold its 33% ownership interest in the Intercession City combustion turbine unit to Duke Energy Florida, LLC.

At December 31, 2017 , the Company's percentage ownership and investment (exclusive of nuclear fuel) in jointly-owned facilities in commercial operation with the above entities were as follows:

| Facility (Type) | Company Ownership | Plant in Service | Accumulated Depreciation | CWIP |
|---|---|---|---|---|
| | | | *(in millions)* | |
| Plant Vogtle (nuclear) | | | | |
| Units 1 and 2 | 45.7% | $ 3,564 | $ 2,141 | $ 70 |
| Plant Hatch (nuclear) | 50.1 | 1,321 | 595 | 87 |
| Plant Wansley (coal) | 53.5 | 1,053 | 335 | 72 |
| Plant Scherer (coal) | | | | |
| Units 1 and 2 | 8.4 | 261 | 93 | 8 |
| Unit 3 | 75.0 | 1,232 | 468 | 26 |
| Rocky Mountain (pumped storage) | 25.4 | 182 | 132 | — |

The Company's proportionate share of its plant operating expenses is included in the corresponding operating expenses in the statements of income and the Company is responsible for providing its own financing.

The Company also owns 45.7% of Plant Vogtle Units 3 and 4, which are currently under construction and had a CWIP balance of $3.3 billion as of December 31, 2017 . See Note 3 under "Retail Regulatory Matters – Nuclear Construction" for additional information.

## 5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and various combined and separate state income tax returns. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

### Federal Tax Reform Legislation

Following the enactment of Tax Reform Legislation, the SEC staff issued Staff Accounting Bulletin 118 – "Income Tax Accounting Implications of the Tax Cuts and Jobs Act" (SAB 118), which provides for a measurement period of up to one year from the enactment date to complete accounting under GAAP for the tax effects of the legislation. Due to the complex and comprehensive nature of the enacted tax law changes, and their application under GAAP, the Company considers all amounts recorded in the financial statements as a result of Tax Reform Legislation to be "provisional" as discussed in SAB 118 and subject to revision. The Company is awaiting additional guidance from industry and income tax authorities in order to finalize its accounting. The ultimate impact of Tax Reform Legislation on deferred income tax assets and liabilities and the related regulatory assets and liabilities cannot be determined at this time. See Note 3 under "Retail Regulatory Matters – Rate Plans" for additional information.

### Current and Deferred Income Taxes

Details of income tax provisions are as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| Federal – | | | |
| Current | **$ 256** | $ 391 | $ 515 |
| Deferred | **504** | 319 | 176 |
| | **760** | 710 | 691 |
| State – | | | |
| Current | **116** | 6 | 81 |
| Deferred | **(46)** | 64 | (3) |
| | **70** | 70 | 78 |
| Total | **$ 830** | $ 780 | $ 769 |

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Deferred tax liabilities – | | |
| Accelerated depreciation | $ 3,540 | $ 5,266 |
| Property basis differences | — | 957 |
| Employee benefit obligations | 287 | 428 |
| Premium on reacquired debt | 34 | 56 |
| Regulatory assets – | | |
| Storm damage reserves | 89 | 83 |
| Employee benefit obligations | 348 | 546 |
| Asset retirement obligations | 501 | 726 |
| Retired assets | 30 | 55 |
| Asset retirement obligations | 132 | 182 |
| Other | 100 | 83 |
| Total | 5,061 | 8,382 |
| Deferred tax assets – | | |
| Federal effect of state deferred taxes | 72 | 173 |
| Employee benefit obligations | 423 | 661 |
| Property basis differences | 92 | 105 |
| Other deferred costs | 69 | 100 |
| State investment tax credit carryforward | 318 | 201 |
| Federal tax credit carryforward | 97 | 84 |
| Unbilled fuel revenue | 26 | 47 |
| Regulatory liabilities associated with asset retirement obligations | 5 | 33 |
| Asset retirement obligations | 631 | 908 |
| Regulatory liability associated with Tax Reform Legislation (not subject to normalization) | 123 | — |
| Other | 30 | 70 |
| Total | 1,886 | 2,382 |
| Accumulated deferred income taxes | $ 3,175 | $ 6,000 |

The implementation of Tax Reform Legislation significantly reduced accumulated deferred income taxes, partially offset by bonus depreciation provisions of the Protecting Americans from Tax Hikes Act. Tax Reform Legislation also reduced tax-related regulatory assets and significantly increased tax-related regulatory liabilities.

At December 31, 2017 , tax-related regulatory assets to be recovered from customers were $521 million . These assets are primarily attributable to tax benefits flowed through to customers in prior years and deferred taxes previously recognized at rates lower than the current enacted tax law.

At December 31, 2017 , tax-related regulatory liabilities to be credited to customers were $3.2 billion . These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law.

In accordance with regulatory requirements, federal ITCs are deferred and, upon utilization, amortized over the average life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $10 million in each of 2017 , 2016 , and 2015 . State investment tax credits are recognized in the period in which the credits are generated and totaled $50 million in 2017 , $42 million in 2016 , and $33 million in 2015 . At December 31, 2017 , the Company had $87 million in federal ITC carryforwards that will expire by 2037 and $318 million in state ITC carryforwards that will expire between 2020 and 2028.

### Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| Federal statutory rate | **35.0 %** | 35.0 % | 35.0 % |
| State income tax, net of federal deduction | **2.0** | 2.1 | 2.5 |
| Non-deductible book depreciation | **0.7** | 0.8 | 1.2 |
| AFUDC equity | **(0.6)** | (0.8) | (0.7) |
| Tax Reform Legislation | **(0.4)** | — | — |
| Other | — | (0.4) | (0.4) |
| Effective income tax rate | **36.7 %** | 36.7 % | 37.6 % |

In March 2016, the FASB issued ASU 2016-09, which changed the accounting for income taxes for share-based payment award transactions. Entities are required to recognize all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation as income tax expense or benefit in the income statement. The adoption of ASU 2016-09 did not have a material impact on the Company's overall effective tax rate. See Note 1 under "Recently Issued Accounting Standards" for additional information.

### Unrecognized Tax Benefits

The Company had no material unrecognized tax benefits as of December 31, 2017 and no material changes in unrecognized tax benefits for any year presented.

The Company classifies interest on tax uncertainties as interest expense; however, the Company did not have any accrued interest or penalties for unrecognized tax benefits for any year presented.

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months. The settlement of federal and state audits could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2016. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2011.

## 6. FINANCING

### Securities Due Within One Year

A summary of scheduled maturities of securities due within one year at December 31 was as follows:

| | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| Senior notes | **$ 750** | $ 450 |
| Capital leases | **11** | 10 |
| Other long-term debt | **100** | — |
| Unamortized debt issuance expense | **(1)** | — |
| Total | **$ 860** | $ 460 |

Maturities through 2022 applicable to total long-term debt are as follows: $861 million in 2018 ; $513 million in 2019 ; $1.0 billion in 2020 ; $375 million in 2021 ; and $518 million in 2022 .

### Bank Term Loans

In June 2017, the Company entered into three floating rate bank loans in aggregate principal amounts of $50 million , $150 million , and $100 million , with maturity dates of December 1, 2017, May 31, 2018, and June 28, 2018, respectively, bearing interest based on one-month LIBOR. Also in June 2017, the Company borrowed $500 million pursuant to an uncommitted bank credit arrangement, which bears interest at a rate agreed upon by the Company and the bank from time to time and is payable on no less than 30 days ' demand by the bank. The proceeds from these bank loans were used to repay a portion of the Company's existing indebtedness and for working capital and other general corporate purposes, including the Company's continuous construction program.

In August 2017, the Company repaid $250 million of the $500 million aggregate principal amount outstanding pursuant to its uncommitted bank credit arrangement. Also in August 2017, the Company amended its $100 million floating rate bank loan to extend the maturity date from June 28, 2018 to October 26, 2018. In December 2017, the Company repaid the remaining $250 million aggregate principal amount outstanding pursuant to its uncommitted bank credit arrangement.

At December 31, 2017 , the Company had a total of $250 million in bank term loans outstanding. Subsequent to December 31, 2017 , the Company repaid its outstanding $150 million and $100 million floating rate bank loans due May 31, 2018 and October 26, 2018, respectively. At December 31, 2016 , the Company had no bank term loans outstanding.

The outstanding bank loans as of December 31, 2017 had covenants that limited debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes certain hybrid securities. At December 31, 2017, the Company was in compliance with its debt limits.

**Senior Notes**

In March 2017, the Company issued $450 million aggregate principal amount of Series 2017A 2.00% Senior Notes due March 30, 2020 and $400 million aggregate principal amount of Series 2017B 3.25% Senior Notes due March 30, 2027. The proceeds were used to repay a portion of the Company's short-term indebtedness and for general corporate purposes, including the Company's continuous construction program.

In August 2017, the Company issued $500 million aggregate principal amount of Series 2017C 2.00% Senior Notes due September 8, 2020. The proceeds were used to repay the Company's $50 million floating rate bank loan due December 1, 2017 and outstanding commercial paper borrowings and for general corporate purposes.

At December 31, 2017 and 2016 , the Company had $7.1 billion and $6.2 billion of senior notes outstanding, respectively, which included senior notes due within one year. These senior notes are effectively subordinated to all secured debt of the Company, which aggregated $2.8 billion at both December 31, 2017 and 2016 . As of December 31, 2017 , the Company's secured debt included borrowings of $2.6 billion guaranteed by the DOE and capital lease obligations of $154 million . As of December 31, 2016 , the Company's secured debt included borrowings of $2.6 billion guaranteed by the DOE and capital lease obligations of $169 million . See Note 7 and "DOE Loan Guarantee Borrowings" herein for additional information.

**Pollution Control Revenue Bonds**

Pollution control revenue bond obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bond obligations outstanding at both December 31, 2017 and 2016 was $1.8 billion .

In April 2017, the Company purchased and held $27 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), Fifth Series 1995. In October 2017, the Company remarketed these bonds to the public.

In August 2017, the Company purchased and held $38 million aggregate principal amount of Development Authority of Bartow County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Bowen Project), First Series 1997. In October 2017, the Company remarketed these bonds to the public.

**Junior Subordinated Notes**

At December 31, 2017 , the Company had a total of $270 million of junior subordinated notes outstanding. At December 31, 2016 , the Company had no junior subordinated notes outstanding.

In September 2017, the Company issued $270 million aggregate principal amount of Series 2017A 5.00% Junior Subordinated Notes due October 1, 2077. The proceeds were used to redeem all outstanding shares of the Company's preferred and preference stock. See "Outstanding Classes of Capital Stock" herein for additional information.

**DOE Loan Guarantee Borrowings**

Pursuant to the loan guarantee program established under Title XVII of the Energy Policy Act of 2005 (Title XVII Loan Guarantee Program), the Company and the DOE entered into the Loan Guarantee Agreement in 2014, under which the DOE agreed to guarantee the obligations of the Company under a note purchase agreement (FFB Note Purchase Agreement) among the DOE, the Company, and the FFB and a related promissory note (FFB Promissory Note). The FFB Note Purchase Agreement and the FFB Promissory Note provide for a multi-advance term loan facility (FFB Credit Facility), under which the Company may make term loan borrowings through the FFB.

On July 27, 2017, the Company entered into an amendment to the Loan Guarantee Agreement (LGA Amendment) in connection with the DOE's consent to the Company's entry into the Vogtle Services Agreement and the related intellectual property licenses (IP Licenses).

Under the terms of the Loan Guarantee Agreement, upon termination of the Vogtle 3 and 4 Agreement, further advances are conditioned upon the DOE's approval of any agreements entered into in replacement of the Vogtle 3 and 4 Agreement. Under the terms of the LGA Amendment, the Company will not request any advances unless and until certain conditions are satisfied, including (i) receipt of the DOE's approval of the Bechtel Agreement (together with the Vogtle Services Agreement and the IP Licenses, the Replacement EPC Arrangements) and (ii) the Company's entry into a further amendment to the Loan Guarantee Agreement with the DOE to reflect the Replacement EPC Arrangements.

Proceeds of advances made under the FFB Credit Facility are used to reimburse the Company for Eligible Project Costs. Aggregate borrowings under the FFB Credit Facility may not exceed the lesser of (i) 70% of Eligible Project Costs or (ii) approximately $3.46 billion .

On September 28, 2017, the DOE issued a conditional commitment to the Company for up to approximately $1.67 billion of additional guaranteed loans under the Loan Guarantee Agreement. This conditional commitment expires on June 30, 2018, subject to any further extension approved by the DOE. Final approval and issuance of these additional loan guarantees by the DOE cannot be assured and are subject to the negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions.

All borrowings under the FFB Credit Facility are full recourse to the Company, and the Company is obligated to reimburse the DOE for any payments the DOE is required to make to the FFB under the guarantee. The Company's reimbursement obligations to the DOE are full recourse and secured by a first priority lien on (i) the Company's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) the Company's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. There are no restrictions on the Company's ability to grant liens on other property.

In addition to the conditions described above, future advances are subject to satisfaction of customary conditions, as well as certification of compliance with the requirements of the Title XVII Loan Guarantee Program, including accuracy of project-related representations and warranties, delivery of updated project-related information, and evidence of compliance with the prevailing wage requirements of the Davis-Bacon Act of 1931, as amended, and certification from the DOE's consulting engineer that proceeds of the advances are used to reimburse Eligible Project Costs.

Upon satisfaction of all conditions described above, advances may be requested under the FFB Credit Facility on a quarterly basis through 2020. The final maturity date for each advance under the FFB Credit Facility is February 20, 2044. Interest is payable quarterly and principal payments will begin on February 20, 2020. Borrowings under the FFB Credit Facility will bear interest at the applicable U.S. Treasury rate plus a spread equal to 0.375% .

At both December 31, 2017 and 2016 , the Company had $2.6 billion of borrowings outstanding under the FFB Credit Facility.

Under the Loan Guarantee Agreement, the Company is subject to customary borrower affirmative and negative covenants and events of default. In addition, the Company is subject to project-related reporting requirements and other project-specific covenants and events of default.

In the event certain mandatory prepayment events occur, the FFB's commitment to make further advances under the FFB Credit Facility will terminate and the Company will be required to prepay the outstanding principal amount of all borrowings under the FFB Credit Facility over a period of five years (with level principal amortization). Among other things, these mandatory prepayment events include (i) the termination of the Vogtle Services Agreement or rejection of the Vogtle Services Agreement in bankruptcy if the Company does not maintain access to intellectual property rights under the IP Licenses; (ii) a decision by the Company not to continue construction of Plant Vogtle Units 3 and 4; (iii) cancellation of Plant Vogtle Units 3 and 4 by the Georgia PSC, or by the Company if authorized by the Georgia PSC; and (iv) cost disallowances by the Georgia PSC that could have a material adverse effect on completion of Plant Vogtle Units 3 and 4 or the Company's ability to repay the outstanding borrowings under the FFB Credit Facility. Under certain circumstances, insurance proceeds and any proceeds from an event of taking must be applied to immediately prepay outstanding borrowings under the FFB Credit Facility. In addition, if the Company discontinues construction of Plant Vogtle Units 3 and 4, the Company would be obligated to immediately repay a portion of the outstanding borrowings under the FFB Credit Facility to the extent such outstanding borrowings exceed 70% of Eligible Project Costs, net of the proceeds received by the Company under the Guarantee Settlement Agreement. The Company also may voluntarily prepay outstanding borrowings under the FFB Credit Facility. Under the FFB Credit Facility, any prepayment (whether mandatory or optional) will be made with a make-whole premium or discount, as applicable.

In connection with any cancellation of Plant Vogtle Units 3 and 4 that results in a mandatory prepayment event, the DOE may elect to continue construction of Plant Vogtle Units 3 and 4. In such an event, the DOE will have the right to assume the Company's rights and obligations under the principal agreements relating to Plant Vogtle Units 3 and 4 and to acquire all or a portion of the Company's ownership interest in Plant Vogtle Units 3 and 4.

### Capital Leases

Assets acquired under capital leases are recorded in the balance sheets as utility plant in service, and the related obligations are classified as long-term debt. At December 31, 2017 and 2016 , the Company had a capital lease asset for its corporate headquarters building of $61 million , with accumulated depreciation at December 31, 2017 and 2016 of $39 million and $33 million , respectively. At December 31, 2017 and 2016 , the capitalized lease obligation was $22 million and $28 million , respectively, with an annual interest rate of 7.9% . For ratemaking purposes, the Georgia PSC has allowed the lease payments in cost of service with no return on the capital lease asset. The difference between the depreciation and the lease payments allowed for ratemaking purposes is recovered as operating expenses as ordered by the Georgia PSC. The annual operating expense incurred for this capital lease was not material for any year presented.

At December 31, 2017 and 2016 , the Company had capital lease assets related to two PPAs with Southern Power of $144 million and $149 million , respectively, with accumulated amortization at December 31, 2017 and 2016 of $29 million and $19 million , respectively. At December 31, 2017 and 2016 , the related capitalized lease obligations were $132 million and $141 million , respectively. The annual interest rates range from 10% to 12% for these two capital lease PPAs. For ratemaking purposes, the Georgia PSC has included the capital lease asset amortization in cost of service and the interest in the Company's cost of debt. See Note 1 under "Affiliate Transactions" and Note 7 under "Fuel and Purchased Power Agreements" for additional information.

### Assets Subject to Lien

See "DOE Loan Guarantee Borrowings" above for information regarding certain borrowings of the Company that are secured by a first priority lien on (i) the Company's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) the Company's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4.

See "Capital Leases" above for information regarding certain assets held under capital leases.

### Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company has shares of its common stock outstanding. In October 2017, the Company redeemed all 1.8 million shares ( $45 million aggregate liquidation amount) of its 6.125% Series Class A Preferred Stock and 2.25 million shares ( $225 million aggregate liquidation amount) of its 6.50% Series 2007A Preference Stock. No shares of preferred stock, Class A preferred stock, or preference stock were outstanding at December 31, 2017 .

### Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

### Bank Credit Arrangements

At December 31, 2017 , the Company had a $1.75 billion committed credit arrangement with banks, of which $1.73 billion was unused. In May 2017, the Company amended its multi-year credit arrangement which, among other things, extended the maturity date from 2020 to 2022.

This bank credit arrangement requires payment of commitment fees based on the unused portion of the commitments. Commitment fees average less than $^1/_4$ of 1% for the Company.

This bank credit arrangement contains a covenant that limits the Company's debt levels to 65% of total capitalization, as defined in the agreement. For purposes of this definition, debt excludes certain hybrid securities. At December 31, 2017 , the Company was in compliance with the debt limit covenant.

Subject to applicable market conditions, the Company expects to renew this bank credit arrangement, as needed, prior to expiration. In connection therewith, the Company may extend the maturity date and/or increase or decrease the lending commitments thereunder.

A portion of the $1.73 billion unused credit with banks is allocated to provide liquidity support to the Company's pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2017 was $550 million as compared to $868 million at December 31, 2016 . In addition, at December 31, 2017 , the Company had $469 million of pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

The Company makes short-term borrowings primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangement described above. Commercial paper is included in notes payable in the balance sheets.

Details of short-term borrowings outstanding were as follows:

| | Short-term Debt at the End of the Period | |
|---|---|---|
| | **Amount Outstanding** | **Weighted Average Interest Rate** |
| | *(in millions)* | |
| **December 31, 2017:** | | |
| Short-term bank debt | **$ 150** | **2.2%** |
| **December 31, 2016:** | | |
| Commercial paper | $ 392 | 1.1% |

## 7. COMMITMENTS

### Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil and nuclear fuel which are not recognized on the balance sheets. In 2017 , 2016 , and 2015 , the Company incurred fuel expense of $1.7 billion , $1.8 billion , and $2.0 billion , respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

The Company has commitments regarding a portion of a 5% interest in the original cost of Plant Vogtle Units 1 and 2 owned by MEAG Power that are in effect until the latter of the retirement of the plant or the latest stated maturity date of MEAG Power's bonds issued to finance such ownership interest. The payments for capacity are required whether or not any capacity is available. The energy cost is a function of each unit's variable operating costs. Portions of the capacity payments relate to costs in excess of MEAG Power's Plant Vogtle Units 1 and 2 allowed investment for ratemaking purposes. The present value of these portions at the time of the disallowance was written off. Generally, the cost of such capacity and energy is included in purchased power, non-affiliates in the statements of income. Capacity payments totaled $9 million , $11 million , and $10 million in 2017 , 2016 , and 2015 , respectively.

**NOTES (continued)**
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The Company has also entered into various long-term PPAs, some of which are accounted for as capital or operating leases. Total capacity expense under PPAs accounted for as operating leases was $199 million , $217 million , and $203 million for 2017 , 2016 , and 2015 , respectively. Contingent rent expense under energy-only solar PPAs of $73 million , $39 million , and $8 million for 2017 , 2016 , and 2015 , respectively, was recognized as services were performed. Estimated total long-term obligations at December 31, 2017 were as follows:

| | Affiliate Capital Leases | Affiliate Operating Leases | Non-Affiliate Operating Leases | Vogtle Units 1 and 2 Capacity Payments | Total |
|---|---|---|---|---|---|
| | | | *(in millions)* | | |
| 2018 | $ 23 | $ 62 | $ 127 | $ 7 | $ 219 |
| 2019 | 23 | 63 | 128 | 6 | 220 |
| 2020 | 23 | 65 | 124 | 4 | 216 |
| 2021 | 24 | 66 | 125 | 5 | 220 |
| 2022 | 24 | 67 | 126 | 4 | 221 |
| 2023 and thereafter | 182 | 412 | 773 | 38 | 1,405 |
| Total | $ 299 | $ 735 | $ 1,403 | $ 64 | $ 2,501 |
| Less: amounts representing executory costs [(a)] | 45 | | | | |
| Net minimum lease payments | 254 | | | | |
| Less: amounts representing interest [(b)] | 120 | | | | |
| Present value of net minimum lease payments | $ 134 | | | | |

(a) Executory costs such as taxes, maintenance, and insurance (including the estimated profit thereon) a re estimated and included in total minimum lease payments.

(b) Calculated using an adjusted incremental borrowing rate to reduce the present value of the net minimum lease payments to fair value.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other traditional electric operating companies and Southern Power. Under these agreements, each of the traditional electric operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional electric operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

**Operating Leases**

The Company has entered into operating leases with Southern Linc and third parties for the use of cellular tower space. Substantially all of these agreements have initial terms ranging from five to 10 years and renewal options of up to 20 years . The Company has also entered into rental agreements for facilities, railcars, and other equipment with various terms and expiration dates. Total rent expense was $31 million , $28 million , and $29 million for 2017 , 2016 , and 2015 , respectively. The Company includes any step rents, fixed escalations, and lease concessions in its computation of minimum lease payments.

As of December 31, 2017 , estimated minimum lease payments under operating leases were as follows:

| | Minimum Lease Payments | | |
|---|---|---|---|
| | Affiliate Operating Leases [(a)] | Non-Affiliate Operating Leases [(b)] | Total |
| | (in millions) | | |
| 2018 | $ 10 | $ 14 | $ 24 |
| 2019 | 11 | 11 | 22 |
| 2020 | 11 | 9 | 20 |
| 2021 | 9 | 8 | 17 |
| 2022 | 8 | 6 | 14 |
| 2023 and thereafter | 33 | 11 | 44 |
| Total | $ 82 | $ 59 | $ 141 |

(a) Includes operating leases for cellular tower space.

(b) Includes operating leases for cellular tower space, facilities, railcars, and other equipment.

Railcar minimum lease payments are disclosed at 100% of railcar lease obligations; however, a portion of these obligations is shared with the joint owners of Plants Scherer and Wansley. A majority of the rental expenses related to the railcar leases are recoverable through the fuel cost recovery clause as ordered by the Georgia PSC and the remaining portion is recovered through base rates.

In addition to the above rental commitments, the Company has obligations upon expiration of certain railcar leases with respect to the residual value of the leased property. These leases have terms expiring through 2024 with maximum obligations under these leases of $32 million . At the termination of the leases, the Company may either renew the lease, exercise its purchase option, or the property can be sold to a third party. The Company expects that the fair market value of the leased property would reduce the Company's payments under the residual value obligations.

### Guarantees

Alabama Power has guaranteed the obligations of SEGCO for $25 million of pollution control revenue bonds issued in 2001, which mature in June 2019, and also $100 million of senior notes issued in 2013, which mature in December 2018. The Company has agreed to reimburse Alabama Power for the pro rata portion of such obligations corresponding to the Company's then proportionate ownership of SEGCO's stock if Alabama Power is called upon to make such payment under its guarantee. See Note 4 for additional information.

In addition, in 2013, the Company entered into an agreement that requires the Company to guarantee certain payments of a gas supplier for Plant McIntosh for a period up to 15 years . The guarantee is expected to be terminated if certain events occur within one year of the initial gas deliveries in 2018 . In the event the gas supplier defaults on payments, the maximum potential exposure under the guarantee is approximately $43 million .

As discussed earlier in this Note under "Operating Leases," the Company has entered into certain residual value guarantees related to railcar leases.

## 8. STOCK COMPENSATION

### Stock-Based Compensation

Stock-based compensation primarily in the form of Southern Company performance share units and restricted stock units may be granted through the Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. In 2015 and 2016, stock-based compensation consisted exclusively of performance share units. Beginning in 2017, stock-based compensation granted to employees includes restricted stock units in addition to performance share units. Prior to 2015, stock-based compensation also included stock options. As of December 31, 2017 , there were 895 current and former employees participating in the stock option, performance share unit, and restricted stock unit programs.

***Performance Share Units***

Performance share units granted to employees vest at the end of a three -year performance period. All unvested performance share units vest immediately upon a change in control where Southern Company is not the surviving corporation. Shares of Southern Company common stock are delivered to employees at the end of the performance period with the number of shares issued ranging from 0% to 200% of the target number of performance share units granted, based on achievement of the performance goals established by the Compensation Committee of the Southern Company Board of Directors.

Southern Company issues performance share units with performance goals based on three performance goals to employees. These include performance share units with performance goals based on the total shareholder return (TSR) for Southern Company common stock during the three -year performance period as compared to a group of industry peers, performance share units with performance goals based on Southern Company's cumulative earnings per share (EPS) over the performance period, and performance share units with performance goals based on Southern Company's equity-weighted ROE over the performance period.

In 2015 and 2016, the EPS-based and ROE-based awards each represented 25% of the total target grant date fair value of the performance share unit awards granted. The remaining 50% of the total target grant date fair value consisted of TSR-based awards. Beginning in 2017, the total target grant date fair value of the stock compensation awards granted was comprised 20% each of EPS-based awards and ROE-based awards and 30% each of TSR-based awards and restricted stock units.

The fair value of TSR-based performance share unit awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's common stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three -year performance period without remeasurement.

The fair values of the EPS-based awards and the ROE-based awards are based on the closing stock price of Southern Company common stock on the date of the grant. Compensation expense for the EPS-based and ROE-based awards is generally recognized ratably over the three -year performance period initially assuming a 100% payout at the end of the performance period. Employees become immediately vested in the TSR-based performance share units, along with the EPS-based and ROE-based awards, upon retirement. As a result, compensation expense for employees that are retirement eligible at the grant date is recognized immediately while compensation expense for employees that become retirement eligible during the vesting period is recognized over the period from grant date to the date of retirement eligibility. The expected payout related to the EPS-based and ROE-based awards is reevaluated annually with expense recognized to date increased or decreased based on the number of shares currently expected to be issued. Unlike the TSR-based awards, the compensation expense ultimately recognized for the EPS-based awards and the ROE-based awards will be based on the actual number of shares issued at the end of the performance period.

For the years ended December 31, 2017 , 2016 , and 2015 , employees of the Company were granted performance share units of 138,102 , 261,434 , and 236,804 , respectively. The weighted average grant-date fair value of TSR-based performance share units granted during 2017 , 2016 , and 2015 , determined using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period, was $49.27 , $45.17 , and $46.41 , respectively. The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2017 , 2016 , and 2015 was $49.22 , $48.84 , and $47.78 , respectively.

For the years ended December 31, 2017 , 2016 , and 2015 , total compensation cost for performance share units recognized in income was $10 million , $15 million , and $15 million , respectively, with the related tax benefit also recognized in income of $4 million , $6 million , and $6 million , respectively. The compensation cost related to the grant of Southern Company performance share units to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2017 , $3 million of total unrecognized compensation cost related to performance share award units will be recognized over a weighted-average period of approximately 21 months .

***Restricted Stock Units***

Beginning in 2017, stock-based compensation granted to employees included restricted stock units in addition to performance share units. One-third of the restricted stock units granted to employees vest each year throughout a three -year service period. All unvested restricted stock units vest immediately upon a change in control where Southern Company is not the surviving corporation. Shares of Southern Company common stock are delivered to employees at the end of the vesting period.

The fair value of restricted stock units is based on the closing stock price of Southern Company common stock on the date of the grant. Since one-third of the restricted stock units vest each year throughout a three -year service period, compensation expense for restricted stock unit awards is generally recognized over the corresponding one -, two -, or three -year period. Employees become immediately vested in the restricted stock units upon retirement. As a result, compensation expense for employees that are retirement eligible at the grant date is recognized immediately while compensation expense for employees that become retirement eligible during the vesting period is recognized over the period from grant date to the date of retirement eligibility.

For the year ended December 31, 2017, employees of the Company were granted 59,218 restricted stock units. The weighted average grant-date fair value of restricted stock units granted during 2017 was $49.22 .

For the year ended December 31, 2017, total compensation cost for restricted stock units recognized in income was $3 million with the related tax benefit also recognized in income of $1 million . As of December 31, 2017, $1 million of total unrecognized compensation cost related to restricted stock units will be recognized over a weighted-average period of approximately 13 months .

***Stock Options***

In 2015, Southern Company discontinued the granting of stock options. Stock options expire no later than 10 years after the grant date and the latest possible exercise will occur no later than November 2024.

The compensation cost related to the grant of Southern Company stock options to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. Compensation cost and related tax benefits recognized in the Company's financial statements were not material for any year presented. As of December 31, 2017 , all compensation cost related to stock option awards has been recognized.

The total intrinsic value of options exercised during the years ended December 31, 2017 , 2016 , and 2015 was $13 million , $18 million , and $9 million , respectively. No cash proceeds are received by the Company upon the exercise of stock options. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $5 million , $7 million , and $4 million for the years ended December 31, 2017 , 2016 , and 2015 , respectively. Prior to the adoption of ASU 2016-09 in 2016, the excess tax benefits related to the exercise of stock options were recognized in the Company's financial statements with a credit to equity. Upon the adoption of ASU 2016-09, beginning in 2016, all tax benefits related to the exercise of stock options are recognized in income. As of December 31, 2017 , the aggregate intrinsic value for the options outstanding and exercisable was $30 million .

## 9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Plant Hatch and Plant Vogtle Units 1 and 2. The Act provides funds up to $13.4 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $450 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. The Company could be assessed up to $127 million per incident for each licensed reactor it operates but not more than an aggregate of $19 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company, based on its ownership and buyback interests in all licensed reactors, is $247 million per incident, but not more than an aggregate of $37 million to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years . The next scheduled adjustment is due no later than September 10, 2018. See Note 4 for additional information on joint ownership agreements.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $1.5 billion for members' operating nuclear generating facilities. Additionally, the Company has NEIL policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $1.25 billion for nuclear losses and policies providing coverage up to $750 million for non-nuclear losses in excess of the $1.5 billion primary coverage.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks , with a maximum per occurrence per unit limit of $490 million . After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted. The Company purchases limits based on the projected full cost of replacement power, subject to ownership limitations, and has elected a 12-week deductible waiting period for each facility.

A builders' risk property insurance policy has been purchased from NEIL for the construction of Plant Vogtle Units 3 and 4. This policy provides the Vogtle Owners up to $2.75 billion for accidental property damage occurring during construction.

Under each of the NEIL policies, members are subject to assessments each year if losses exceed the accumulated funds available to the insurer. The maximum annual assessments for the Company as of December 31, 2017 under the NEIL policies would be $81 million .

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12 -month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by the Company and could have a material effect on the Company's financial condition and results of operations.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

## 10. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 2017 , assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

| | Fair Value Measurements Using | | | |
|---|---|---|---|---|
| As of December 31, 2017: | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Total |
| | | *(in millions)* | | |
| Assets: | | | | |
| Energy-related derivatives | $ — | $ 6 | $ — | $ 6 |
| Nuclear decommissioning trusts: (*) | | | | |
| Domestic equity | 248 | 1 | — | 249 |
| Foreign equity | — | 166 | — | 166 |
| U.S. Treasury and government agency securities | — | 227 | — | 227 |
| Municipal bonds | — | 68 | — | 68 |
| Corporate bonds | — | 155 | — | 155 |
| Mortgage and asset backed securities | — | 40 | — | 40 |
| Other | 12 | 12 | — | 24 |
| Cash equivalents | 690 | — | — | 690 |
| Total | $ 950 | $ 675 | $ — | $ 1,625 |
| Liabilities: | | | | |
| Energy-related derivatives | $ — | $ 19 | $ — | $ 19 |
| Interest rate derivatives | — | 5 | — | 5 |
| Total | $ — | $ 24 | $ — | $ 24 |

(*) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, currencies, and payables related to pending investment purchases and the securities lending program. See Note 1 under "Nuclear Decommissioning" for additional information.

**NOTES (continued)**
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As of December 31, 2016 , assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

| | Fair Value Measurements Using | | | |
|---|---|---|---|---|
| **As of December 31, 2016:** | **Quoted Prices in Active Markets for Identical Assets (Level 1)** | **Significant Other Observable Inputs (Level 2)** | **Significant Unobservable Inputs (Level 3)** | **Total** |
| | | *(in millions)* | | |
| Assets: | | | | |
| Energy-related derivatives | $ — | $ 44 | $ — | $ 44 |
| Interest rate derivatives | — | 2 | — | 2 |
| Nuclear decommissioning trusts: (*) | | | | |
| Domestic equity | 204 | 1 | — | 205 |
| Foreign equity | — | 121 | — | 121 |
| U.S. Treasury and government agency securities | — | 71 | — | 71 |
| Municipal bonds | — | 73 | — | 73 |
| Corporate bonds | — | 164 | — | 164 |
| Mortgage and asset backed securities | — | 164 | — | 164 |
| Other | 11 | 5 | — | 16 |
| Total | $ 215 | $ 645 | $ — | $ 860 |
| Liabilities: | | | | |
| Energy-related derivatives | $ — | $ 8 | $ — | $ 8 |
| Interest rate derivatives | — | 3 | — | 3 |
| Total | $ — | $ 11 | $ — | $ 11 |

(*) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, currencies, and payables related to pending investment purchases and the securities lending program. See Note 1 under "Nuclear Decommissioning" for additional information.

**Valuation Methodologies**

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard over-the-counter products that are valued using observable market data and assumptions commonly used by market participants. The fair value of interest rate derivatives reflects the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk, and occasionally, implied volatility of interest rate options. The interest rate derivatives are categorized as Level 2 under Fair Value Measurements as these inputs are based on observable data and valuations of similar instruments. See Note 11 for additional information on how these derivatives are used.

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. For fair value measurements of the investments within the nuclear decommissioning trusts, external pricing vendors are designated for each asset class with each security specifically assigned a primary pricing source. For investments held within commingled funds, fair value is determined at the end of each business day through the net asset value, which is established by obtaining the underlying securities' individual prices from the primary pricing source. A market price secured from the primary source vendor is then evaluated by management in its valuation of the assets within the trusts. As a general approach, fixed income market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information, including live trading levels and pricing analysts' judgments, are also obtained when available. See Note 1 under "Nuclear Decommissioning" for additional information.

As of December 31, 2017 and 2016 , other financial instruments for which the carrying amount did not equal fair value were as follows:

| | Carrying Amount | Fair Value |
|---|---|---|
| | *(in millions)* | |
| Long-term debt, including securities due within one year: | | |
| **2017** | **$ 11,777** | **$ 12,531** |
| 2016 | $ 10,516 | $ 11,034 |

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on current rates available to the Company.

## 11. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a net basis. See Note 10 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

### Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in energy-related commodity prices. The Company manages a fuel-hedging program through the use of financial derivative contracts, which is expected to continue to mitigate price volatility. At December 31, 2017 and 2016 , substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were related to the Company's fuel-hedging program. Effective January 1, 2016, the Georgia PSC approved changes to the Company's hedging program allowing it to use an array of derivative instruments within a 48 -month time horizon.

Energy-related derivative contracts are accounted for under one of two methods:

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging program, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery mechanism.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2017 , the net volume of energy-related derivative contracts for natural gas positions totaled 163 million mmBtu, all of which expire by 2021 , which is the longest hedge date.

In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The expected volume of natural gas subject to such a feature is 10 million mmBtu for the Company.

### Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings, with any ineffectiveness recorded directly to earnings. At December 31, 2017 , there were no cash flow hedges outstanding. Derivatives related to fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains and losses and the hedged items' fair value gains and losses attributable to interest rate risk are both recorded directly to earnings, providing an offset, with any differences representing ineffectiveness.

At December 31, 2017 , the following interest rate derivatives were outstanding:

| | Notional Amount | Interest Rate Received | Weighted Average Interest Rate Paid | Hedge Maturity Date | Fair Value Gain (Loss) December 31, 2017 |
|---|---|---|---|---|---|
| | *(in millions)* | | | | *(in millions)* |
| ***Fair Value Hedges of Existing Debt*** | | | | | |
| | $ 250 | 5.40% | 3-month LIBOR + 4.02% | June 2018 | $ — |
| | 500 | 1.95% | 3-month LIBOR + 0.76% | December 2018 | (3) |
| | 200 | 4.25% | 3-month LIBOR + 2.46% | December 2019 | (1) |
| Total | $ 950 | | | | $ (4) |

The estimated pre-tax gains (losses) related to interest rate derivatives that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2018 total $(4) million . Deferred gains and losses related to interest rate derivative settlements of cash flow hedges are expected to be amortized into earnings through 2037 .

**Derivative Financial Statement Presentation and Amounts**

The Company enters into energy-related and interest rate derivative contracts that may contain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Fair value amounts of derivative assets and liabilities on the balance sheets are presented net to the extent that there are netting arrangements or similar agreements with the counterparties.

At December 31, 2017 and 2016 , the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

| | 2017 | | 2016 | |
|---|---|---|---|---|
| **Derivative Category and Balance Sheet Location** | **Assets** | **Liabilities** | Assets | Liabilities |
| | *(in millions)* | | | |
| **Derivatives designated as hedging instruments for regulatory purposes** | | | | |
| Energy-related derivatives: | | | | |
| Other current assets/Other current liabilities | **$ 2** | **$ (9)** | $ 30 | $ 1 |
| Other deferred charges and assets/Other deferred credits and liabilities | **4** | **(10)** | 14 | 7 |
| **Total derivatives designated as hedging instruments for regulatory purposes** | **$ 6** | **$ (19)** | $ 44 | $ 8 |
| **Derivatives designated as hedging instruments in cash flow and fair value hedges** | | | | |
| Interest rate derivatives: | | | | |
| Other current assets/Other current liabilities | **$ —** | **$ (4)** | $ 2 | $ — |
| Other deferred charges and assets/Other deferred credits and liabilities | **—** | **(1)** | — | 3 |
| **Total derivatives designated as hedging instruments in cash flow and fair value hedges** | **$ —** | **$ (5)** | $ 2 | $ 3 |
| **Gross amounts recognized** | **$ 6** | **$ (24)** | $ 46 | $ 11 |
| **Gross amounts offset** | **$ (6)** | **$ 6** | $ (8) | $ (8) |
| **Net amounts recognized in the Balance Sheets** | **$ —** | **$ (18)** | $ 38 | $ 3 |

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2017 and 2016 .

At December 31, 2017 and 2016 , the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivatives designated as regulatory hedging instruments and deferred were as follows:

| | Unrealized Losses | | | Unrealized Gains | | |
|---|---|---|---|---|---|---|
| **Derivative Category** | **Balance Sheet Location** | **2017** | 2016 | **Balance Sheet Location** | **2017** | 2016 |
| | | *(in millions)* | | | *(in millions)* | |
| Energy-related derivatives: | Other regulatory assets, current | **$ (7)** | $ — | Other regulatory liabilities, current | **$ —** | $ 29 |
| | Other regulatory assets, deferred | **(6)** | — | Other deferred credits and liabilities | **—** | 7 |
| **Total energy-related derivative gains (losses)** | | **$ (13)** | $ — | | **$ —** | $ 36 |

For the years ended December 31, 2017 , 2016 , and 2015 , the pre-tax effects of interest rate derivatives designated as cash flow hedging instruments on the statements of income were as follows:

| **Derivatives in Cash Flow Hedging Relationships** | **Gain (Loss) Recognized in OCI on Derivative (Effective Portion)** | | | **Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)** | | | |
|---|---|---|---|---|---|---|---|
| | | | | | **Amount** | | |
| **Derivative Category** | **2017** | 2016 | 2015 | **Statements of Income Location** | **2017** | 2016 | 2015 |
| | | *(in millions)* | | | | *(in millions)* | |
| Interest rate derivatives | **$ 1** | $ — | $ (15) | Interest expense, net of amounts capitalized | **$ (4)** | $ (4) | $ (3) |

For the years ended December 31, 2017 , 2016 , and 2015 , the pre-tax effects of interest rate derivatives designated as fair value hedging instruments on the statements of income were immaterial on a gross basis for the Company. Furthermore, the pre-tax effect of interest rate derivatives designated as fair value hedging instruments on the Company's statements of income were offset by changes to the carrying value of long-term debt. The gains and losses related to interest rate derivative settlements of fair value hedges are recorded directly to earnings.

There was no ineffectiveness recorded in earnings for any period presented. The pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was immaterial for all years presented.

**Contingent Features**

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2017 , the Company had no collateral posted with derivative counterparties to satisfy these arrangements.

At December 31, 2017 , the fair value of derivative liabilities with contingent features was $2 million . However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $12 million , and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

## 12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2017 and 2016 is as follows:

| Quarter Ended | Operating Revenues | Operating Income | Net Income After Dividends on Preferred and Preference Stock |
|---|---|---|---|
| | | *(in millions)* | |
| **March 2017** | **$ 1,832** | **$ 501** | **$ 260** |
| **June 2017** | **2,048** | **639** | **347** |
| **September 2017** | **2,546** | **1,034** | **580** |
| **December 2017** | **1,884** | **470** | **227** |
| | | | |
| March 2016 | $ 1,872 | $ 509 | $ 269 |
| June 2016 | 2,051 | 656 | 349 |
| September 2016 | 2,698 | 1,054 | 599 |
| December 2016 | 1,762 | 258 | 113 |

The Company's business is influenced by seasonal weather conditions.

**SELECTED FINANCIAL AND OPERATING DATA 2013 - 2017**
**Georgia Power Company 2017 Annual Report**

| | 2017 | 2016 | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|
| **Operating Revenues (in millions)** | **$ 8,310** | $ 8,383 | $ 8,326 | $ 8,988 | $ 8,274 |
| **Net Income After Dividends on Preferred and Preference Stock (in millions)** | **$ 1,414** | $ 1,330 | $ 1,260 | $ 1,225 | $ 1,174 |
| **Cash Dividends on Common Stock (in millions)** | **$ 1,281** | $ 1,305 | $ 1,034 | $ 954 | $ 907 |
| **Return on Average Common Equity (percent)** | **12.15** | 12.05 | 11.92 | 12.24 | 12.45 |
| **Total Assets (in millions)** [(a)(b)] | **$ 36,779** | $ 34,835 | $ 32,865 | $ 30,872 | $ 28,776 |
| **Gross Property Additions (in millions)** | **$ 1,080** | $ 2,314 | $ 2,332 | $ 2,146 | $ 1,906 |
| **Capitalization (in millions):** | | | | | |
| Common stock equity | **$ 11,931** | $ 11,356 | $ 10,719 | $ 10,421 | $ 9,591 |
| Preferred and preference stock | **—** | 266 | 266 | 266 | 266 |
| Long-term debt [(a)] | **11,073** | 10,225 | 9,616 | 8,563 | 8,571 |
| Total (excluding amounts due within one year) | **$ 23,004** | $ 21,847 | $ 20,601 | $ 19,250 | $ 18,428 |
| **Capitalization Ratios (percent):** | | | | | |
| Common stock equity | **51.9** | 52.0 | 52.0 | 54.1 | 52.0 |
| Preferred and preference stock | **—** | 1.2 | 1.3 | 1.4 | 1.4 |
| Long-term debt [(a)] | **48.1** | 46.8 | 46.7 | 44.5 | 46.6 |
| Total (excluding amounts due within one year) | **100.0** | 100.0 | 100.0 | 100.0 | 100.0 |
| **Customers (year-end):** | | | | | |
| Residential | **2,185,782** | 2,155,945 | 2,127,658 | 2,102,673 | 2,080,358 |
| Commercial [(c)] | **308,939** | 305,488 | 302,891 | 300,186 | 297,493 |
| Industrial [(c)] | **10,644** | 10,537 | 10,429 | 10,192 | 10,063 |
| Other | **9,766** | 9,585 | 9,261 | 9,003 | 8,623 |
| Total | **2,515,131** | 2,481,555 | 2,450,239 | 2,422,054 | 2,396,537 |
| **Employees (year-end)** | **6,986** | 7,527 | 7,989 | 7,909 | 7,886 |

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $124 million and $62 million is reflected for years 2014 and 2013, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(b) A reclassification of deferred tax assets from Total Assets of $34 million and $68 million is reflected for years 2014 and 2013, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(c) A reclassification of customers from commercial to industrial is reflected for years 2013-2015 to be consistent with the rate structure approved by the Georgia PSC. The impact to operating revenues, kilowatt-hour sales, and average revenue per kilowatt-hour by class is not material.

**SELECTED FINANCIAL AND OPERATING DATA 2013 - 2017 (continued)**
**Georgia Power Company 2017 Annual Report**

| | 2017 | 2016 | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|
| **Operating Revenues (in millions):** | | | | | |
| Residential | $ 3,236 | $ 3,318 | $ 3,240 | $ 3,350 | $ 3,058 |
| Commercial | 3,092 | 3,077 | 3,094 | 3,271 | 3,077 |
| Industrial | 1,321 | 1,291 | 1,305 | 1,525 | 1,391 |
| Other | 89 | 86 | 88 | 94 | 94 |
| Total retail | 7,738 | 7,772 | 7,727 | 8,240 | 7,620 |
| Wholesale — non-affiliates | 163 | 175 | 215 | 335 | 281 |
| Wholesale — affiliates | 26 | 42 | 20 | 42 | 20 |
| Total revenues from sales of electricity | 7,927 | 7,989 | 7,962 | 8,617 | 7,921 |
| Other revenues | 383 | 394 | 364 | 371 | 353 |
| Total | $ 8,310 | $ 8,383 | $ 8,326 | $ 8,988 | $ 8,274 |
| **Kilowatt-Hour Sales (in millions):** | | | | | |
| Residential | 26,144 | 27,585 | 26,649 | 27,132 | 25,479 |
| Commercial | 32,155 | 32,932 | 32,719 | 32,426 | 31,984 |
| Industrial | 23,518 | 23,746 | 23,805 | 23,549 | 23,087 |
| Other | 584 | 610 | 632 | 633 | 630 |
| Total retail | 82,401 | 84,873 | 83,805 | 83,740 | 81,180 |
| Wholesale — non-affiliates | 3,277 | 3,415 | 3,501 | 4,323 | 3,029 |
| Wholesale — affiliates | 800 | 1,398 | 552 | 1,117 | 496 |
| Total | 86,478 | 89,686 | 87,858 | 89,180 | 84,705 |
| **Average Revenue Per Kilowatt-Hour (cents):** | | | | | |
| Residential | 12.38 | 12.03 | 12.16 | 12.35 | 12.00 |
| Commercial | 9.62 | 9.34 | 9.46 | 10.09 | 9.62 |
| Industrial | 5.62 | 5.44 | 5.48 | 6.48 | 6.03 |
| Total retail | 9.39 | 9.16 | 9.22 | 9.84 | 9.39 |
| Wholesale | 4.64 | 4.51 | 5.80 | 6.93 | 8.54 |
| Total sales | 9.17 | 8.91 | 9.06 | 9.66 | 9.35 |
| **Residential Average Annual Kilowatt-Hour Use Per Customer** | 12,028 | 12,864 | 12,582 | 12,969 | 12,293 |
| **Residential Average Annual Revenue Per Customer** | $ 1,489 | $ 1,557 | $ 1,529 | $ 1,605 | $ 1,475 |
| **Plant Nameplate Capacity Ratings (year-end) (megawatts)** | 15,274 | 15,274 | 15,455 | 17,593 | 17,586 |
| **Maximum Peak-Hour Demand (megawatts):** | | | | | |
| Winter | 13,894 | 14,527 | 15,735 | 16,308 | 12,767 |
| Summer | 16,002 | 16,244 | 16,104 | 15,777 | 15,228 |
| **Annual Load Factor (percent)** | 61.1 | 61.9 | 61.9 | 61.2 | 63.5 |
| **Plant Availability (percent):** | | | | | |
| Fossil-steam | 85.0 | 87.4 | 85.6 | 86.3 | 87.1 |
| Nuclear | 93.5 | 95.6 | 94.1 | 90.8 | 91.8 |
| **Source of Energy Supply (percent):** | | | | | |
| Oil and gas | 28.6 | 28.2 | 28.3 | 26.3 | 29.6 |
| Coal | 22.4 | 26.4 | 24.5 | 30.9 | 26.4 |
| Nuclear | 17.8 | 17.6 | 17.6 | 16.7 | 17.7 |
| Hydro | 1.0 | 1.1 | 1.6 | 1.3 | 2.0 |
| Other | 0.3 | — | — | — | — |
| Purchased power — | | | | | |
| From non-affiliates | 7.8 | 6.7 | 5.0 | 3.8 | 3.3 |
| From affiliates | 22.1 | 20.0 | 23.0 | 21.0 | 21.0 |
| Total | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |

# GULF POWER COMPANY

# FINANCIAL SECTION

**MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING**
**Gulf Power Company 2017 Annual Report**

The management of Gulf Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2017 .

/s/ S. W. Connally, Jr.
S. W. Connally, Jr.
Chairman, President, and Chief Executive Officer

/s/ Robin B. Boren
Robin B. Boren
Vice President, Chief Financial Officer, and Treasurer

February 20, 2018

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the stockholder and the Board of Directors of Gulf Power Company

**Opinion on the Financial Statements**

We have audited the accompanying balance sheets and statements of capitalization of Gulf Power Company (the Company) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2017 and 2016 , the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2017 , and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements (pages II-353 to II-391 ) present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016 , and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017 , in conformity with accounting principles generally accepted in the United States of America.

**Basis for Opinion**

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 20, 2018

We have served as the Company's auditor since 2002.

**DEFINITIONS**

| Term | Meaning |
|---|---|
| AFUDC | Allowance for funds used during construction |
| Alabama Power | Alabama Power Company |
| ARO | Asset retirement obligation |
| ASC | Accounting Standards Codification |
| ASU | Accounting Standards Update |
| CCR | Coal combustion residuals |
| Clean Air Act | Clean Air Act Amendments of 1990 |
| $CO_2$ | Carbon dioxide |
| EPA | U.S. Environmental Protection Agency |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| GAAP | U.S. generally accepted accounting principles |
| Georgia Power | Georgia Power Company |
| IRS | Internal Revenue Service |
| ITC | Investment tax credit |
| KWH | Kilowatt-hour |
| Mississippi Power | Mississippi Power Company |
| mmBtu | Million British thermal units |
| Moody's | Moody's Investors Service, Inc. |
| MW | Megawatt |
| $NO_X$ | Nitrogen oxide |
| OCI | Other comprehensive income |
| power pool | The operating arrangement whereby the integrated generating resources of the traditional electric operating companies and Southern Power (excluding subsidiaries) are subject to joint commitment and dispatch in order to serve their combined load obligations |
| PPA | Power purchase agreement |
| PSC | Public Service Commission |
| ROE | Return on equity |
| S&P | S&P Global Ratings, a division of S&P Global Inc. |
| scrubber | Flue gas desulfurization system |
| SCS | Southern Company Services, Inc. (the Southern Company system service company) |
| SEC | U.S. Securities and Exchange Commission |
| $SO_2$ | Sulfur dioxide |
| Southern Company | The Southern Company |
| Southern Company Gas | Southern Company Gas and its subsidiaries |
| Southern Company system | Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), Southern Electric Generating Company, Southern Nuclear, SCS, Southern Linc, PowerSecure, Inc. (as of May 9, 2016), and other subsidiaries |
| Southern Linc | Southern Communications Services, Inc. |
| Southern Nuclear | Southern Nuclear Operating Company, Inc. |
| Southern Power | Southern Power Company and its subsidiaries |
| Tax Reform Legislation | The Tax Cuts and Jobs Act, which was signed into law on December 22, 2017 and became effective on January 1, 2018 |
| traditional electric operating companies | Alabama Power, Georgia Power, Gulf Power Company, and Mississippi Power |

**MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS**
**Gulf Power Company 2017 Annual Report**

**OVERVIEW**

**Business Activities**

Gulf Power Company (the Company) operates as a vertically integrated utility providing electric service to retail customers within its traditional service territory located in northwest Florida and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of providing electric service. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales and customers, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, stringent environmental standards, reliability, restoration following major storms, fuel, and capital expenditures. The Company has various regulatory mechanisms that operate to address cost recovery. Effectively operating pursuant to these regulatory mechanisms and appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

On April 4, 2017, the Florida PSC approved a settlement agreement (2017 Rate Case Settlement Agreement) among the Company and three intervenors with respect to the Company's request in 2016 to increase retail base rates. Among the terms of the 2017 Rate Case Settlement Agreement, the Company increased rates effective with the first billing cycle in July 2017 to provide an annual overall net customer impact of approximately $54.3 million . The net customer impact consisted of a $62.0 million increase in annual base revenues, less an annual purchased power capacity cost recovery clause credit for certain wholesale revenues of approximately $8 million through December 2019. In addition, the Company continued its authorized retail ROE midpoint ( 10.25% ) and range ( 9.25% to 11.25% ), is deemed to have a maximum equity ratio of 52.5% for all retail regulatory purposes, and implemented new dismantlement accruals effective July 1, 2017. The Company also began amortizing the regulatory asset associated with the investment balances remaining after the retirement of Plant Smith Units 1 and 2 ( 357 MWs) over 15 years effective January 1, 2018 and implemented new depreciation rates effective January 1, 2018. The 2017 Rate Case Settlement Agreement also resulted in a $32.5 million write-down of the Company's ownership of Plant Scherer Unit 3 ( 205 MWs), which was recorded in the first quarter 2017. The remaining issues related to the inclusion of the Company's investment in Plant Scherer Unit 3 in retail rates have been resolved as a result of the 2017 Rate Case Settlement Agreement, including recoverability of certain costs associated with the ongoing ownership and operation of the unit through the environmental cost recovery clause.

The 2017 Rate Case Settlement Agreement set forth a process for addressing the revenue requirement effects of the Tax Reform Legislation through a prospective change to the Company's base rates. Under the terms of the 2017 Rate Case Settlement Agreement, by March 1, 2018, the Company must identify the revenue requirements impacts and defer them to a regulatory asset or regulatory liability to be considered for prospective application in a change to base rates in a limited scope proceeding before the Florida PSC. In lieu of this approach, on February 14, 2018, the parties to the 2017 Rate Case Settlement Agreement filed a new stipulation and settlement agreement (2018 Tax Reform Settlement Agreement) with the Florida PSC. If approved, the 2018 Tax Reform Settlement Agreement will result in annual reductions of $18.2 million to the Company's base rates and $15.6 million to the Company's environmental cost recovery rates effective beginning the first calendar month following approval.

The 2018 Tax Reform Settlement Agreement also provides for a one-time refund of $69.4 million for the retail portion of unprotected (not subject to normalization) deferred tax liabilities through the Company's fuel cost recovery rate over the remainder of 2018. In addition, a limited scope proceeding to address the flow back of protected deferred tax liabilities will be initiated by May 1, 2018 and the Company will record a regulatory liability for the related 2018 amounts eligible to be returned to customers consistent with IRS normalization principles. Unless otherwise agreed to by the parties to the 2018 Tax Reform Settlement Agreement, amounts recorded in this regulatory liability will be refunded to retail customers in 2019 through the Company's fuel cost recovery rate.

If the 2018 Tax Reform Settlement Agreement is approved, the 2017 Rate Case Settlement Agreement will be amended to increase the Company's maximum equity ratio from 52.5% to 53.5% for regulatory purposes.

The ultimate outcome of these matters cannot be determined at this time.

On October 25, 2017, the Florida PSC approved the Company's 2018 annual cost recovery clause factors to provide for a net annual revenue increase of $63 million. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Cost Recovery Clauses" herein for additional information.

The Company continues to focus on several key performance indicators including, but not limited to, customer satisfaction, plant availability, system reliability, and net income after dividends on preference stock. The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys to evaluate the Company's results and generally targets the top quartile of these surveys in measuring performance.

See RESULTS OF OPERATIONS herein for information on the Company's financial performance.

**Earnings**

The Company's 2017 net income after dividends on preference stock was $135 million , representing a $4 million , or 3.1% , increase over the previous year. The increase was primarily due to higher retail base revenues and lower depreciation, partially offset by a write-down of $32.5 million ($20 million after tax) of the Company's ownership of Plant Scherer Unit 3 resulting from the 2017 Rate Case Settlement Agreement and by higher operations and maintenance expenses as compared to the corresponding period in 2016 .

In 2016 , the net income after dividends on preference stock was $131 million , representing a $17 million , or 11.5% , decrease over the previous year. The decrease was primarily due to lower wholesale revenues and higher depreciation, partially offset by higher retail revenues and lower operations and maintenance expenses as compared to the corresponding period in 2015.

**RESULTS OF OPERATIONS**

A condensed statement of income follows:

| | Amount | Increase (Decrease) from Prior Year | |
|---|---|---|---|
| | **2017** | **2017** | 2016 |
| | | *(in millions)* | |
| Operating revenues | **$ 1,516** | **$ 31** | $ 2 |
| Fuel | **427** | **(5)** | (13) |
| Purchased power | **155** | **13** | 7 |
| Other operations and maintenance | **359** | **23** | (18) |
| Depreciation and amortization | **137** | **(35)** | 31 |
| Taxes other than income taxes | **116** | **(4)** | 2 |
| Loss on Plant Scherer Unit 3 | **33** | **33** | — |
| Total operating expenses | **1,227** | **25** | 9 |
| Operating income | **289** | **6** | (7) |
| Total other income and (expense) | **(60)** | **(8)** | (11) |
| Income taxes | **90** | **(1)** | (1) |
| Net income | **139** | **(1)** | (17) |
| Dividends on preference stock | **4** | **(5)** | — |
| Net income after dividends on preference stock | **$ 135** | **$ 4** | $ (17) |

***Operating Revenues***

Operating revenues for 2017 were $1.52 billion , reflecting an increase of $31 million from 2016 . Details of operating revenues were as follows:

| | Amount | |
|---|---|---|
| | **2017** | 2016 |
| | *(in millions)* | |
| Retail — prior year | **$ 1,281** | $ 1,249 |
| Estimated change resulting from – | | |
| Rates and pricing | **40** | 30 |
| Sales growth | **2** | — |
| Weather | **(11)** | 1 |
| Fuel and other cost recovery | **(31)** | 1 |
| Retail — current year | **1,281** | 1,281 |
| Wholesale revenues – | | |
| Non-affiliates | **57** | 61 |
| Affiliates | **108** | 75 |
| Total wholesale revenues | **165** | 136 |
| Other operating revenues | **70** | 68 |
| Total operating revenues | **$ 1,516** | $ 1,485 |
| Percent change | **2.1%** | N/M |

N/M - Not meaningful

In 2017 , retail revenues remained flat when compared to 2016 primarily due to an increase in retail base revenues effective with the first billing cycle in July 2017, offset by decreases in fuel and purchased power capacity clause revenues and the impact of milder weather. In 2016 , retail revenues increase d $32 million , or 2.6% , when compared to 2015 primarily as a result of an increase in the Company's environmental cost recovery clause revenues, partially offset by a decrease in the energy conservation clause revenues. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth and weather.

In 2017 , revenues associated with changes in rates and pricing increased primarily due to an increase in retail base rates effective with the first billing cycle in July 2017. In 2016 , revenues associated with changes in rates and pricing increased primarily due to an increase in the environmental cost recovery clause as a result of additional rate base investment related to environmental compliance equipment placed in service at the end of 2015 as well as portions of the Company's ownership in Plant Scherer Unit 3 that were rededicated to retail service in 2016. Annually, the Company petitions the Florida PSC for recovery of projected environmental and energy conservation costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions include related expenses and a return on average net investment.

Fuel and other cost recovery provisions include fuel expenses, the energy component of purchased power costs, purchased power capacity costs, the difference between projected and actual costs and revenues related to energy conservation and environmental compliance, and a credit for certain wholesale revenues as a result of the 2017 Rate Case Settlement Agreement. Annually, the Company petitions the Florida PSC for recovery of projected fuel and purchased power costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions generally equal the related expenses and have no material effect on earnings.

See Note 1 to the financial statements under "Revenues" and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information regarding the Company's retail base rate cases, cost recovery clauses, and related rate changes.

**MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)**
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Wholesale revenues from power sales to non-affiliated utilities were as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | (in millions) | |
| Capacity and other | $ 25 | $ 30 | $ 67 |
| Energy | 32 | 31 | 40 |
| Total non-affiliated | $ 57 | $ 61 | $ 107 |

Wholesale revenues from sales to non-affiliates consist of long-term sales agreements to other utilities in Florida and Georgia and short-term opportunity sales. Capacity revenues from long-term sales agreements represent the greatest contribution to net income. The energy is generally sold at variable cost. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost of energy. Wholesale energy revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation.

In 2017 , wholesale revenues from sales to non-affiliates decrease d $4 million , or 6.6% , as compared to the prior year primarily due to a 16.0% decrease in capacity revenues resulting from the expiration of a Plant Scherer Unit 3 long-term sales agreement in 2016. In 2016 , wholesale revenues from sales to non-affiliates decrease d $46 million , or 43.0% , as compared to the prior year primarily due to a 55.3% decrease in capacity revenues resulting from the expiration of Plant Scherer Unit 3 long-term sales agreements in December 2015 and May 2016.

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. These transactions do not have a significant impact on earnings since the revenue related to these energy sales generally offsets the cost of energy sold. In 2017 , wholesale revenues from sales to affiliates increase d $33 million , or 44.0% , as compared to the prior year primarily due to a 39.6% increase in KWH sales to affiliates due to the dispatch of the Company's lower cost generation resources to serve system territorial load. In 2016 , wholesale revenues from sales to affiliates increase d $17 million , or 29.3% , as compared to the prior year primarily due to a 46.1% increase in KWH sales to affiliates due to lower planned unit outages for the Company's generation resources and a 7.9% increase in the price of energy sold to affiliates due to more sales during peak load hours.

*Energy Sales*

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2017 and the percent change from the prior year were as follows:

| | Total KWHs | Total KWH Percent Change | | Weather-Adjusted Percent Change | |
|---|---|---|---|---|---|
| | 2017 | 2017 | 2016 | 2017 | 2016 |
| | (in millions) | | | | |
| Residential | 5,229 | (2.4)% | (0.1)% | 1.3 % | (0.2)% |
| Commercial | 3,814 | (1.4) | (0.7) | — | (1.5) |
| Industrial | 1,740 | (5.0) | 1.8 | (5.0) | 1.8 |
| Other | 26 | 4.5 | (0.8) | 4.5 | (0.8) |
| Total retail | 10,809 | (2.5) | — | (0.2)% | (0.3)% |
| Wholesale | | | | | |
| Non-affiliates | 749 | (0.1) | (27.8) | | |
| Affiliates | 3,887 | 39.6 | 46.1 | | |
| Total wholesale | 4,636 | 31.2 | 20.0 | | |
| Total energy sales | 15,445 | 5.7 % | 4.2 % | | |

Changes in retail energy sales are generally the result of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales decreased 2.5% in 2017 compared to the prior year primarily due to milder weather in the first half of the year, partially offset by customer growth. Weather-adjusted residential KWH sales increased primarily due to customer growth. Weather-adjusted commercial KWH sales remained flat as a result of lower customer usage primarily resulting from efficiency improvements in appliances and lighting, offset by customer growth. Industrial KWH sales decreased in 2017 compared to 2016 primarily due to changes in customers' operations and energy efficiency improvements.

Residential and commercial KWH sales decreased in 2016 compared to 2015 due to declining use per customer primarily resulting from energy efficiency improvements, partially offset by customer growth and warmer weather during the third quarter. Industrial KWH sales increased in 2016 compared to 2015 primarily due to decreased customer co-generation, partially offset by changes in customers' operations.

See "Operating Revenues" above for a discussion of significant changes in wholesale sales to non-affiliates and affiliated companies.

***Fuel and Purchased Power Expenses***

Fuel costs constitute one of the largest expenses for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

Details of the Company's generation and purchased power were as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| Total generation *(in millions of KWHs)* | **9,310** | 8,259 | 8,629 |
| Total purchased power *(in millions of KWHs)* | **5,991** | 6,973 | 5,976 |
| Sources of generation *(percent)* – | | | |
| Coal | **54** | 57 | 57 |
| Gas | **46** | 43 | 43 |
| Cost of fuel, generated *(in cents per net KWH)* – | | | |
| Coal | **3.14** | 3.68 | 3.88 |
| Gas | **3.55** | 4.17 | 4.22 |
| Average cost of fuel, generated *(in cents per net KWH)* | **3.32** | 3.89 | 4.03 |
| Average cost of purchased power *(in cents per net KWH)* (*) | **4.55** | 3.63 | 3.89 |

(*) Average cost of purchased power includes fuel purchased by the Company for tolling agreements where power is generated by the provider.

In 2017 , total fuel and purchased power expenses were $582 million , an increase of $8 million , or 1.4% , from the prior year costs. The increase was primarily the result of a $6 million net increase due to a higher volume of KWHs generated and purchased and a $2 million net increase due to a higher average cost of fuel and purchased power.

In 2016 , total fuel and purchased power expenses were $574 million , a decrease of $6 million , or 1.0% , from the prior year costs. The decrease was primarily the result of a $30 million decrease due to a lower average cost of fuel and purchased power, largely offset by a $24 million increase due to a higher volume of KWHs generated and purchased.

Fuel and purchased power transactions do not have a significant impact on earnings since energy and capacity expenses are generally offset by energy and capacity revenues through the Company's fuel and purchased power capacity cost recovery clauses and long-term wholesale contracts. See Note 3 to the financial statements under "Retail Regulatory Matters – Cost Recovery Clauses – Retail Fuel Cost Recovery" and " – Purchased Power Capacity Recovery" for additional information.

*Fuel*

Fuel expense was $427 million in 2017 , a decrease of $5 million , or 1.2% , from the prior year costs. The decrease was primarily due to a 14.7% decrease in the average cost of fuel per KWH generated due to lower coal and natural gas prices, partially offset by a 12.7% higher volume of KWHs generated due to the dispatch of the Company's lower cost generation resources to serve system territorial load. In 2016 , fuel expense was $432 million , a decrease of $13 million , or 2.9% , from the prior year costs. The decrease was primarily due to a 3.5% decrease in the average cost of fuel per KWH generated due to lower coal and natural gas prices and a 4.3% lower volume of KWHs generated due to an increase in KWHs purchased from lower-cost gas-fired PPA resources.

*Purchased Power*

Purchased power expense was $155 million in 2017 , an increase of $13 million , or 9.2% , from the prior year. The increase was primarily due to a 25.3% increase in the average cost per KWH purchased, partially offset by a 14.1% decrease in the volume of KWHs purchased. In 2016 , purchased power expense was $142 million , an increase of $7 million , or 5.2% , from the prior year. The increase was primarily due to a 16.7% increase in the volume of KWHs purchased, partially offset by a 6.7% decrease in the average cost per KWH purchased resulting from lower energy costs from gas-fired resources.

Energy purchases from non-affiliates and affiliates will vary depending on the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation. Affiliate purchases are made in accordance with the IIC or other contractual agreements, as approved by the FERC.

***Other Operations and Maintenance Expenses***

In 2017 , other operations and maintenance expenses increase d $23 million , or 6.8% , compared to the prior year primarily due to increases of $7 million in environmental compliance expenses, $6 million in rate case expense amortization related to the 2017 Rate Case Settlement Agreement, $6 million in routine and planned maintenance at generation facilities, and $3 million in energy services expenses. In 2016 , other operations and maintenance expenses decrease d $18 million , or 5.1% , compared to the prior year primarily due to decreases of $7 million in marketing incentive programs and $6 million in routine and planned maintenance expenses at generation facilities. Also contributing to the decrease was $4 million in rate case expense amortization recorded in 2015 and a $3 million reduction in employee compensation and benefits expenses including pension costs.

Expenses from energy services and marketing incentive programs did not have a significant impact on earnings since they were generally offset by associated revenues. Rate case expenses were amortized as authorized in the 2017 Rate Case Settlement Agreement and a settlement agreement approved by the Florida PSC in 2013 (2013 Rate Case Settlement Agreement). See Note 3 to the financial statements under "Retail Regulatory Matters – Base Rate Cases" and " – Cost Recovery Clauses" and Note 2 to the financial statements for additional information related to rate case expenses and environmental compliance costs and pension costs, respectively.

***Depreciation and Amortization***

Depreciation and amortization decrease d $35 million , or 20.3% , in 2017 compared to the prior year. The decrease was primarily due to the reduction in depreciation of $34.0 million recorded in 2017, as authorized in the 2013 Rate Case Settlement Agreement. In 2016 , depreciation and amortization increase d $31 million , or 22.0% , compared to the prior year. The increase was primarily due to a reduction in depreciation of $20.1 million recorded in 2015, as authorized in the 2013 Rate Case Settlement Agreement, and an increase of $9 million primarily attributable to property additions to utility plant. See Note 3 to the financial statements under "Retail Regulatory Matters – Retail Base Rate Cases" for additional information.

***Total Other Income and (Expense)***

In 2017 , total other income and (expense) decrease d $8 million , or 15.4% , compared to the prior year primarily due to a $5 million increase in donations and a $3 million increase in interest expense, net of amounts capitalized. The increase in interest expense was primarily due to deferred returns on transmission projects in 2016, which reduced interest expense and were recorded as a regulatory asset, as authorized in the 2013 Rate Case Settlement Agreement. In 2016 , total other income and (expense) decrease d $11 million , or 26.8% , primarily due to a decrease of $13 million in AFUDC equity related to environmental control projects at generating facilities and transmission projects placed in service in 2015, partially offset by a $2 million decrease in interest expense, net of amounts capitalized, primarily due to the redemption of debt. See Note 1 to the financial statements under "Allowance for Funds Used During Construction" for additional information.

***Dividends on Preference Stock***

Dividends on preference stock decrease d $5 million , or 55.6% , in 2017 compared to the prior year due to the redemption of all preference stock in June 2017. See FINANCIAL CONDITION AND LIQUIDITY – "Financing Activities" herein for additional information.

**Effects of Inflation**

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

## FUTURE EARNINGS POTENTIAL

### General

The Company operates as a vertically integrated utility providing electric service to retail customers within its traditional service territory located in northwest Florida and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Florida PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of providing electric service. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs and limited projected demand growth over the next several years. Future earnings will be driven primarily by customer growth. Earnings will also depend upon maintaining and growing sales, considering, among other things, the adoption and/or penetration rates of increasingly energy-efficient technologies due to changes in the minimum allowable equipment efficiencies along with the continuation of changes in customer behavior, both of which could contribute to a net reduction in customer usage. Earnings are subject to a variety of other factors. These factors include weather, competition, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territory. Demand for electricity is primarily driven by the pace of economic growth that may be affected by changes in regional and global economic conditions, which may impact future earnings.

On December 22, 2017, the Tax Reform Legislation was signed into law and became effective on January 1, 2018, which among other things, reduces the federal corporate income tax rate to 21% and changes rates of depreciation and the business interest deduction. See " Income Tax Matters – Federal Tax Reform Legislation " and FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein and Notes 3 and 5 to the financial statements for additional information.

### Environmental Matters

The Company's operations are regulated by state and federal environmental agencies through a variety of laws and regulations governing air, water, land, and protection of other natural resources. The Company maintains a comprehensive environmental compliance strategy to assess upcoming requirements and compliance costs associated with these environmental laws and regulations. The costs, including capital expenditures and operations and maintenance costs, required to comply with environmental laws and regulations may impact future unit retirement and replacement decisions, results of operations, cash flows, and financial condition. Compliance costs may result from the installation of additional environmental controls, closure and monitoring of CCR facilities, unit retirements, and adding or changing fuel sources for certain existing units, as well as related upgrades to the transmission system. A major portion of these compliance costs are expected to be recovered through existing ratemaking provisions. The ultimate impact of the environmental laws and regulations discussed below will depend on various factors, such as state adoption and implementation of requirements, the availability and cost of any deployed control technology, and the outcome of pending and/or future legal challenges.

New or revised environmental laws and regulations could affect many areas of the Company's operations. The impact of any such changes cannot be determined at this time. Environmental compliance costs could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis or through long-term wholesale agreements . The State of Florida has statutory provisions that allow a utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. The Company's current long-term wholesale agreements contain provisions that permit charging the customer with costs incurred as a result of changes in environmental laws and regulations . Further, increased costs that are recovered through regulated rates could contribute to reduced demand for electricity , which could negatively affect results of operations, cash flows, and financial condition. Additionally, many commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity . See "Other Matters" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Cost Recovery Clauses – Environmental Cost Recovery" for additional information, including a discussion on the State of Florida's statutory provisions on environmental cost recovery.

Through 2017 , the Company has invested approximately $2.0 billion in environmental capital retrofit projects to comply with environmental requirements, with annual totals of approximately $30 million, $28 million, and $116 million for 2017 , 2016 , and 2015 , respectively. Although the timing, requirements, and estimated costs could change as environmental laws and regulations are adopted or modified, as compliance plans are revised or updated, and as legal challenges to rules are initiated or completed, the Company's current compliance strategy estimates capital expenditures of $279 million from 2018 through 2022 , with annual totals of approximately $65 million, $57 million, $83 million, $58 million, and $16 million for 2018 , 2019 , 2020 , 2021 , and 2022 , respectively. These estimates do not include any potential compliance costs associated with the regulation of $CO_2$ emissions from fossil fuel-fired electric generating units. See "Global Climate Issues" herein for additional information. The Company also anticipates expenditures associated with ash pond closure and ground water monitoring under the Disposal of Coal Combustion Residuals from Electric Utilities rule (CCR Rule), which are reflected in the Company's ARO liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

***Environmental Laws and Regulations***

*Air Quality*

The EPA has set National Ambient Air Quality Standards (NAAQS) for six air pollutants (carbon monoxide, lead, nitrogen dioxide, ozone, particulate matter, and $SO_2$ ), which it reviews and revises periodically. Revisions to these standards can require additional emission controls, improvements in control efficiency, or fuel changes which can result in increased compliance and operational costs. NAAQS requirements can also adversely affect the siting of new facilities. In 2015, the EPA published a more stringent eight-hour ozone NAAQS. The EPA plans to complete designations for this rule by no later than April 30, 2018 . No areas within the Company's service territory have been or are anticipated to be designated nonattainment under the 2015 ozone NAAQS. In 2010, the EPA revised the NAAQS for $SO_2$ , establishing a new one-hour standard, and is completing designations in multiple phases. The EPA has issued several rounds of area designations and no areas in the vicinity of Company -owned $SO_2$ sources have been designated nonattainment under the 2010 one-hour $SO_2$ NAAQS. However, final eight-hour ozone and $SO_2$ one-hour designations for certain areas are still pending and, if other areas are designated as nonattainment in the future, increased compliance costs could result.

In 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) and its $NO_X$ annual, $NO_X$ seasonal, and $SO_2$ annual programs. CSAPR is an emissions trading program that addresses the impacts of the interstate transport of $SO_2$ and $NO_X$ emissions from fossil fuel-fired power plants located in upwind states in the eastern half of the U.S. on air quality in downwind states. The Company has fossil fuel-fired generation subject to these requirements. In October 2016, the EPA published a final rule that revised the CSAPR seasonal $NO_X$ program, which completely removed Florida from all CSAPR programs, left the Georgia seasonal $NO_X$ budget unchanged, and established more stringent $NO_X$ emissions budgets in Mississippi. The outcome of ongoing CSAPR litigation could have an impact on the State of Mississippi's allowance allocations under the CSAPR seasonal $NO_X$ program. Increases in either future fossil fuel-fired generation or the cost of CSAPR allowances could have a negative financial impact on results of operations for the Company.

The EPA finalized regional haze regulations in 2005 and 2017. These regulations require states, tribal governments, and various federal agencies to develop and implement plans to reduce pollutants that impair visibility and demonstrate reasonable progress toward the goal of restoring natural visibility conditions in certain areas, including national parks and wilderness areas. States must submit a revised state implementation plan (SIP) to the EPA by July 31, 2021, demonstrating reasonable progress towards achieving visibility improvement goals. State implementation of reasonable progress could require further reductions in $SO_2$ or $NO_X$ emissions, which could result in increased compliance costs.

In 2015, the EPA published a final rule requiring certain states (including Florida, Georgia, and Mississippi ) to revise or remove the provisions of their SIPs regulating excess emissions at industrial facilities, including electric generating facilities, during periods of startup, shut-down, or malfunction (SSM). The state excess emission rules provide necessary operational flexibility to affected units during periods of SSM and, if removed, could affect unit availability and result in increased operations and maintenance costs for the Company . The EPA has not yet responded to the SIP revisions proposed by states where the Company's generating units are located.

*Water Quality*

In 2014, the EPA finalized requirements under Section 316(b) of the Clean Water Act (CWA) to regulate cooling water intake structures at existing power plants and manufacturing facilities in order to minimize their effects on fish and other aquatic life. The regulation requires plant-specific studies to determine applicable measures to protect organisms that either get caught on the intake screens (impingement) or are drawn into the cooling system (entrainment). The ultimate impact of this rule will depend on the outcome of these plant-specific studies and any additional protective measures required to be incorporated into each plant's National Pollutant Discharge Elimination System (NPDES) permit based on site-specific factors.

In 2015, the EPA finalized the steam electric effluent limitations guidelines (ELG) rule that set national standards for wastewater discharges from steam electric generating units. The rule prohibits effluent discharges of certain wastestreams and imposes stringent arsenic, mercury, selenium, and nitrate/nitrite limits on scrubber wastewater discharges. The revised technology-based limits and compliance dates may require extensive modifications to existing ash and wastewater management systems or the installation and operation of new ash and wastewater management systems. Compliance with the ELG rule is expected to require capital expenditures and increased operational costs primarily affecting the Company's coal-fired electric generation. Compliance applicability dates range from November 1, 2018 to December 31, 2023 with state environmental agencies incorporating specific applicability dates in the NPDES permitting process based on information provided for each waste stream. The EPA has committed to a new rulemaking that could potentially revise the limitations and applicability dates of the ELG rule. The EPA expects to finalize this rulemaking in 2020.

In 2015, the EPA and the U.S. Army Corps of Engineers (Corps) jointly published a final rule that revised the regulatory definition of waters of the United States (WOTUS) for all CWA programs. The rule significantly expanded the scope of federal jurisdiction over waterbodies (such as rivers, streams, and canals), which could impact new generation projects and permitting and reporting requirements associated with the installation, expansion, and maintenance of transmission and distribution projects. On July 27, 2017, the EPA and the Corps proposed to rescind the 2015 WOTUS rule. The WOTUS rule has been stayed by the U.S. Court of Appeals for the Sixth Circuit since late 2015, but on January 22, 2018, the U.S. Supreme Court determined that federal district courts have jurisdiction over the pending challenges to the rule. On February 6, 2018, the EPA and the Corps published a final rule delaying implementation of the 2015 WOTUS rule to 2020.

In addition, numeric nutrient water quality standards promulgated by the State of Florida to limit the amount of nitrogen and phosphorous allowed in state waters are in effect for the State's streams and estuaries. The impact of these standards will depend on further regulatory action in connection with their site-specific implementation through the State of Florida's NPDES permitting program and Total Maximum Daily Load restoration program and cannot be determined at this time.

*Coal Combustion Residuals*

In 2015, the EPA finalized non-hazardous solid waste regulations for the disposal of CCR, including coal ash and gypsum, in landfills and surface impoundments (CCR units) at active generating power plants. The CCR Rule requires CCR units to be evaluated against a set of performance criteria and potentially closed if minimum criteria are not met. Closure of existing CCR units could require installation of equipment and infrastructure to manage CCR in accordance with the rule. The EPA has announced plans to reconsider certain portions of the CCR Rule by no later than December 2019, which could result in changes to deadlines and corrective action requirements.

The EPA's reconsideration of the CCR Rule is due in part to a legislative development that impacts the potential oversight role of state agencies. Under the Water Infrastructure Improvements for the Nation Act, which became law in 2016, states are allowed to establish permit programs for implementing the CCR Rule.

Based on cost estimates for closure and monitoring of ash ponds pursuant to the CCR Rule, and the closure of an ash pond at Plant Scholz, the Company recorded AROs for each CCR unit in 2015. As further analysis is performed and closure details are developed, the Company will continue to periodically update these cost estimates as necessary. The estimated costs associated with closure of the ash ponds at Plant Scholz and Plant Smith for 2018 have been approved for recovery through the environmental cost recovery clause. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information regarding the Company's AROs as of December 31, 2017 .

*Environmental Remediation*

The Company must comply with environmental laws and regulations governing the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up affected sites. The Company conducts studies to determine the extent of any required cleanup and has recognized the estimated costs to clean up known affected sites in its financial statements. Included in this amount are costs associated with remediation of the Company's substation sites. These projects have been approved by the Florida PSC for recovery through the environmental cost recovery clause; therefore, these liabilities have no impact to the Company's net income. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

### *Global Climate Issues*

In 2015, the EPA published final rules limiting $CO_2$ emissions from new, modified, and reconstructed fossil fuel-fired electric generating units and guidelines for states to develop plans to meet EPA-mandated $CO_2$ emission performance standards for existing units (known as the Clean Power Plan or CPP). In February 2016, the U.S. Supreme Court granted a stay of the CPP, which will remain in effect through the resolution of litigation in the U.S. Court of Appeals for the District of Columbia challenging the legality of the CPP and any review by the U.S. Supreme Court. On March 28, 2017, the U.S. President signed an executive order directing agencies to review actions that potentially burden the development or use of domestically produced energy resources, including review of the CPP and other $CO_2$ emissions rules. On October 10, 2017, the EPA published a proposed rule to repeal the CPP and, on December 28, 2017, published an advanced notice of proposed rulemaking regarding a CPP replacement rule.

In 2015, parties to the United Nations Framework Convention on Climate Change, including the United States, adopted the Paris Agreement, which established a non-binding universal framework for addressing greenhouse gas (GHG) emissions based on nationally determined contributions. On June 1, 2017, the U.S. President announced that the United States would withdraw from the Paris Agreement and begin renegotiating its terms. The ultimate impact of this agreement or any renegotiated agreement depends on its implementation by participating countries.

The EPA's GHG reporting rule requires annual reporting of GHG emissions expressed in terms of metric tons of $CO_2$ equivalent emissions for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2016 GHG emissions were approximately 8 million metric tons of $CO_2$ equivalent. The preliminary estimate of the Company's 2017 GHG emissions on the same basis is approximately 7 million metric tons of $CO_2$ equivalent.

## FERC Matters

The Company has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies (including the Company) and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In 2015, the FERC issued an order finding that the traditional electric operating companies' (including the Company's) and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional electric operating companies (including the Company) and Southern Power filed a request for rehearing and filed their response with the FERC in 2015.

In December 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. On May 17, 2017, the FERC accepted the traditional electric operating companies' (including the Company's) and Southern Power's compliance filing accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

On October 25, 2017, the FERC issued an order in response to the traditional electric operating companies' (including the Company's) and Southern Power's June 29, 2017 triennial updated market power analysis. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show cause within 60 days why market-based rate authority should not be revoked in certain areas adjacent to the area presently under mitigation in accordance with the February 2, 2017 order or to provide a mitigation plan to further address market power concerns. On November 10, 2017, the traditional electric operating companies (including the Company) and Southern Power responded to the FERC and proposed to resolve matters by applying the alternative mitigation authorized by the February 2, 2017 order to the adjacent areas made the subject of the October 25, 2017 order.

The ultimate outcome of these matters cannot be determined at this time.

**Retail Regulatory Matters**

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates. See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

***Retail Base Rate Cases***

In the 2013 Rate Case Settlement Agreement, the Florida PSC authorized the Company to reduce depreciation and record a regulatory asset up to $62.5 million from January 2014 through June 2017. In any given month, such depreciation reduction was not to exceed the amount necessary for the retail ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized retail ROE range then in effect. For 2014 and 2015, the Company recognized reductions in depreciation of $8.4 million and $20.1 million , respectively. No net reduction in depreciation was recorded in 2016. In 2017, the Company recognized the remaining $34.0 million reduction in depreciation.

On April 4, 2017, the Florida PSC approved the 2017 Rate Case Settlement Agreement among the Company and three intervenors with respect to the Company's request in 2016 to increase retail base rates. Among the terms of the 2017 Rate Case Settlement Agreement, the Company increased rates effective with the first billing cycle in July 2017 to provide an annual overall net customer impact of approximately $54.3 million . The net customer impact consisted of a $62.0 million increase in annual base revenues, less an annual purchased power capacity cost recovery clause credit for certain wholesale revenues of approximately $8 million through December 2019. In addition, the Company continued its authorized retail ROE midpoint ( 10.25% ) and range ( 9.25% to 11.25% ), is deemed to have a maximum equity ratio of 52.5% for all retail regulatory purposes, and implemented new dismantlement accruals effective July 1, 2017. The Company also began amortizing the regulatory asset associated with the investment balances remaining after the retirement of Plant Smith Units 1 and 2 over 15 years effective January 1, 2018 and implemented new depreciation rates effective January 1, 2018. The 2017 Rate Case Settlement Agreement also resulted in a $32.5 million write-down of the Company's ownership of Plant Scherer Unit 3, which was recorded in the first quarter 2017. The remaining issues related to the inclusion of the Company's investment in Plant Scherer Unit 3 in retail rates have been resolved as a result of the 2017 Rate Case Settlement Agreement, including recoverability of certain costs associated with the ongoing ownership and operation of the unit through the environmental cost recovery clause.

The 2017 Rate Case Settlement Agreement set forth a process for addressing the revenue requirement effects of the Tax Reform Legislation through a prospective change to the Company's base rates. Under the terms of the 2017 Rate Case Settlement Agreement, by March 1, 2018, the Company must identify the revenue requirements impacts and defer them to a regulatory asset or regulatory liability to be considered for prospective application in a change to base rates in a limited scope proceeding before the Florida PSC. In lieu of this approach, on February 14, 2018, the parties to the 2017 Rate Case Settlement Agreement filed the 2018 Tax Reform Settlement Agreement with the Florida PSC. If approved, the 2018 Tax Reform Settlement Agreement will result in annual reductions of $18.2 million to the Company's base rates and $15.6 million to the Company's environmental cost recovery rates effective beginning the first calendar month following approval.

The 2018 Tax Reform Settlement Agreement also provides for a one-time refund of $69.4 million for the retail portion of unprotected (not subject to normalization) deferred tax liabilities through the Company's fuel cost recovery rate over the remainder of 2018. In addition, a limited scope proceeding to address the flow back of protected deferred tax liabilities will be initiated by May 1, 2018 and the Company will record a regulatory liability for the related 2018 amounts eligible to be returned to customers consistent with IRS normalization principles. Unless otherwise agreed to by the parties to the 2018 Tax Reform Settlement Agreement, amounts recorded in this regulatory liability will be refunded to retail customers in 2019 through the Company's fuel cost recovery rate.

If the 2018 Tax Reform Settlement Agreement is approved, the 2017 Rate Case Settlement Agreement will be amended to increase the Company's maximum equity ratio from 52.5% to 53.5% for regulatory purposes.

The ultimate outcome of these matters cannot be determined at this time.

### *Cost Recovery Clauses*

As discussed previously, the 2017 Rate Case Settlement Agreement resolved the remaining issues related to the Company's inclusion of certain costs associated with the ongoing ownership and operation of Plant Scherer Unit 3 in the environmental cost recovery clause and no adjustment to the environmental cost recovery clause rate approved by the Florida PSC in November 2016 was made.

On October 25, 2017, the Florida PSC approved the Company's annual clause rate request for its fuel, purchased power capacity, environmental, and energy conservation cost recovery factors for 2018. The net effect of the approved changes is a $63 million increase in annual revenues effective in January 2018, the majority of which will be offset by related expense increases.

Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment. See Note 1 to the financial statements under "Revenues" for additional information.

## Income Tax Matters

### *Federal Tax Reform Legislation*

On December 22, 2017, the Tax Reform Legislation was signed into law and became effective on January 1, 2018. The Tax Reform Legislation, among other things, reduces the federal corporate income tax rate to 21%, retains normalization provisions for public utility property and existing renewable energy incentives, and repeals the corporate alternative minimum tax.

Regulated utility businesses can continue deducting all business interest expense and are not eligible for bonus depreciation on capital assets acquired and placed in service after September 27, 2017. Projects with binding contracts before September 28, 2017 and placed in service after September 27, 2017 remain eligible for bonus depreciation under the Protecting Americans from Tax Hikes (PATH) Act.

In addition, under the Tax Reform Legislation, net operating losses (NOLs) generated after December 31, 2017 can no longer be carried back to previous tax years but can be carried forward indefinitely, with utilization limited to 80% of taxable income in the subsequent tax year.

For the year ended December 31, 2017, implementation of the Tax Reform Legislation resulted in a $25 million decrease in regulatory assets and a $456 million increase in regulatory liabilities, primarily due to the impact of the reduction of the corporate income tax rate on deferred tax assets and liabilities.

The Tax Reform Legislation is subject to further interpretation and guidance from the IRS, as well as each respective state's adoption. In addition, the regulatory treatment of certain impacts of the Tax Reform Legislation is subject to the discretion of the Florida PSC and the FERC. On January 31, 2018, SCS, on behalf of the traditional electric operating companies (including the Company), filed with the FERC a reduction to the Company's open access transmission tariff charge for 2018 to reflect the revised federal corporate tax rate. See Note 3 to the financial statements under "Regulatory Matters" for additional information regarding the Company's rate filing to reflect the impacts of the Tax Reform Legislation.

See FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein and Note 5 to the financial statements under "Current and Deferred Income Taxes" for additional information.

The ultimate outcome of these matters cannot be determined at this time.

### *Bonus Depreciation*

Under the Tax Reform Legislation, projects with binding contracts prior to September 28, 2017 and placed in service after September 27, 2017 remain eligible for bonus depreciation under the PATH Act. The PATH Act allowed for 50% bonus depreciation for 2015 through 2017, 40% bonus depreciation for 2018, and 30% bonus depreciation for 2019 and certain long-lived assets placed in service in 2020. Based on provisional estimates, approximately $20 million of positive cash flows is expected to result from bonus depreciation for the 2017 tax year and approximately $10 million for the 2018 tax year. Should Southern Company have a NOL in 2018, all of these cash flows may not be fully realized in 2018. See Note 5 to the financial statements under "Current and Deferred Income Taxes" for additional information.

## Other Matters

As a result of the cost to comply with environmental regulations imposed by the EPA, the Company retired its coal-fired generation at Plant Smith Units 1 and 2 in March 2016. In August 2016, the Florida PSC approved the Company's request to reclassify the remaining net book value of Plant Smith Units 1 and 2 and the remaining materials and supplies associated with these units as of the retirement date, totaling approximately $63 million, to a regulatory asset. The Company began amortizing the investment balances over 15 years effective January 1, 2018 in accordance with the 2017 Rate Case Settlement Agreement.

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as standards for air, water, land, and protection of other natural resources, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by $CO_2$ and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. The ultimate outcome of such pending or potential litigation or regulatory matters cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

## ACCOUNTING POLICIES

### Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

#### *Utility Regulation*

The Company is subject to retail regulation by the Florida PSC. The Florida PSC sets the rates the Company is permitted to charge customers based on allowable costs. The Company is also subject to cost-based regulation by the FERC with respect to wholesale transmission rates. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, AROs, and pension and other postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and any requirement to refund these regulatory liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

***Federal Tax Reform Legislation***

Following the enactment of the Tax Reform Legislation, the SEC staff issued Staff Accounting Bulletin 118 – "Income Tax Accounting Implications of the Tax Cuts and Jobs Act" (SAB 118), which provides for a measurement period of up to one year from the enactment date to complete accounting under GAAP for the tax effects of the legislation. Due to the complex and comprehensive nature of the enacted tax law changes, and their application under GAAP, the Company considers all amounts recorded in the financial statements as a result of the Tax Reform Legislation to be "provisional" as discussed in SAB 118 and subject to revision. The Company is awaiting additional guidance from industry and income tax authorities in order to finalize its accounting. The ultimate impact of the Tax Reform Legislation on deferred income tax assets and liabilities and the related regulatory assets and liabilities cannot be determined at this time. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation" herein and Notes 3 and 5 to the financial statements under "Retail Regulatory Matters" and "Current and Deferred Income Taxes," respectively, for additional information.

***Asset Retirement Obligations***

AROs are computed as the fair value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities.

The liability for AROs primarily relates to the Company's facilities that are subject to the CCR Rule and to the closure of an ash pond at Plant Scholz. In addition, the Company has retirement obligations related to combustion turbines at its Pea Ridge facility, various landfill sites, a barge unloading dock, asbestos removal, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO.

The cost estimates for AROs related to the disposal of CCR are based on information using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure for those facilities impacted by the CCR Rule. As further analysis is performed and closure details are developed, the Company will continue to periodically update these cost estimates as necessary. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations – Coal Combustion Residuals" herein and Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

Given the significant judgment involved in estimating AROs, the Company considers the liabilities for AROs to be critical accounting estimates.

***Pension and Other Postretirement Benefits***

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on pension and other postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. For purposes of determining its liability related to the pension and other postretirement benefit plans, the Company discounts the future related cash flows using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments. For 2015 and prior years, the Company computed the interest cost component of its net periodic pension and other postretirement benefit plan expense using the same single-point discount rate. Beginning in 2016, the Company adopted a full yield curve approach for calculating the interest cost component whereby the discount rate for each year is applied to the liability for that specific year. As a result, the interest cost component of net periodic pension and other postretirement benefit plan expense decreased by approximately $4 million in 2016.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $2 million or less change in total annual benefit expense and a $25 million or less change in projected obligations.

See Note 2 to the financial statements for additional information regarding pension and other postretirement benefits.

***Contingent Obligations***

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's results of operations, cash flows, or financial condition.

**Recently Issued Accounting Standards**

***Revenue***

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers* (ASC 606), replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the new standard is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

Most of the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term , as well as longer-term contractual commitments, including PPAs.

The Company has completed the evaluation of all revenue streams and determined that the adoption of ASC 606 will not change the current timing of revenue recognition for such transactions. Some revenue arrangements, such as energy-related derivatives, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed separately from revenues under ASC 606. The Company has concluded contributions in aid of construction are not in scope for ASC 606 and will continue to be accounted for as an offset to property, plant, and equipment.

The new standard is effective for reporting periods beginning after December 15, 2017. The Company applied the modified retrospective method of adoption effective January 1, 2018. The Company also utilized practical expedients which allowed it to apply the standard to open contracts at the date of adoption and to reflect the aggregate effect of all modifications when identifying performance obligations and allocating the transaction price for contracts modified before the effective date. Under the modified retrospective method of adoption, prior year reported results are not restated; however, a cumulative-effect adjustment to retained earnings at January 1, 2018 is recorded. In addition, quarterly disclosures will include comparative information on 2018 financial statement line items under current guidance. The adoption of ASC 606 did not result in a cumulative-effect adjustment .

***Leases***

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged . ASU 2016-02 is effective for fiscal years beginning after December 15, 2018 and the Company will adopt the new standard effective January 1, 2019.

The Company is currently implementing an information technology system along with the related changes to internal controls and accounting policies that will support the accounting for leases under ASU 2016-02. In addition, the Company has substantially completed a detailed inventory and analysis of its leases. In terms of rental charges and duration of contracts, the most significant leases relate to a PPA, cellular towers, and barges where the Company is the lessee and to outdoor lighting and power distribution equipment where the Company is the lessor. The Company is currently analyzing pole attachment agreements and a lease determination has not been made at this time. While the Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

***Other***

On March 10, 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017-07). ASU 2017-07 requires that an employer report the service cost component in the same line item or items as other compensation costs and requires the other components of net periodic pension and postretirement benefit costs to be separately presented in the income statement outside of income from operations. Additionally, only the service cost component is eligible for capitalization, when applicable. However, all cost components remain eligible for capitalization under FERC regulations. ASU 2017-07 will be applied retrospectively for the presentation of the service cost component and the other components of net periodic pension and postretirement benefit costs in the income statement. The capitalization of only the service cost component of net periodic pension and postretirement benefit costs in assets will be applied on a prospective basis. ASU 2017-07 is effective for periods beginning after December 15, 2017. The presentation changes required for net periodic pension and postretirement benefit costs will result in a decrease in the Company's operating income and an increase in other income for 2016 and 2017 and are expected to result in a decrease in operating income and an increase in other income for 2018. The Company adopted ASU 2017-07 effective January 1, 2018 with no material impact on its financial statements.

On August 28, 2017, the FASB issued ASU No. 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities* (ASU 2017-12), amending the hedge accounting recognition and presentation requirements. ASU 2017-12 makes more financial and non-financial hedging strategies eligible for hedge accounting, amends the related presentation and disclosure requirements, and simplifies hedge effectiveness assessment requirements. ASU 2017-12 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

## FINANCIAL CONDITION AND LIQUIDITY

### Overview

The Company's financial condition remained stable at December 31, 2017 . The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to maintain existing facilities, to comply with environmental regulations including adding environmental modifications to existing generating units, to expand and improve transmission and distribution facilities, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2018 through 2020 , the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. The Company plans to finance future cash needs in excess of its operating cash flows primarily through external security issuances, equity contributions from Southern Company, and borrowings from financial institutions. The Company plans to use commercial paper to manage seasonal variations in operating cash flows and for other working capital needs. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit agreements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan increased in value as of December 31, 2017 as compared to December 31, 2016 . No contributions to the qualified pension plan were made for the year ended December 31, 2017 and no mandatory contributions to the qualified pension plan are anticipated during 2018 . See Note 2 to the financial statements under "Pension Plans" for additional information.

Net cash provided from operating activities totaled $356 million in 2017 , a decrease of $23 million from 2016 , primarily due to decreases in cash flows related to the timing of fossil fuel stock purchases and clause recovery, partially offset by increases related to voluntary contributions to the qualified pension plan in 2016. Net cash provided from operating activities totaled $379 million in 2016 , a decrease of $81 million from 2015 , primarily due to decreases in cash flows related to clause recovery and a voluntary contribution to the qualified pension plan, partially offset by the timing of fossil fuel stock purchases.

Net cash used for investing activities totaled $234 million , $180 million , and $281 million for 2017 , 2016 , and 2015 , respectively. The changes in cash used for investing activities were primarily related to gross property additions for environmental, distribution, steam generation, and transmission assets. Funds for the Company's property additions were provided by operating activities, capital contributions, and other financing activities.

Net cash used for financing activities totaled $150 million in 2017 primarily due to the payment of short-term debt, the payment of common stock dividends, and the redemption of preferred stock, partially offset by the proceeds of the issuance of long-term debt and common stock. Net cash used for financing activities totaled $217 million in 2016 primarily due to the redemptions of long-term debt and the payment of common stock dividends, partially offset by an increase in notes payable. Net cash used for financing activities totaled $144 million in 2015 primarily due to the payment of common stock dividends and redemptions of long-term debt, partially offset by an increase in notes payable and proceeds from the issuance of common stock to Southern Company. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes in 2017 primarily reflect the financing activities described above. Other significant changes, which resulted from the Tax Reform Legislation, included an increase in deferred credits related to income taxes and a decrease in accumulated deferred income taxes. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation" herein and Notes 3 and 5 to the financial statements under "Retail Regulatory Matters" and "Current and Deferred Income Taxes," respectively, for additional information and related proposed regulatory treatment.

The Company's ratio of common equity to total capitalization plus short-term debt, was 53.5% and 48.3% at December 31, 2017 and 2016 , respectively. See Note 6 to the financial statements for additional information.

**Sources of Capital**

The Company plans to obtain the funds required to meet its future capital needs from sources similar to those used in the past, which were primarily from operating cash flows, external security issuances, borrowings from financial institutions, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors.

The issuance of securities by the Company is subject to annual approval by the Florida PSC. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the Florida PSC, as well as the amounts registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company in the Southern Company system.

The Company's current liabilities may exceed current assets because of scheduled maturities of long-term debt and the periodic use of short-term debt as a funding source, as well as significant seasonal fluctuations in cash needs.

The Company intends to utilize operating cash flows, external security issuances, and borrowings from financial institutions to fund its short-term capital needs. The Company has substantial cash flow from operating activities and access to the capital markets and financial institutions to meet short-term liquidity needs.

At December 31, 2017 , the Company had approximately $28 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2017 were as follows:

| Expires | | | | | Executable Term Loans | | Expires Within One Year | |
|---|---|---|---|---|---|---|---|---|
| 2018 | 2019 | 2020 | Total | Unused | One Year | Two Years | Term Out | No Term Out |
| *(in millions)* | | | *(in millions)* | | *(in millions)* | | *(in millions)* | |
| $30 | $25 | $225 | $280 | $280 | $45 | $— | $20 | $10 |

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

In November 2017, the Company amended $195 million of its multi-year credit arrangements to extend the maturity dates from 2017 and 2018 to 2020.

Most of these bank credit arrangements contain covenants that limit debt levels and contain cross-acceleration provisions to other indebtedness (including guarantee obligations) of the Company. Such cross-acceleration provisions to other indebtedness would trigger an event of default if the Company defaulted on indebtedness, the payment of which was then accelerated. At December 31, 2017 , the Company was in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings.

**MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)**
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Subject to applicable market conditions, the Company expects to renew or replace its bank credit arrangements, as needed, prior to expiration. In connection therewith, the Company may extend the maturity dates and/or increase or decrease the lending commitments thereunder.

Most of the unused credit arrangements with banks are allocated to provide liquidity support to the Company's pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2017 was approximately $82 million. In addition, at December 31, 2017 , the Company had $75 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional electric operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each traditional electric operating company under these arrangements are several and there is no cross-affiliate credit support. Short-term borrowings are included in notes payable on the balance sheets.

Details of short-term borrowings were as follows:

| | Short-term Debt at the End of the Period | | Short-term Debt During the Period (*) | | |
|---|---|---|---|---|---|
| | Amount Outstanding | Weighted Average Interest Rate | Average Amount Outstanding | Weighted Average Interest Rate | Maximum Amount Outstanding |
| | *(in millions)* | | *(in millions)* | | *(in millions)* |
| **December 31, 2017** | | | | | |
| Commercial paper | **$ 45** | **2.0%** | **$ 20** | **1.3%** | **$ 168** |
| Short-term bank debt | **—** | **—%** | **38** | **1.6%** | **100** |
| Total | **$ 45** | **2.0%** | **$ 58** | **1.5%** | |
| **December 31, 2016** | | | | | |
| Commercial paper | $ 168 | 1.1% | $ 53 | 0.9% | $ 168 |
| Short-term bank debt | 100 | 1.5% | 64 | 1.3% | 100 |
| Total | $ 268 | 1.2% | $ 117 | 1.1% | |
| **December 31, 2015** | | | | | |
| Commercial paper | $ 142 | 0.7% | $ 101 | 0.4% | $ 175 |
| Short-term bank debt | — | —% | 10 | 0.7% | 40 |
| Total | $ 142 | 0.7% | $ 111 | 0.4% | |

(*) Average and maximum amounts are based upon daily balances during the year.

The Company believes the need for working capital can be adequately met by utilizing the commercial paper program, lines of credit, short-term bank term loans, and operating cash flows.

**Financing Activities**

In January 2017, the Company issued 1,750,000 shares of common stock to Southern Company and realized proceeds of $175 million . The proceeds were used for general corporate purposes, including the Company's continuous construction program.

In March 2017, the Company extended the maturity of a $100 million short-term floating rate bank loan bearing interest based on one-month LIBOR from April 2017 to October 2017 and subsequently repaid the loan in May 2017.

In May 2017, the Company issued $300 million aggregate principal amount of Series 2017A 3.30% Senior Notes due May 30, 2027. The proceeds, together with other funds, were used to repay at maturity $85 million aggregate principal amount of Series 2007A 5.90% Senior Notes due June 15, 2017; to repay outstanding commercial paper borrowings; to repay a $100 million short-term floating rate bank loan, as discussed above; and to redeem, in June 2017, 550,000 shares ($55 million aggregate liquidation amount) of 6.00% Series Preference Stock, 450,000 shares ($45 million aggregate liquidation amount) of Series 2007A 6.45% Preference Stock, and 500,000 shares ($50 million aggregate liquidation amount) of Series 2013A 5.60% Preference Stock.

In addition to any financings that may be necessary to meet capital requirements, contractual obligations, and storm recovery, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

**Credit Rating Risk**

At December 31, 2017 , the Company did not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, and energy price risk management.

The maximum potential collateral requirements under these contracts at December 31, 2017 were as follows:

| Credit Ratings | Maximum Potential Collateral Requirements |
|---|---|
| | *(in millions)* |
| At BBB- and/or Baa3 | $ 167 |
| Below BBB- and/or Baa3 | $ 562 |

Included in these amounts are certain agreements that could require collateral in the event that Alabama Power or Georgia Power has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact the ability of the Company to access capital markets and would be likely to impact the cost at which it does so.

On March 24, 2017, S&P revised its consolidated credit rating outlook for Southern Company and its subsidiaries (including the Company) from stable to negative.

While it is unclear how the credit rating agencies, the FERC, and the Florida PSC may respond to the Tax Reform Legislation, certain financial metrics, such as the funds from operations to debt percentage, used by the credit rating agencies to assess Southern Company and its subsidiaries, including the Company, may be negatively impacted. The Company intends to work with the Florida PSC, including working towards approval of the 2018 Tax Reform Settlement Agreement, to mitigate the adverse impacts, if any, to certain credit metrics. See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

**Market Price Risk**

Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and may enter into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives which are designated as hedges. The weighted average interest rate on $82 million of outstanding variable rate long-term debt that has not been hedged at December 31, 2017 was 1.85%. If the Company sustained a 100 basis point change in interest rates for all variable rate long-term debt, the change would not materially affect annualized interest expense at December 31, 2017 . See Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements for additional information.

To mitigate residual risks relative to movements in fuel and electricity prices, the Company enters into financial hedge contracts for natural gas purchases and physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. The Company continues to manage a fuel-hedging program implemented per the guidelines of the Florida PSC and the actual cost of fuel is recovered through the retail fuel clause. The Florida PSC extended the moratorium on the Company's fuel-hedging program until January 1, 2021 in connection with the 2017 Rate Case Settlement Agreement. The moratorium does not have an impact on the recovery of existing hedges entered into under the previously-approved hedging program. The

Company had no material change in market risk exposure for the year ended December 31, 2017 when compared to the year ended December 31, 2016 .

The changes in fair value of energy-related derivative contracts are substantially attributable to both the volume and the price of natural gas. For the years ended December 31, the changes in fair value of energy-related derivative contracts, substantially all of which are composed of regulatory hedges, were as follows:

| | **2017 Changes** | 2016 Changes |
|---|---|---|
| | Fair Value | |
| | *(in millions)* | |
| Contracts outstanding at the beginning of the period, assets (liabilities), net | **$ (24)** | $ (100) |
| Contracts realized or settled | **17** | 49 |
| Current period changes (*) | **(14)** | 27 |
| Contracts outstanding at the end of the period, assets (liabilities), net | **$ (21)** | $ (24) |

(*) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The net hedge volumes of energy-related derivative contracts were 22 million mmBtu and 51 million mmBtu as of December 31, 2017 and December 31, 2016 , respectively.

The weighted average swap contract cost above market prices was approximately $0.95 per mmBtu as of December 31, 2017 and $0.48 per mmBtu as of December 31, 2016 . Natural gas settlements are recovered through the Company's fuel cost recovery clause.

At December 31, 2017 and 2016 , substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were related to the Company's fuel-hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery clause. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented and the actual cost of fuel is recovered through the retail fuel clause.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2 of the fair value hierarchy. See Note 9 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2017 were as follows:

| | **Fair Value Measurements December 31, 2017** | | | |
|---|---|---|---|---|
| | Total | Maturity | | |
| | Fair Value | Year 1 | Years 2&3 | Years 4&5 |
| | *(in millions)* | | | |
| Level 1 | $ — | $ — | $ — | $ — |
| Level 2 | (21) | (14) | (7) | — |
| Level 3 | — | — | — | — |
| Fair value of contracts outstanding at end of period | $ (21) | $ (14) | $ (7) | $ — |

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P, or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements.

**Capital Requirements and Contractual Obligations**

The construction program of the Company is currently estimated to total $304 million for 2018 , $266 million for 2019 , $358 million for 2020 , $279 million for 2021 , and $229 million for 2022 . These amounts include capital expenditures related to contractual purchase commitments for capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental laws and regulations included in these amounts are \$65 million, \$57 million, \$83 million, \$58 million, and \$16 million for 2018 , 2019 , 2020 , 2021 , and 2022 , respectively. These estimated expenditures do not include any potential compliance costs associated with the regulation of $CO_2$ emissions from fossil fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations" and "– Global Climate Issues" herein for additional information.

The Company also anticipates costs associated with closure and monitoring of ash ponds at Plant Scholz and in accordance with the CCR Rule, which are reflected in the Company's ARO liabilities. These costs, which could change as the Company continues to refine its assumptions underlying the cost estimates and evaluate the method and timing of compliance activities, are estimated to be \$35 million, \$11 million, \$12 million, \$18 million, and \$4 million for the years 2018 , 2019 , 2020 , 2021 , and 2022 , respectively. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts; changes in environmental laws and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing generating units, to meet regulatory requirements; changes in the expected environmental compliance program; changes in FERC rules and regulations; Florida PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the FERC and the Florida PSC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, leases, pension and post-retirement benefit plans, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 10 to the financial statements for additional information.

**Contractual Obligations**

Contractual obligations at December 31, 2017 were as follows:

| | 2018 | 2019-2020 | 2021-2022 | After 2022 | Total |
|---|---|---|---|---|---|
| | | | *(in millions)* | | |
| Long-term debt [(a)] – | | | | | |
| Principal | $ — | $ 175 | $ 141 | $ 983 | $ 1,299 |
| Interest | 48 | 95 | 79 | 554 | 776 |
| Financial derivative obligations [(b)] | 14 | 7 | — | — | 21 |
| Operating leases [(c)] | 8 | 4 | 3 | 4 | 19 |
| Purchase commitments – | | | | | |
| Capital [(d)] | 304 | 594 | 508 | — | 1,406 |
| Fuel [(e)] | 211 | 247 | 132 | 44 | 634 |
| Purchased power [(f)] | 129 | 266 | 275 | 906 | 1,576 |
| Other [(g)] | 16 | 34 | 36 | 119 | 205 |
| Pension and other postretirement benefit plans [(h)] | 5 | 11 | — | — | 16 |
| Total | $ 735 | $ 1,433 | $ 1,174 | $ 2,610 | $ 5,952 |

(a) All amounts are reflected based on final maturity dates. The Company plans to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of December 31, 2017 , as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk.

(b) See Notes 1 and 10 to the financial statements for additional information.

(c) Excludes a PPA accounted for as a lease, which is included in "Purchased power."

(d) The Company provides estimated capital expenditures for a five-year period, including capital expenditures associated with environmental regulations. These amounts exclude capital expenditures covered under long-term service agreements, which are reflected in "Other." At December 31, 2017, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations" for additional information.

(e) Includes commitments to purchase coal and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2017.

(f) The capacity and transmission related costs associated with PPAs are recovered through the purchased power capacity cost recovery clause. Energy costs associated with PPAs are recovered through the fuel cost recovery clause. See Notes 3 and 7 to the financial statements for additional information.

(g) Includes long-term service agreements and contracts for the procurement of limestone. Long-term service agreements include price escalation based on inflation indices. Limestone costs are recovered through the environmental cost recovery clause. See Note 3 to the financial statements for additional information.

(h) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

**Cautionary Statement Regarding Forward-Looking Statements**

The Company's 2017 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, customer and sales growth, economic conditions, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, pending or potential litigation matters, access to sources of capital, projections for the qualified pension plan and postretirement benefit plans contributions, financing activities, start and completion of construction projects, filings with state and federal regulatory authorities, impacts of the Tax Reform Legislation, federal income tax benefits, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including environmental laws and regulations governing air, water, land, and protection of other natural resources , and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- the uncertainty surrounding the recently enacted Tax Reform Legislation, including implementing regulations and IRS interpretations, actions that may be taken in response by regulatory authorities, and its impact, if any, on the credit ratings of the Company;
- current and future litigation or regulatory investigations, proceedings, or inquiries ;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of facilities, to construct facilities in accordance with the requirements of permits and licenses , and to satisfy any environmental performance standards ;
- investment performance of the Company's employee and retiree benefit plans ;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or physical attack and the threat of physical attacks;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on foreign currency exchange rates, counterparty performance, and the economy in general ;
- the ability of the Company to obtain additional generating capacity (or sell excess generating capacity) at competitive prices;

- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports filed by the Company from time to time with the SEC.

**The Company expressly disclaims any obligation to update any forward-looking statements.**

**STATEMENTS OF INCOME**
**For the Years Ended December 31, 2017 , 2016 , and 2015**
**Gulf Power Company 2017 Annual Report**

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| **Operating Revenues:** | | | |
| Retail revenues | **$ 1,281** | $ 1,281 | $ 1,249 |
| Wholesale revenues, non-affiliates | **57** | 61 | 107 |
| Wholesale revenues, affiliates | **108** | 75 | 58 |
| Other revenues | **70** | 68 | 69 |
| Total operating revenues | **1,516** | 1,485 | 1,483 |
| **Operating Expenses:** | | | |
| Fuel | **427** | 432 | 445 |
| Purchased power | **155** | 142 | 135 |
| Other operations and maintenance | **359** | 336 | 354 |
| Depreciation and amortization | **137** | 172 | 141 |
| Taxes other than income taxes | **116** | 120 | 118 |
| Loss on Plant Scherer Unit 3 | **33** | — | — |
| Total operating expenses | **1,227** | 1,202 | 1,193 |
| **Operating Income** | **289** | 283 | 290 |
| **Other Income and (Expense):** | | | |
| Interest expense, net of amounts capitalized | **(50)** | (47) | (49) |
| Other income (expense), net | **(10)** | (5) | 8 |
| Total other income and (expense) | **(60)** | (52) | (41) |
| **Earnings Before Income Taxes** | **229** | 231 | 249 |
| Income taxes | **90** | 91 | 92 |
| **Net Income** | **139** | 140 | 157 |
| **Dividends on Preference Stock** | **4** | 9 | 9 |
| **Net Income After Dividends on Preference Stock** | **$ 135** | $ 131 | $ 148 |

The accompanying notes are an integral part of these financial statements.

**STATEMENTS OF COMPREHENSIVE INCOME**
**For the Years Ended December 31, 2017 , 2016 , and 2015**
**Gulf Power Company 2017 Annual Report**

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| **Net Income** | **$ 139** | $ 140 | $ 157 |
| Other comprehensive income (loss): | | | |
| Qualifying hedges: | | | |
| Changes in fair value, net of tax of $(1), $-, and $-, respectively | **(1)** | 1 | 1 |
| Total other comprehensive income (loss) | **(1)** | 1 | 1 |
| **Comprehensive Income** | **$ 138** | $ 141 | $ 158 |

The accompanying notes are an integral part of these financial statements.

**STATEMENTS OF CASH FLOWS**
**For the Years Ended December 31, 2017 , 2016 , and 2015**
**Gulf Power Company 2017 Annual Report**

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | *(in millions)* | | |
| **Operating Activities:** | | | |
| Net income | $ 139 | $ 140 | $ 157 |
| Adjustments to reconcile net income to net cash provided from operating activities — | | | |
| Depreciation and amortization, total | 149 | 179 | 152 |
| Deferred income taxes | 72 | 57 | 90 |
| Pension and postretirement funding | — | (48) | — |
| Loss on Plant Scherer Unit 3 | 33 | — | — |
| Other, net | (3) | (3) | 4 |
| Changes in certain current assets and liabilities — | | | |
| -Receivables | (43) | 15 | 33 |
| -Fossil fuel stock | 8 | 37 | (6) |
| -Prepaid income taxes | 8 | (11) | 32 |
| -Other current assets | (2) | (1) | (2) |
| -Accounts payable | 20 | 5 | (22) |
| -Over recovered regulatory clause revenues | (12) | 1 | 22 |
| -Other current liabilities | (13) | 8 | — |
| Net cash provided from operating activities | 356 | 379 | 460 |
| **Investing Activities:** | | | |
| Property additions | (202) | (178) | (235) |
| Cost of removal, net of salvage | (21) | (9) | (10) |
| Change in construction payables | (2) | 13 | (28) |
| Other investing activities | (9) | (6) | (8) |
| Net cash used for investing activities | (234) | (180) | (281) |
| **Financing Activities:** | | | |
| Increase (decrease) in notes payable, net | (223) | 126 | 32 |
| Proceeds — | | | |
| Common stock issued to parent | 175 | — | 20 |
| Capital contributions from parent company | 2 | 20 | 4 |
| Pollution control revenue bonds | — | — | 13 |
| Senior notes | 300 | — | — |
| Redemptions and repurchases — | | | |
| Preference stock | (150) | — | — |
| Senior notes | (85) | (235) | (60) |
| Pollution control revenue bonds | — | — | (13) |
| Payment of common stock dividends | (165) | (120) | (130) |
| Other financing activities | (4) | (8) | (10) |
| Net cash used for financing activities | (150) | (217) | (144) |
| **Net Change in Cash and Cash Equivalents** | (28) | (18) | 35 |
| **Cash and Cash Equivalents at Beginning of Year** | 56 | 74 | 39 |
| **Cash and Cash Equivalents at End of Year** | $ 28 | $ 56 | $ 74 |
| **Supplemental Cash Flow Information:** | | | |
| Cash paid (received) during the period for — | | | |
| Interest (net of $-, $-, and $6 capitalized, respectively) | $ 46 | $ 53 | $ 52 |
| Income taxes (net of refunds) | 12 | 21 | (7) |
| Noncash transactions — | | | |
| Accrued property additions at year-end | 31 | 33 | 20 |
| Other financing activities related to energy services | (7) | — | — |
| Receivables related to energy services | 7 | — | — |

The accompanying notes are an integral part of these financial statements.

**BALANCE SHEETS**
**At December 31, 2017 and 2016**
**Gulf Power Company 2017 Annual Report**

| **Assets** | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Current Assets:** | | |
| Cash and cash equivalents | **$ 28** | $ 56 |
| Receivables — | | |
| Customer accounts receivable | **76** | 72 |
| Unbilled revenues | **67** | 55 |
| Under recovered regulatory clause revenues | **27** | 17 |
| Affiliated | **14** | 17 |
| Other accounts and notes receivable | **7** | 6 |
| Accumulated provision for uncollectible accounts | **(1)** | (1) |
| Fossil fuel stock | **63** | 71 |
| Materials and supplies | **57** | 55 |
| Other regulatory assets, current | **56** | 44 |
| Other current assets | **21** | 30 |
| Total current assets | **415** | 422 |
| **Property, Plant, and Equipment:** | | |
| In service | **5,196** | 5,140 |
| Less: Accumulated provision for depreciation | **1,461** | 1,382 |
| Plant in service, net of depreciation | **3,735** | 3,758 |
| Construction work in progress | **91** | 51 |
| Total property, plant, and equipment | **3,826** | 3,809 |
| **Deferred Charges and Other Assets:** | | |
| Deferred charges related to income taxes | **31** | 58 |
| Other regulatory assets, deferred | **502** | 512 |
| Other deferred charges and assets | **23** | 21 |
| Total deferred charges and other assets | **556** | 591 |
| **Total Assets** | **$ 4,797** | $ 4,822 |

The accompanying notes are an integral part of these financial statements.

**BALANCE SHEETS**
**At December 31, 2017 and 2016**
**Gulf Power Company 2017 Annual Report**

| **Liabilities and Stockholder's Equity** | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Current Liabilities:** | | |
| Securities due within one year | **$ —** | $ 87 |
| Notes payable | **45** | 268 |
| Accounts payable — | | |
| Affiliated | **52** | 59 |
| Other | **75** | 54 |
| Customer deposits | **35** | 35 |
| Accrued taxes — | | |
| Accrued income taxes | **1** | 1 |
| Other accrued taxes | **9** | 19 |
| Accrued interest | **9** | 8 |
| Accrued compensation | **39** | 40 |
| Deferred capacity expense, current | **22** | 22 |
| Other regulatory liabilities, current | **—** | 16 |
| Asset retirement obligations, current | **37** | 16 |
| Other current liabilities | **27** | 24 |
| Total current liabilities | **351** | 649 |
| **Long-Term Debt** (See accompanying statements) | **1,285** | 987 |
| **Deferred Credits and Other Liabilities:** | | |
| Accumulated deferred income taxes | **537** | 948 |
| Deferred credits related to income taxes | **458** | 2 |
| Employee benefit obligations | **102** | 96 |
| Deferred capacity expense | **97** | 119 |
| Asset retirement obligations | **105** | 120 |
| Other cost of removal obligations | **221** | 249 |
| Other regulatory liabilities, deferred | **43** | 45 |
| Other deferred credits and liabilities | **67** | 71 |
| Total deferred credits and other liabilities | **1,630** | 1,650 |
| **Total Liabilities** | **3,266** | 3,286 |
| **Preference Stock** (See accompanying statements) | **—** | 147 |
| **Common Stockholder's Equity** (See accompanying statements) | **1,531** | 1,389 |
| **Total Liabilities and Stockholder's Equity** | **$ 4,797** | $ 4,822 |
| **Commitments and Contingent Matters** (See notes) | | |

The accompanying notes are an integral part of these financial statements.

**STATEMENTS OF CAPITALIZATION**
**At December 31, 2017 and 2016**
**Gulf Power Company 2017 Annual Report**

| | **2017** | 2016 | **2017** | 2016 |
|---|---|---|---|---|
| | *(in millions)* | | *(percent of total)* | |
| **Long-Term Debt:** | | | | |
| Long-term notes payable — | | | | |
| 2.93% to 5.90% due 2017 | **$ —** | $ 87 | | |
| 4.75% due 2020 | **175** | 175 | | |
| 3.10% due 2022 | **100** | 100 | | |
| 3.30% to 5.10% due 2027-2044 | **715** | 415 | | |
| Total long-term notes payable | **990** | 777 | | |
| Other long-term debt — | | | | |
| Pollution control revenue bonds — | | | | |
| 2.10% due 2022 | **37** | 37 | | |
| 1.15% to 4.45% due 2023-2049 | **190** | 190 | | |
| Variable rate (1.83% at 12/31/17) due 2022 | **4** | 4 | | |
| Variable rates (1.85% to 1.88% at 12/31/17) due 2039-2042 | **78** | 78 | | |
| Total other long-term debt | **309** | 309 | | |
| Unamortized debt discount | **(5)** | (5) | | |
| Unamortized debt issuance expense | **(9)** | (7) | | |
| Total long-term debt (annual interest requirement — $48 million) | **1,285** | 1,074 | | |
| Less amount due within one year | **—** | 87 | | |
| Long-term debt excluding amount due within one year | **1,285** | 987 | **45.6%** | 39.1% |
| **Preferred and Preference Stock:** | | | | |
| Authorized — 20,000,000 shares — preferred stock | | | | |
| — 10,000,000 shares — preference stock | | | | |
| Outstanding — $100 par or stated value | | | | |
| — 2017: no shares | | | | |
| — 2016: | | | | |
| — 6.00% preference stock — 550,000 shares (non-cumulative) | **—** | 54 | | |
| — 6.45% preference stock — 450,000 shares (non-cumulative) | **—** | 44 | | |
| — 5.60% preference stock — 500,000 shares (non-cumulative) | **—** | 49 | | |
| Total preference stock | **—** | 147 | **—** | 5.8 |
| **Common Stockholder's Equity:** | | | | |
| Common stock, without par value — | | | | |
| Authorized — 20,000,000 shares | | | | |
| Outstanding — 2017: 7,392,717 shares | | | | |
| — 2016: 5,642,717 shares | **678** | 503 | | |
| Paid-in capital | **594** | 589 | | |
| Retained earnings | **259** | 296 | | |
| Accumulated other comprehensive income | **—** | 1 | | |
| Total common stockholder's equity | **1,531** | 1,389 | **54.4** | 55.1 |
| **Total Capitalization** | **$ 2,816** | $ 2,523 | **100.0%** | 100.0% |

The accompanying notes are an integral part of these financial statements.

**STATEMENTS OF COMMON STOCKHOLDER'S EQUITY**
**For the Years Ended December 31, 2017 , 2016 , and 2015**
**Gulf Power Company 2017 Annual Report**

| | Number of Common Shares Issued | Common Stock | Paid-In Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|---|---|---|---|---|---|---|
| | | | | *(in millions)* | | |
| **Balance at December 31, 2014** | 5 | $ 483 | $ 560 | $ 267 | $ (1) | $ 1,309 |
| Net income after dividends on preference stock | — | — | — | 148 | — | 148 |
| Issuance of common stock | 1 | 20 | — | — | — | 20 |
| Capital contributions from parent company | — | — | 7 | — | — | 7 |
| Other comprehensive income (loss) | — | — | — | — | 1 | 1 |
| Cash dividends on common stock | — | — | — | (130) | — | (130) |
| **Balance at December 31, 2015** | 6 | 503 | 567 | 285 | — | 1,355 |
| Net income after dividends on preference stock | — | — | — | 131 | — | 131 |
| Capital contributions from parent company | — | — | 22 | — | — | 22 |
| Other comprehensive income (loss) | — | — | — | — | 1 | 1 |
| Cash dividends on common stock | — | — | — | (120) | — | (120) |
| **Balance at December 31, 2016** | **6** | **503** | **589** | **296** | **1** | **1,389** |
| Net income after dividends on preference stock | **—** | **—** | **—** | **135** | **—** | **135** |
| Issuance of common stock | **—** | **175** | **—** | **—** | **—** | **175** |
| Capital contributions from parent company | **—** | **—** | **5** | **—** | **—** | **5** |
| Other comprehensive income (loss) | **—** | **—** | **—** | **—** | **(1)** | **(1)** |
| Cash dividends on common stock | **—** | **—** | **—** | **(165)** | **—** | **(165)** |
| Other | **—** | **—** | **—** | **(7)** | **—** | **(7)** |
| **Balance at December 31, 2017** | **6** | **$ 678** | **$ 594** | **$ 259** | **$ —** | **$ 1,531** |

The accompanying notes are an integral part of these financial statements.

**NOTES TO FINANCIAL STATEMENTS**
**Gulf Power Company 2017 Annual Report**

**Index to the Notes to Financial Statements**

**NOTES (continued)**
**Gulf Power Company 2017 Annual Report**

## 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

### General

Gulf Power Company (the Company) is a wholly-owned subsidiary of Southern Company, which is the parent company of the Company and three other traditional electric operating companies, as well as Southern Power, Southern Company Gas (as of July 1, 2016), SCS, Southern Linc, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, PowerSecure (as of May 9, 2016), Inc. (PowerSecure), and other direct and indirect subsidiaries. The traditional electric operating companies – the Company, Alabama Power, Georgia Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. The Company provides electric service to retail customers in northwest Florida and to wholesale customers in the Southeast. Southern Power develops, constructs, acquires, owns, and manages power generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Company Gas distributes natural gas through utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. Southern Linc provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber optics services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases and for other electric services. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants. PowerSecure is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure.

The equity method is used for entities in which the Company has significant influence but does not control.

The Company is subject to regulation by the FERC and the Florida PSC. As such, the Company's financial statements reflect the effects of rate regulation in accordance with GAAP and comply with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

### Recently Issued Accounting Standards

#### *Revenue*

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers* (ASC 606), replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the new standard is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

Most of the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term , as well as longer-term contractual commitments, including PPAs.

The Company has completed the evaluation of all revenue streams and determined that the adoption of ASC 606 will not change the current timing of revenue recognition for such transactions. Some revenue arrangements, such as energy-related derivatives, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed separately from revenues under ASC 606. The Company has concluded contributions in aid of construction are not in scope for ASC 606 and will continue to be accounted for as an offset to property, plant, and equipment.

The new standard is effective for reporting periods beginning after December 15, 2017. The Company applied the modified retrospective method of adoption effective January 1, 2018. The Company also utilized practical expedients which allowed it to apply the standard to open contracts at the date of adoption and to reflect the aggregate effect of all modifications when identifying performance obligations and allocating the transaction price for contracts modified before the effective date. Under the modified retrospective method of adoption, prior year reported results are not restated; however, a cumulative-effect adjustment to retained earnings at January 1, 2018 is recorded. In addition, quarterly disclosures will include comparative information on 2018 financial statement line items under current guidance. The adoption of ASC 606 did not result in a cumulative-effect adjustment .

#### *Leases*

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged . ASU 2016-02 is effective for fiscal years beginning after December 15, 2018 and the Company will adopt the new standard effective January 1, 2019.

The Company is currently implementing an information technology system along with the related changes to internal controls and accounting policies that will support the accounting for leases under ASU 2016-02. In addition, the Company has substantially completed a detailed inventory and analysis of its leases. In terms of rental charges and duration of contracts, the most significant leases relate to a PPA, cellular towers, and barges where the Company is the lessee and to outdoor lighting and power distribution equipment where the Company is the lessor. The Company is currently analyzing pole attachment agreements and a lease determination has not been made at this time. While the Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

***Other***

In March 2016, the FASB issued ASU No. 2016-09, *Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Notes 5 and 8 for disclosures impacted by ASU 2016-09.

On March 10, 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017-07). ASU 2017-07 requires that an employer report the service cost component in the same line item or items as other compensation costs and requires the other components of net periodic pension and postretirement benefit costs to be separately presented in the income statement outside of income from operations. Additionally, only the service cost component is eligible for capitalization, when applicable. However, all cost components remain eligible for capitalization under FERC regulations. ASU 2017-07 will be applied retrospectively for the presentation of the service cost component and the other components of net periodic pension and postretirement benefit costs in the income statement. The capitalization of only the service cost component of net periodic pension and postretirement benefit costs in assets will be applied on a prospective basis. ASU 2017-07 is effective for periods beginning after December 15, 2017. The presentation changes required for net periodic pension and postretirement benefit costs will result in a decrease in the Company's operating income and an increase in other income for 2016 and 2017 and are expected to result in a decrease in operating income and an increase in other income for 2018. The Company adopted ASU 2017-07 effective January 1, 2018 with no material impact on its financial statements.

On August 28, 2017, the FASB issued ASU No. 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities* (ASU 2017-12), amending the hedge accounting recognition and presentation requirements. ASU 2017-12 makes more financial and non-financial hedging strategies eligible for hedge accounting, amends the related presentation and disclosure requirements, and simplifies hedge effectiveness assessment requirements. ASU 2017-12 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

**Affiliate Transactions**

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations, construction management, and power pool transactions. Costs for these services amounted to $81 million , $80 million , and $81 million during 2017 , 2016 , and 2015 , respectively. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

See Note 7 under "Operating Leases" for information on leases of cellular tower space for the Company's digital wireless communications equipment.

The Company has operating agreements with Georgia Power and Mississippi Power under which the Company owns a portion of Plant Scherer and Plant Daniel, respectively. Georgia Power operates Plant Scherer and Mississippi Power operates Plant Daniel. The Company reimbursed Georgia Power $11 million , $8 million , and $12 million and Mississippi Power $31 million , $26 million , and $27 million in 2017 , 2016 , and 2015 , respectively, for its proportionate share of related expenses. See Note 4 and Note 7 under "Operating Leases" for additional information.

Total power purchased from affiliates through the power pool, included in purchased power in the statements of income, totaled $15 million , $16 million , and $35 million in 2017, 2016, and 2015, respectively.

The Company has an agreement with Alabama Power under which Alabama Power made transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA from a combined cycle plant located in Alabama. Payments by the Company to Alabama Power for the improvements were $11 million , $12 million , and $14 million in 2017 , 2016 , and 2015 , respectively, and are expected to be approximately $10 million annually for 2018 through 2023 , when the PPA expires. These costs have been approved for recovery by the Florida PSC through the Company's purchased power capacity cost recovery clause and by the FERC in the transmission facilities cost allocation tariff.

In 2016, the Company purchased a turbine rotor assembly from Southern Power for $6.8 million .

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2017 , 2016 , or 2015 .

The traditional electric operating companies, including the Company and Southern Power, may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS, as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

### Regulatory Assets and Liabilities

The Company is subject to accounting requirements for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

| | **2017** | 2016 | Note |
|---|---|---|---|
| | *(in millions)* | | |
| Retiree benefit plans, net | **$ 166** | $ 160 | (a,b) |
| PPA charges | **119** | 141 | (b,c) |
| Closure of ash ponds | **80** | 75 | (b,d) |
| Remaining book value of retired assets | **65** | 66 | (e) |
| Environmental remediation | **52** | 44 | (b,d) |
| Other regulatory assets, net | **36** | 18 | (i) |
| Deferred income tax charges | **31** | 56 | (f) |
| Deferred return on transmission upgrades | **25** | 25 | (e) |
| Fuel-hedging assets, net | **21** | 24 | (b,h) |
| Loss on reacquired debt | **17** | 18 | (j) |
| Asset retirement obligations, net | **13** | 7 | (b,f) |
| Regulatory asset, offset to other cost of removal | **—** | 29 | (e) |
| Deferred income tax credits | **(458)** | (2) | (g) |
| Other cost of removal obligations | **(221)** | (278) | (f) |
| Property damage reserve | **(40)** | (40) | (e) |
| Over recovered regulatory clause revenues | **(11)** | (23) | (k) |
| Total regulatory assets (liabilities), net | **$ (105)** | $ 320 | |

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Recovered and amortized over the average remaining service period, which may range up to 14 years . See Note 2 for additional information.

(b) Not earning a return as offset in rate base by a corresponding asset or liability.

(c) Recovered over the life of the PPA for periods up to six years .

(d) Recovered through the environmental cost recovery clause when the remediation or the work is performed.

(e) Recorded and recovered or amortized as approved by the Florida PSC.

(f) Asset retirement and removal assets and liabilities are recorded, and deferred income tax assets are recorded, recovered, and amortized, over the related property lives, which may range up to 65 years . Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities.

(g) Deferred income tax liabilities are amortized over the related property lives, which may range up to 65 years . Includes the deferred tax liabilities as a result of the Tax Reform Legislation. Amortization of $71 million of the deferred tax liabilities at December 31, 2017 is expected to be determined by the Florida PSC at a later date. See Notes 3 and 5 for additional information.

(h) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which currently do not exceed four years . Upon final settlement, actual costs incurred are recovered through the fuel cost recovery clause.

(i) Comprised primarily of under recovered regulatory clause revenues. Other regulatory assets costs, with the exception of vacation pay, are recorded and recovered or amortized as approved by the Florida PSC. Vacation pay, including banked holiday pay, does not earn a return as offset in rate base by a corresponding liability; it is recorded as earned by employees and recovered as paid, generally within one year .

(j) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 40 years .

(k) Recorded and recovered or amortized as approved by the Florida PSC, generally within one year .

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated OCI related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" for additional information.

**Revenues**

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. The Company continuously monitors the over or under recovered fuel cost balance in light of the inherent variability in fuel costs. The Company is required to notify the Florida PSC if the projected fuel cost over or under recovery is expected to exceed 10% of the projected fuel revenue applicable for the period and indicate if an adjustment to the fuel cost recovery factor is being requested. The Company has similar retail cost recovery clauses for energy conservation costs, purchased power capacity costs, and environmental compliance costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. Annually, the Company petitions for recovery of projected costs including any true-up amounts from prior periods, and approved rates are implemented each January. See Note 3 under "Retail Regulatory Matters" for additional information.

The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

**Fuel Costs**

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida PSC.

**Income and Other Taxes**

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Federal ITCs utilized are deferred and amortized to income over the average life of the related property and state ITCs are recognized in the period in which the credit is claimed on the state income tax return. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

The Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

**Property, Plant, and Equipment**

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and cost of equity funds used during construction.

The Company's property, plant, and equipment in service consisted of the following at December 31:

| | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| Generation | **$ 3,005** | $ 3,001 |
| Transmission | **720** | 706 |
| Distribution | **1,282** | 1,241 |
| General | **188** | 191 |
| Plant acquisition adjustment | **1** | 1 |
| Total plant in service | **$ 5,196** | $ 5,140 |

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred or performed.

**Depreciation and Amortization**

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.5% for all years presented. Depreciation studies are conducted periodically to update the composite rates. These studies are approved by the Florida PSC and the FERC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. As authorized in a settlement agreement approved by the Florida PSC in 2013 (2013 Rate Case Settlement Agreement), the Company was allowed to reduce depreciation and record a regulatory asset in an aggregate amount up to $62.5 million between January 2014 and June 2017. See Note 3 under "Retail Regulatory Matters – Retail Base Rate Cases" for additional information.

**Asset Retirement Obligations and Other Costs of Removal**

AROs are computed as the present value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities. The Company has received an order from the Florida PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The liability for AROs primarily relates to facilities that are subject to the Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA in 2015 (CCR Rule), principally ash ponds, and to the closure of an ash pond at Plant Scholz. In addition, the Company has retirement obligations related to combustion turbines at its Pea Ridge facility, various landfill sites, a barge unloading dock, asbestos removal, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Florida PSC, and are reflected in the balance sheets.

Details of the AROs included on the balance sheets are as follows:

| | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| Balance at beginning of year | **$ 136** | $ 130 |
| Liabilities incurred | **—** | 1 |
| Liabilities settled | **(8)** | (1) |
| Accretion | **2** | 4 |
| Cash flow revisions | **12** | 2 |
| Balance at end of year | **$ 142** | $ 136 |

The cost estimates for AROs related to CCR are based on information as of December 31, 2017 using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure for those facilities impacted by the CCR Rule. As further analysis is performed and closure details are developed, the Company will continue to periodically update these cost estimates as necessary.

**Allowance for Funds Used During Construction**

The Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently, AFUDC increases the revenue requirement and is recovered over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. The average annual AFUDC rate was 5.73% for all years presented. AFUDC, net of income taxes, as a percentage of net income after dividends on preference stock was 0.07% , 0.00% , and 10.8% for 2017 , 2016 , and 2015 , respectively.

**Impairment of Long-Lived Assets and Intangibles**

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

**Property Damage Reserve**

The Company accrues for the cost of repairing damages from major storms and other uninsured property damages, including uninsured damages to transmission and distribution facilities, generation facilities, and other property. The costs of such damage are charged to the reserve. The Florida PSC approved annual accrual to the property damage reserve is $3.5 million , with a target level for the reserve between $48 million and $55 million . In accordance with a settlement agreement approved by the Florida PSC on April 4, 2017 (2017 Rate Case Settlement Agreement), the Company suspended further property damage reserve accruals effective April 2017. The Company may make discretionary accruals and is required to resume accruals of $3.5 million annually if the reserve falls below zero . The Company accrued total expenses of $3.5 million in each of 2017 , 2016 , and 2015 . As of December 31, 2017 and 2016 , the balance in the Company's property damage reserve totaled approximately $40 million , which is included in other regulatory liabilities, deferred on the balance sheets.

When the property damage reserve is inadequate to cover the cost of major storms, the Florida PSC can authorize a storm cost recovery surcharge to be applied to customer bills. As authorized in the 2017 Rate Case Settlement Agreement, the Company may initiate a storm surcharge to recover costs associated with any tropical systems named by the National Hurricane Center or other catastrophic storm events that reduce the property damage reserve in the aggregate by approximately $31 million ( 75% of the April 1, 2017 balance) or more. The storm surcharge would begin, on an interim basis, 60 days following the filing of a cost recovery petition, would be limited to $4.00 /month for a 1,000 KWH residential customer unless the Company incurs in excess of $100 million in qualified storm recovery costs in a calendar year, and would replenish the property damage reserve to approximately $40 million . See Note 3 under "Retail Regulatory Matters – Retail Base Rate Cases" for additional details of the 2017 Rate Case Settlement Agreement.

**Injuries and Damages Reserve**

The Company is subject to claims and lawsuits arising in the ordinary course of business. As permitted by the Florida PSC, the Company accrues for the uninsured costs of injuries and damages by charges to income amounting to $1.6 million annually. The Florida PSC has also given the Company the flexibility to increase its annual accrual above $1.6 million to the extent the balance in the reserve does not exceed $2 million and to defer expense recognition of liabilities greater than the balance in the reserve. The cost of settling claims is charged to the reserve. The injuries and damages reserve had a balance of $2.1 million and $1.4 million at December 31, 2017 , and 2016 , respectively. For 2017, $1.6 million and $0.5 million are included in other current liabilities and other deferred credits and liabilities on the balance sheet, respectively. For 2016, the $1.4 million balance is included in other current liabilities on the balance sheet. There were no liabilities in excess of the reserve balance at December 31, 2017 or 2016 .

**Cash and Cash Equivalents**

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

**Materials and Supplies**

Generally, materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

**Fuel Inventory**

Fuel inventory includes the average cost of oil, natural gas, coal, transportation, and emissions allowances. Fuel is recorded to inventory when purchased and then expensed, at weighted average cost, as used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida PSC. Emissions allowances granted by the EPA are included in inventory at zero cost.

**Financial Instruments**

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities on the balance sheets (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 9 for additional information regarding fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the Florida PSC approved fuel-hedging program result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded on a net basis in the statements of income. Cash flows from derivatives are classified on the statement of cash flows in the same category as the hedged item. The Florida PSC extended the moratorium on the Company's fuel-hedging program until January 1, 2021 in connection with the 2017 Rate Case Settlement Agreement. The moratorium does not have an impact on the recovery of existing hedges entered into under the previously-approved hedging program. See Note 10 for additional information regarding derivatives.

The Company offsets fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2017 .

The Company is exposed to potential losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

**Comprehensive Income**

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts included in net income.

**2. RETIREMENT BENEFITS**

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2017 and no mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2018 . The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the FERC. For the year ending December 31, 2018 , no other postretirement trust contributions are expected.

**Actuarial Assumptions**

The weighted average rates assumed in the actuarial calculations used to determine both the net periodic costs for the pension and other postretirement benefit plans for the following year and the benefit obligations as of the measurement date are presented below.

**NOTES (continued)**
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| Assumptions used to determine net periodic costs: | 2017 | 2016 | 2015 |
|---|---|---|---|
| **Pension plans** | | | |
| Discount rate – benefit obligations | **4.46%** | 4.71% | 4.18% |
| Discount rate – interest costs | **3.82** | 3.97 | 4.18 |
| Discount rate – service costs | **4.81** | 5.04 | 4.48 |
| Expected long-term return on plan assets | **7.95** | 8.20 | 8.20 |
| Annual salary increase | **4.46** | 4.46 | 3.59 |
| **Other postretirement benefit plans** | | | |
| Discount rate – benefit obligations | **4.25%** | 4.51% | 4.04% |
| Discount rate – interest costs | **3.56** | 3.68 | 4.04 |
| Discount rate – service costs | **4.62** | 4.88 | 4.38 |
| Expected long-term return on plan assets | **7.81** | 8.05 | 8.07 |
| Annual salary increase | **4.46** | 4.46 | 3.59 |

| Assumptions used to determine benefit obligations: | 2017 | 2016 |
|---|---|---|
| **Pension plans** | | |
| Discount rate | **3.82%** | 4.46% |
| Annual salary increase | **4.46** | 4.46 |
| **Other postretirement benefit plans** | | |
| Discount rate | **3.69%** | 4.25% |
| Annual salary increase | **4.46** | 4.46 |

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of eight different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2017 were as follows:

| | Initial Cost Trend Rate | Ultimate Cost Trend Rate | Year That Ultimate Rate is Reached |
|---|---|---|---|
| Pre-65 | 6.50% | 4.50% | 2026 |
| Post-65 medical | 5.00 | 4.50 | 2026 |
| Post-65 prescription | 10.00 | 4.50 | 2026 |

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2017 as follows:

| | 1 Percent Increase | 1 Percent Decrease |
|---|---|---|
| | *(in millions)* | |
| Benefit obligation | $ 4 | $ 3 |
| Service and interest costs | — | — |

**Pension Plans**

The total accumulated benefit obligation for the pension plans was $524 million at December 31, 2017 and $460 million at December 31, 2016 . Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2017 and 2016 were as follows:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Change in benefit obligation** | | |
| Benefit obligation at beginning of year | $ 517 | $ 480 |
| Service cost | 13 | 12 |
| Interest cost | 19 | 19 |
| Benefits paid | (20) | (17) |
| Actuarial (gain) loss | 58 | 23 |
| Balance at end of year | 587 | 517 |
| **Change in plan assets** | | |
| Fair value of plan assets at beginning of year | 491 | 420 |
| Actual return (loss) on plan assets | 81 | 39 |
| Employer contributions | 1 | 49 |
| Benefits paid | (20) | (17) |
| Fair value of plan assets at end of year | 553 | 491 |
| Accrued liability | $ (34) | $ (26) |

At December 31, 2017 , the projected benefit obligations for the qualified and non-qualified pension plans were $563 million and $25 million , respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized on the balance sheets at December 31, 2017 and 2016 related to the Company's pension plans consist of the following:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| Other regulatory assets, deferred | $ 160 | $ 153 |
| Other current liabilities | (1) | (1) |
| Employee benefit obligations | (33) | (25) |

Presented below are the amounts included in regulatory assets at December 31, 2017 and 2016 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2018 .

| | 2017 | 2016 | Estimated Amortization in 2018 |
|---|---|---|---|
| | | *(in millions)* | |
| Prior service cost | $ 2 | $ 3 | $ — |
| Net (gain) loss | 158 | 150 | 10 |
| Regulatory assets | $ 160 | $ 153 | |

**NOTES (continued)**
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The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2017 and 2016 are presented in the following table:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Regulatory assets:** | | |
| Beginning balance | **$ 153** | $ 142 |
| Net (gain) loss | **15** | 16 |
| Change in prior service costs | **—** | 2 |
| Reclassification adjustments: | | |
| Amortization of prior service costs | **(1)** | (1) |
| Amortization of net gain (loss) | **(7)** | (6) |
| Total reclassification adjustments | **(8)** | (7) |
| Total change | **7** | 11 |
| Ending balance | **$ 160** | $ 153 |

Components of net periodic pension cost were as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| Service cost | **$ 13** | $ 12 | $ 12 |
| Interest cost | **19** | 19 | 20 |
| Expected return on plan assets | **(38)** | (34) | (32) |
| Recognized net (gain) loss | **7** | 6 | 9 |
| Net amortization | **1** | 1 | 1 |
| Net periodic pension cost | **$ 2** | $ 4 | $ 10 |

Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2017 , estimated benefit payments were as follows:

| | Benefit Payments |
|---|---|
| | *(in millions)* |
| 2018 | $ 22 |
| 2019 | 23 |
| 2020 | 25 |
| 2021 | 26 |
| 2022 | 28 |
| 2023 to 2027 | 155 |

**NOTES (continued)**
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**Other Postretirement Benefits**

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2017 and 2016 were as follows:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Change in benefit obligation** | | |
| Benefit obligation at beginning of year | **$ 83** | $ 81 |
| Service cost | **1** | 1 |
| Interest cost | **3** | 3 |
| Benefits paid | **(5)** | (4) |
| Actuarial (gain) loss | **1** | 2 |
| Balance at end of year | **83** | 83 |
| **Change in plan assets** | | |
| Fair value of plan assets at beginning of year | **18** | 17 |
| Actual return (loss) on plan assets | **3** | 2 |
| Employer contributions | **4** | 3 |
| Benefits paid | **(5)** | (4) |
| Fair value of plan assets at end of year | **20** | 18 |
| Accrued liability | **$ (63)** | $ (65) |

Amounts recognized on the balance sheets at December 31, 2017 and 2016 related to the Company's other postretirement benefit plans consist of the following:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| Other regulatory assets, deferred | **$ 8** | $ 11 |
| Other current liabilities | **(1)** | (1) |
| Other regulatory liabilities, deferred | **(2)** | (4) |
| Employee benefit obligations | **(62)** | (64) |

Approximately $6 million and $7 million was included in net regulatory assets at December 31, 2017 and 2016 , respectively, related to the net loss for the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost. The estimated amortization of such amounts for 2018 is immaterial.

The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2017 and 2016 are presented in the following table:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Net regulatory assets (liabilities):** | | |
| Beginning balance | **$ 7** | $ 5 |
| Net (gain) loss | **(1)** | 2 |
| Ending balance | **$ 6** | $ 7 |

Components of the other postretirement benefit plans' net periodic cost were as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| Service cost | **$ 1** | $ 1 | $ 1 |
| Interest cost | **3** | 3 | 3 |
| Expected return on plan assets | **(1)** | (1) | (1) |
| Net periodic postretirement benefit cost | **$ 3** | $ 3 | $ 3 |

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

| | **Benefit Payments** | **Subsidy Receipts** | **Total** |
|---|---|---|---|
| | | *(in millions)* | |
| 2018 | $ 5 | $ — | $ 5 |
| 2019 | 5 | — | 5 |
| 2020 | 5 | — | 5 |
| 2021 | 6 | (1) | 5 |
| 2022 | 6 | (1) | 5 |
| 2023 to 2027 | 28 | (2) | 26 |

**Benefit Plan Assets**

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended. The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

**NOTES (continued)**
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The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2017 and 2016 , along with the targeted mix of assets for each plan, is presented below:

| | Target | **2017** | 2016 |
|---|---|---|---|
| **Pension plan assets:** | | | |
| Domestic equity | 26% | **31%** | 29% |
| International equity | 25 | **25** | 22 |
| Fixed income | 23 | **24** | 29 |
| Special situations | 3 | **1** | 2 |
| Real estate investments | 14 | **13** | 13 |
| Private equity | 9 | **6** | 5 |
| Total | 100% | **100%** | 100% |
| **Other postretirement benefit plan assets:** | | | |
| Domestic equity | 25% | **30%** | 28% |
| International equity | 24 | **24** | 21 |
| Domestic fixed income | 25 | **26** | 31 |
| Special situations | 3 | **1** | 2 |
| Real estate investments | 14 | **13** | 13 |
| Private equity | 9 | **6** | 5 |
| Total | 100% | **100%** | 100% |

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns and interest rates, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices. Management believes the portfolio is well-diversified with no significant concentrations of risk.

***Investment Strategies***

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

***Benefit Plan Asset Fair Values***

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2017 and 2016 . The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- ***Domestic and international equity.*** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- ***Fixed income.*** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- ***Real estate investments, private equity, and special situations investments.*** Investments in real estate, private equity, and special situations are generally classified as Net Asset Value as a Practical Expedient, since the underlying assets typically do not have publicly available observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. Techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, discounted cash flow analysis, prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals. The fair value of partnerships is determined by aggregating the value of the underlying assets less liabilities.

The fair values of pension plan assets as of December 31, 2017 and 2016 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| **As of December 31, 2017:** | **Quoted Prices in Active Markets for Identical Assets (Level 1)** | **Significant Other Observable Inputs (Level 2)** | **Significant Unobservable Inputs (Level 3)** | **Net Asset Value as a Practical Expedient (NAV)** | **Total** |
| | | | *(in millions)* | | |
| Assets: | | | | | |
| Domestic equity (*) | $ 112 | $ 54 | $ — | $ — | $ 166 |
| International equity (*) | 72 | 65 | — | — | 137 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 39 | — | — | 39 |
| Corporate bonds | — | 57 | — | — | 57 |
| Pooled funds | — | 30 | — | — | 30 |
| Cash equivalents and other | 10 | — | — | — | 10 |
| Real estate investments | 22 | — | — | 55 | 77 |
| Special situations | — | — | — | 8 | 8 |
| Private equity | — | — | — | 31 | 31 |
| Total | $ 216 | $ 245 | $ — | $ 94 | $ 555 |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

**NOTES (continued)**
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| As of December 31, 2016: | Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Net Asset Value as a Practical Expedient (NAV) | Total |
|---|---|---|---|---|---|
| | | | *(in millions)* | | |
| Assets: | | | | | |
| Domestic equity (*) | $ 93 | $ 43 | $ — | $ — | $ 136 |
| International equity (*) | 57 | 52 | — | — | 109 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 27 | — | — | 27 |
| Mortgage- and asset-backed securities | — | 1 | — | — | 1 |
| Corporate bonds | — | 47 | — | — | 47 |
| Pooled funds | — | 24 | — | — | 24 |
| Cash equivalents and other | 46 | — | — | — | 46 |
| Real estate investments | 14 | — | — | 53 | 67 |
| Special situations | — | — | — | 8 | 8 |
| Private equity | — | — | — | 25 | 25 |
| Total | $ 210 | $ 194 | $ — | $ 86 | $ 490 |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

The fair values of other postretirement benefit plan assets as of December 31, 2017 and 2016 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

| As of December 31, 2017: | Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Net Asset Value as a Practical Expedient (NAV) | Total |
|---|---|---|---|---|---|
| | | | *(in millions)* | | |
| Assets: | | | | | |
| Domestic equity (*) | $ 4 | $ 2 | $ — | $ — | $ 6 |
| International equity (*) | 2 | 2 | — | — | 4 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 1 | — | — | 1 |
| Corporate bonds | — | 2 | — | — | 2 |
| Pooled funds | — | 1 | — | — | 1 |
| Cash equivalents and other | 1 | — | — | — | 1 |
| Real estate investments | 1 | — | — | 2 | 3 |
| Private equity | — | — | — | 1 | 1 |
| Total | $ 8 | $ 8 | $ — | $ 3 | $ 19 |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

**NOTES (continued)**
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| As of December 31, 2016: | Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Net Asset Value as a Practical Expedient (NAV) | Total |
|---|---|---|---|---|---|
| | | | (in millions) | | |
| Assets: | | | | | |
| Domestic equity (*) | $ 3 | $ 2 | $ — | $ — | $ 5 |
| International equity (*) | 2 | 2 | — | — | 4 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 1 | — | — | 1 |
| Corporate bonds | — | 2 | — | — | 2 |
| Pooled funds | — | 1 | — | — | 1 |
| Cash equivalents and other | 2 | — | — | — | 2 |
| Real estate investments | 1 | — | — | 2 | 3 |
| Private equity | — | — | — | 1 | 1 |
| Total | $ 8 | $ 8 | $ — | $ 3 | $ 19 |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

**Employee Savings Plan**

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company matches a portion of the first 6% of employee base salary contributions. The maximum Company match is 5.1% of an employee's base salary. Total matching contributions made to the plan for 2017 , 2016 , and 2015 were $5 million , $5 million , and $4 million , respectively.

## 3. CONTINGENCIES AND REGULATORY MATTERS

### General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as standards for air, water, land, and protection of natural resources has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by $CO_2$ and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

### Environmental Matters

***Environmental Remediation***

The Company must comply with environmental laws and regulations governing the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up affected sites. The Company received authority from the Florida PSC to recover approved environmental compliance costs through the environmental cost recovery clause. The Florida PSC reviews costs and adjusts rates up or down annually.

The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable and reasonably estimable. At December 31, 2017 and 2016, the Company's environmental remediation liability included estimated costs of environmental remediation projects of approximately $52 million and $44 million , respectively, of which approximately

$5 million and $4 million , respectively, is included in under recovered regulatory clause revenues and other current liabilities and approximately $47 million and $40 million , respectively, is included in other regulatory assets, deferred and other deferred credits and liabilities. These estimated costs primarily relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at the Company's substations. The schedule for completion of the remediation projects is subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through the Company's environmental cost recovery clause; therefore, these liabilities have no impact on net income.

The final outcome of these matters cannot be determined at this time. However, the final disposition of these matters is not expected to have a material impact on the Company's financial statements.

**FERC Matters**

The Company has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies (including the Company) and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In 2015, the FERC issued an order finding that the traditional electric operating companies' (including the Company's) and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional electric operating companies (including the Company) and Southern Power filed a request for rehearing and filed their response with the FERC in 2015.

In December 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. On May 17, 2017, the FERC accepted the traditional electric operating companies' (including the Company's) and Southern Power's compliance filing accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

On October 25, 2017, the FERC issued an order in response to the traditional electric operating companies' (including the Company's) and Southern Power's June 29, 2017 triennial updated market power analysis. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show cause within 60 days why market-based rate authority should not be revoked in certain areas adjacent to the area presently under mitigation in accordance with the February 2, 2017 order or to provide a mitigation plan to further address market power concerns. On November 10, 2017, the traditional electric operating companies (including the Company) and Southern Power responded to the FERC and proposed to resolve matters by applying the alternative mitigation authorized by the February 2, 2017 order to the adjacent areas made the subject of the October 25, 2017 order.

The ultimate outcome of these matters cannot be determined at this time.

**Retail Regulatory Matters**

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates.

***Retail Base Rate Cases***

In the 2013 Rate Case Settlement Agreement, the Florida PSC authorized the Company to reduce depreciation and record a regulatory asset up to $62.5 million from January 2014 through June 2017. In any given month, such depreciation reduction was not to exceed the amount necessary for the retail ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized retail ROE range then in effect. For 2014 and 2015, the Company recognized reductions in depreciation of $8.4 million and $20.1 million , respectively. No net reduction in depreciation was recorded in 2016. In 2017, the Company recognized the remaining $34.0 million reduction in depreciation.

On April 4, 2017, the Florida PSC approved the 2017 Rate Case Settlement Agreement among the Company and three intervenors with respect to the Company's request in 2016 to increase retail base rates. Among the terms of the 2017 Rate Case Settlement Agreement, the Company increased rates effective with the first billing cycle in July 2017 to provide an annual overall net customer impact of approximately $54.3 million . The net customer impact consisted of a $62.0 million increase in annual base revenues, less an annual purchased power capacity cost recovery clause credit for certain wholesale revenues of approximately $8 million through December 2019. In addition, the Company continued its authorized retail ROE midpoint ( 10.25% ) and range ( 9.25% to 11.25% ), is deemed to have a maximum equity ratio of 52.5% for all retail regulatory purposes, and implemented new dismantlement accruals effective July 1, 2017. The Company also began amortizing the regulatory asset associated with the investment balances remaining after the retirement of Plant Smith Units 1 and 2 ( 357 MWs) over 15 years effective January 1, 2018 and implemented new depreciation rates effective January 1, 2018. The 2017 Rate Case Settlement Agreement also resulted in a $32.5 million write-down of the Company's ownership of Plant Scherer Unit 3 ( 205 MWs), which was recorded in the first quarter 2017. The remaining issues related to the inclusion of the Company's investment in Plant Scherer Unit 3 in retail rates have been resolved as a result of the 2017 Rate Case Settlement Agreement, including recoverability of certain costs associated with the ongoing ownership and operation of the unit through the environmental cost recovery clause.

The 2017 Rate Case Settlement Agreement set forth a process for addressing the revenue requirement effects of the Tax Reform Legislation through a prospective change to the Company's base rates. Under the terms of the 2017 Rate Case Settlement Agreement, by March 1, 2018, the Company must identify the revenue requirements impacts and defer them to a regulatory asset or regulatory liability to be considered for prospective application in a change to base rates in a limited scope proceeding before the Florida PSC. In lieu of this approach, on February 14, 2018, the parties to the 2017 Rate Case Settlement Agreement filed a new stipulation and settlement agreement (2018 Tax Reform Settlement Agreement) with the Florida PSC. If approved, the 2018 Tax Reform Settlement Agreement will result in annual reductions of $18.2 million to the Company's base rates and $15.6 million to the Company's environmental cost recovery rates effective beginning the first calendar month following approval.

The 2018 Tax Reform Settlement Agreement also provides for a one-time refund of $69.4 million for the retail portion of unprotected (not subject to normalization) deferred tax liabilities through the Company's fuel cost recovery rate over the remainder of 2018. In addition, a limited scope proceeding to address the flow back of protected deferred tax liabilities will be initiated by May 1, 2018 and the Company will record a regulatory liability for the related 2018 amounts eligible to be returned to customers consistent with IRS normalization principles. Unless otherwise agreed to by the parties to the 2018 Tax Reform Settlement Agreement, amounts recorded in this regulatory liability will be refunded to retail customers in 2019 through the Company's fuel cost recovery rate.

If the 2018 Tax Reform Settlement Agreement is approved, the 2017 Rate Case Settlement Agreement will be amended to increase the Company's maximum equity ratio from 52.5% to 53.5% for regulatory purposes.

The ultimate outcome of these matters cannot be determined at this time.

***Cost Recovery Clauses***

As discussed previously, the 2017 Rate Case Settlement Agreement resolved the remaining issues related to the Company's inclusion of certain costs associated with the ongoing ownership and operation of Plant Scherer Unit 3 in the environmental cost recovery clause and no adjustment to the environmental cost recovery clause rate approved by the Florida PSC in November 2016 was made.

On October 25, 2017, the Florida PSC approved the Company's annual clause rate request for its fuel, purchased power capacity, environmental, and energy conservation cost recovery factors for 2018. The net effect of the approved changes is a $63 million increase in annual revenues effective in January 2018, the majority of which will be offset by related expense increases.

Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment.

*Retail Fuel Cost Recovery*

The Company has established fuel cost recovery rates as approved by the Florida PSC. If, at any time during the year, the projected year-end fuel cost over or under recovery balance exceeds 10% of the projected fuel revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the fuel cost recovery factor is being requested.

At December 31, 2017 , the under recovered fuel balance was approximately $22 million , which is included in under recovered regulatory clause revenues on the balance sheet. At December 31, 2016 , the over recovered fuel balance was approximately $15 million , which is included in other regulatory liabilities, current on the balance sheet.

*Purchased Power Capacity Recovery*

The Company has established purchased power capacity cost recovery rates as approved by the Florida PSC. If the projected year-end purchased power capacity cost over or under recovery balance exceeds 10% of the projected purchased power capacity revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the purchased power capacity cost recovery factor is being requested.

At December 31, 2017 , the under recovered purchased power capacity balance was $2 million , which is included in under recovered regulatory clause revenues on the balance sheet. At December 31, 2016 , the balance was immaterial.

*Environmental Cost Recovery*

The Florida Legislature adopted legislation for an environmental cost recovery clause, which allows an electric utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Such environmental costs include operations and maintenance expenses, emissions allowance expense, depreciation, and a return on net average investment. This legislation also allows recovery of costs incurred as a result of an agreement between the Company and the FDEP for the purpose of ensuring compliance with ozone ambient air quality standards adopted by the EPA.

Annually, the Company seeks recovery of projected costs including any true-up amounts from prior periods. At December 31, 2017 and 2016 , the over recovered environmental balance of approximately $11 million and $8 million , respectively, along with the current portion of projected environmental expenditures, was included in under recovered regulatory clause revenues on the balance sheets.

*Energy Conservation Cost Recovery*

Every five years , the Florida PSC establishes new numeric conservation goals covering a 10 -year period for utilities to reduce annual energy and seasonal peak demand using demand-side management (DSM) programs. After the goals are established, utilities develop plans and programs to meet the approved goals. The costs for these programs are recovered through rates established annually in the energy conservation cost recovery (ECCR) clause.

At December 31, 2017 , the under recovered ECCR balance was immaterial. At December 31, 2016 , the balance was approximately $4 million , which is included in under recovered regulatory clause revenues on the balance sheet.

**Other Matters**

As a result of the cost to comply with environmental regulations imposed by the EPA, the Company retired its coal-fired generation at Plant Smith Units 1 and 2 in March 2016. In August 2016, the Florida PSC approved the Company's request to reclassify the remaining net book value of Plant Smith Units 1 and 2 and the remaining materials and supplies associated with these units as of the retirement date, totaling approximately $63 million , to a regulatory asset. The Company began amortizing the investment balances over 15 years effective January 1, 2018 in accordance with the 2017 Rate Case Settlement Agreement.

## 4. JOINT OWNERSHIP AGREEMENTS

The Company and Mississippi Power jointly own Plant Daniel Units 1 and 2, which together represent capacity of 1,000 MWs. Plant Daniel is a generating plant located in Jackson County, Mississippi. In accordance with the operating agreement, Mississippi Power acts as the Company's agent with respect to the construction, operation, and maintenance of these units.

The Company and Georgia Power jointly own the 818 -MW capacity Plant Scherer Unit 3. Plant Scherer is a generating plant located near Forsyth, Georgia. In accordance with the operating agreement, Georgia Power acts as the Company's agent with respect to the construction, operation, and maintenance of the unit.

At December 31, 2017 , the Company's percentage ownership and investment in these jointly-owned facilities were as follows:

| | Plant Scherer Unit 3 (coal) | Plant Daniel Units 1 & 2 (coal) |
|---|---|---|
| | *(in millions)* | |
| Plant in service | $ 374 | $ 696 |
| Accumulated depreciation | 147 | 225 |
| Construction work in progress | 9 | 4 |
| Company ownership | 25% | 50% |

The Company's proportionate share of its plant operating expenses is included in the corresponding operating expenses in the statements of income and the Company is responsible for providing its own financing.

## 5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and various combined and separate state income tax returns. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

### Federal Tax Reform Legislation

Following the enactment of the Tax Reform Legislation, the SEC staff issued Staff Accounting Bulletin 118 – "Income Tax Accounting Implications of the Tax Cuts and Jobs Act" (SAB 118), which provides for a measurement period of up to one year from the enactment date to complete accounting under GAAP for the tax effects of the legislation. Due to the complex and comprehensive nature of the enacted tax law changes, and their application under GAAP, the Company considers all amounts recorded in the financial statements as a result of the Tax Reform Legislation to be "provisional" as discussed in SAB 118 and subject to revision. The Company is awaiting additional guidance from industry and income tax authorities in order to finalize its accounting. The ultimate impact of the Tax Reform Legislation on deferred income tax assets and liabilities and the related regulatory assets and liabilities cannot be determined at this time. See Note 3 under "Retail Regulatory Matters" for additional information.

### Current and Deferred Income Taxes

Details of income tax provisions are as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| Federal - | | | |
| Current | **$ 19** | $ 34 | $ (3) |
| Deferred | **58** | 45 | 80 |
| | **77** | 79 | 77 |
| State - | | | |
| Current | **(1)** | — | 5 |
| Deferred | **14** | 12 | 10 |
| | **13** | 12 | 15 |
| Total | **$ 90** | $ 91 | $ 92 |

**NOTES (continued)**
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The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| Deferred tax liabilities- | | |
| Accelerated depreciation | **$ 552** | $ 834 |
| Property basis differences | **105** | 123 |
| Pension and other employee benefits | **38** | 58 |
| Regulatory assets | **22** | 45 |
| Regulatory assets associated with employee benefit obligations | **44** | 65 |
| Regulatory assets associated with asset retirement obligations | **38** | 55 |
| Other | **13** | 12 |
| Total | **812** | 1,192 |
| Deferred tax assets- | | |
| Federal effect of state deferred taxes | **25** | 37 |
| Postretirement benefits | **17** | 26 |
| Pension and other employee benefits | **49** | 72 |
| Property differences | **98** | 1 |
| Regulatory liability associated with Tax Reform Legislation (not subject to normalization) | **19** | — |
| Property reserve | **10** | 17 |
| Asset retirement obligations | **38** | 55 |
| Alternative minimum tax carryforward | **7** | 18 |
| Other | **12** | 18 |
| Total | **275** | 244 |
| Accumulated deferred income taxes | **$ 537** | $ 948 |

The implementation of the Tax Reform Legislation significantly reduced accumulated deferred income taxes, partially offset by bonus depreciation provisions in the Protecting Americans from Tax Hikes Act. The Tax Reform Legislation also significantly reduced tax-related regulatory assets and increased tax-related regulatory liabilities.

At December 31, 2017 , tax-related regulatory assets to be recovered from customers were $31 million . These assets are primarily attributable to tax benefits flowed through to customers in prior years, deferred taxes previously recognized at rates lower than the current enacted tax law, and taxes applicable to capitalized interest.

At December 31, 2017 , the tax-related regulatory liabilities to be credited to customers were $458 million . These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and unamortized ITCs.

**Effective Tax Rate**

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| Federal statutory rate | **35.0%** | 35.0% | 35.0% |
| State income tax, net of federal deduction | **3.7** | 3.4 | 3.9 |
| Non-deductible book depreciation | **0.2** | 0.6 | 0.5 |
| Differences in prior years' deferred and current tax rates | **—** | (0.1) | (0.1) |
| AFUDC equity | **—** | — | (1.8) |
| Other, net | **0.5** | 0.6 | (0.6) |
| Effective income tax rate | **39.4%** | 39.5% | 36.9% |

In March 2016, the FASB issued ASU 2016-09, which changed the accounting for income taxes for share-based payment award transactions. Entities are required to recognize all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation as income tax expense or benefit in the income statement. The adoption of ASU 2016-09 did not have a material impact on the Company's overall effective tax rate. See Note 1 under "Recently Issued Accounting Standards" for additional information.

**Unrecognized Tax Benefits**

The Company has no material unrecognized tax benefits for the periods presented. The Company classifies interest on tax uncertainties as interest expense. Accrued interest for unrecognized tax benefits was immaterial and the Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months . The settlement of federal and state audits could impact the balances, but an estimate of the range of reasonably possible outcomes cannot be determined at this time.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2016. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2011.

## 6. FINANCING

**Securities Due Within One Year**

At December 31, 2017 , the Company had no long-term debt due within one year . At December 31, 2016 , the Company had $87 million of long-term debt due within one year .

Maturities through 2022 applicable to total long-term debt include $175 million in 2020 and $141 million in 2022. There are no scheduled maturities in 2018, 2019, or 2021.

**Bank Term Loans**

At December 31, 2016 , the Company had $100 million of bank term loans outstanding. In March 2017, the Company extended the maturity of its $100 million short-term floating rate bank loan bearing interest based on one -month LIBOR from April 2017 to October 2017 and subsequently repaid the loan in May 2017.

**Senior Notes**

At December 31, 2017 and 2016 , the Company had a total of $990 million and $777 million of senior notes outstanding, respectively. These senior notes are effectively subordinate to all secured debt of the Company, which totaled approximately $41 million at both December 31, 2017 and 2016 .

In May 2017, the Company issued $300 million aggregate principal amount of Series 2017A 3.30% Senior Notes due May 30, 2027. The proceeds, together with other funds, were used to repay at maturity $85 million aggregate principal amount of Series 2007A 5.90% Senior Notes due June 15, 2017, to repay outstanding commercial paper borrowings, to repay a $100 million short-term floating rate bank loan, and to redeem, in June 2017, all outstanding shares of preference stock. See "Bank Term Loans" and "Outstanding Classes of Capital Stock" herein for more information.

**Pollution Control Revenue Bonds**

Pollution control revenue bond obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bond obligations outstanding at December 31, 2017 and 2016 was $309 million .

**Outstanding Classes of Capital Stock**

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company's preferred stock and Class A preferred stock, without preference between classes, would rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. No shares of preferred stock or Class A preferred stock were outstanding at December 31, 2017 . The Company's preference stock would rank senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. No shares of preference stock were outstanding at December 31, 2017 . In June 2017, the Company redeemed 550,000 shares ( $55 million aggregate liquidation amount) of 6.00% Series Preference Stock, 450,000 shares ( $45 million aggregate liquidation amount) of Series 2007A 6.45% Preference Stock, and 500,000 shares ( $50 million aggregate liquidation amount) of Series 2013A 5.60% Preference Stock.

In January 2017, the Company issued 1,750,000 shares of common stock to Southern Company and realized proceeds of $175 million . The proceeds were used for general corporate purposes, including the Company's continuous construction program.

**Dividend Restrictions**

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

**Assets Subject to Lien**

The Company has granted a lien on its property at Plant Daniel in connection with the issuance of two series of pollution control revenue bonds with an aggregate outstanding principal amount of $41 million as of December 31, 2017 . There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its subsidiaries.

**Bank Credit Arrangements**

At December 31, 2017 , committed credit arrangements with banks were as follows:

| Expires | | | | | Executable Term Loans | | Expires Within One Year | |
|---|---|---|---|---|---|---|---|---|
| 2018 | 2019 | 2020 | Total | Unused | One Year | Two Years | Term Out | No Term Out |
| (in millions) | | | (in millions) | | (in millions) | | (in millions) | |
| $ 30 | $ 25 | $ 225 | $ 280 | $ 280 | $ 45 | $ — | $ 20 | $ 10 |

In November 2017, the Company amended $195 million of its multi-year credit arrangements to extend the maturity dates from 2017 and 2018 to 2020.

Most of the bank credit arrangements require payment of commitment fees based on the unused portion of the commitments. Commitment fees average less than $^{1}/_{4}$ of 1% for the Company.

Subject to applicable market conditions, the Company expects to renew or replace its bank credit arrangements as needed, prior to expiration. In connection therewith, the Company may extend the maturity dates and/or increase or decrease the lending commitments thereunder.

Most of these bank credit arrangements contain covenants that limit the Company's debt level to 65% of total capitalization, as defined in the arrangements. For purposes of these definitions, debt excludes certain hybrid securities. At December 31, 2017 , the Company was in compliance with these covenants.

Most of the $280 million of unused credit arrangements with banks provide liquidity support to the Company's pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2017 was approximately $82 million . In addition, at December 31, 2017 , the Company had $75 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months .

For short-term cash needs, the Company borrows primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangements described above. The Company may also borrow through various other arrangements with banks. Commercial paper and short-term bank loans are included in notes payable on the balance sheets.

Details of short-term borrowings were as follows:

| | | Short-term Debt at the End of the Period | |
|---|---|---|---|
| | | Amount Outstanding | Weighted Average Interest Rate |
| | | *(in millions)* | |
| **December 31, 2017:** | | | |
| Commercial paper | **$** | **45** | **2.0%** |
| **December 31, 2016:** | | | |
| Commercial paper | $ | 168 | 1.1% |
| Short-term bank debt | | 100 | 1.5% |
| Total | $ | 268 | 1.2% |

## 7. COMMITMENTS

### Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil fuel which are not recognized on the balance sheets. In 2017 , 2016 , and 2015 , the Company incurred fuel expense of $427 million , $432 million , and $445 million , respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

In addition, the Company has entered into various long-term commitments for the purchase of capacity, energy, and transmission, some of which are accounted for as operating leases. The energy-related costs associated with PPAs are recovered through the fuel cost recovery clause. The capacity and transmission-related costs associated with PPAs are recovered through the purchased power capacity cost recovery clause. Capacity expense under a PPA accounted for as an operating lease was $75 million each year for 2017 , 2016 , and 2015 .

Estimated total minimum long-term commitments at December 31, 2017 were as follows:

| | | Operating Lease PPA |
|---|---|---|
| | | *(in millions)* |
| 2018 | $ | 79 |
| 2019 | | 79 |
| 2020 | | 79 |
| 2021 | | 79 |
| 2022 | | 79 |
| 2023 and thereafter | | 33 |
| Total | $ | 428 |

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other traditional electric operating companies and Southern Power. Under these agreements, each of the traditional electric operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional electric operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

### Operating Leases

In addition to the operating lease PPA discussed above, the Company has entered into operating leases with Southern Linc and other third parties for the use of cellular tower space. These agreements have initial terms ranging from five to 10 years and renewal options of up to five years. The Company also has other operating lease agreements with various terms and expiration dates. Total lease payments were $10 million , $9 million , and $14 million for 2017 , 2016 , and 2015 , respectively. The Company includes any step rents, fixed escalations, and reasonably assured renewal periods in its computation of minimum lease payments.

Estimated total minimum lease payments under these operating leases at December 31, 2017 were as follows:

| | Minimum Lease Payments | | |
|---|---|---|---|
| | Affiliate Operating Leases (a) | Non-Affiliate Operating Leases (b) | Total |
| | | *(in millions)* | |
| 2018 | $ 2 | $ 7 | $ 9 |
| 2019 | 1 | 1 | 2 |
| 2020 | 1 | 1 | 2 |
| 2021 | 1 | — | 1 |
| 2022 | 1 | — | 1 |
| 2023 and thereafter | 4 | 1 | 5 |
| Total | $ 10 | $ 10 | $ 20 |

(a) Includes operating leases for cellular tower space.

(b) Includes operating leases for barges, facilities, and other equipment.

The Company also has operating lease agreements for railcars, barges, and towboats for the transport of coal. The Company has the option to renew the leases at the end of the lease term. The Company's lease costs, charged to fuel inventory and recovered through the retail fuel cost recovery clause, were $7 million in 2017 , $5 million in 2016 , and $10 million in 2015 . The Company's annual barge and towboat payments for 2018 are expected to be approximately $6 million .

## 8. STOCK COMPENSATION

### Stock-Based Compensation

Stock-based compensation primarily in the form of Southern Company performance share units and restricted stock units may be granted through the Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. In 2015 and 2016, stock-based compensation consisted exclusively of performance share units. Beginning in 2017, stock-based compensation granted to employees includes restricted stock units in addition to performance share units. Prior to 2015, stock-based compensation also included stock options. As of December 31, 2017 , there were 168 current and former employees participating in the stock option, performance share unit, and restricted stock unit programs.

***Performance Share Units***

Performance share units granted to employees vest at the end of a three -year performance period. All unvested performance share units vest immediately upon a change in control where Southern Company is not the surviving corporation. Shares of Southern Company common stock are delivered to employees at the end of the performance period with the number of shares issued ranging from 0% to 200% of the target number of performance share units granted, based on achievement of the performance goals established by the Compensation Committee of the Southern Company Board of Directors.

Southern Company issues performance share units with performance goals based on three performance goals to employees. These include performance share units with performance goals based on the total shareholder return (TSR) for Southern Company common stock during the three -year performance period as compared to a group of industry peers, performance share units with performance goals based on Southern Company's cumulative earnings per share (EPS) over the performance period, and performance share units with performance goals based on Southern Company's equity-weighted ROE over the performance period.

In 2015 and 2016, the EPS-based and ROE-based awards each represented 25% of the total target grant date fair value of the performance share unit awards granted. The remaining 50% of the total target grant date fair value consisted of TSR-based awards. Beginning in 2017, the total target grant date fair value of the stock compensation awards granted was comprised 20% each of EPS-based awards and ROE-based awards and 30% each of TSR-based awards and restricted stock units.

The fair value of TSR-based performance share unit awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's common stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three -year performance period without remeasurement.

The fair values of the EPS-based awards and the ROE-based awards are based on the closing stock price of Southern Company common stock on the date of the grant. Compensation expense for the EPS-based and ROE-based awards is generally recognized ratably over the three -year performance period initially assuming a 100% payout at the end of the performance period. Employees become immediately vested in the TSR-based performance share units, along with the EPS-based and ROE-based awards, upon retirement. As a result, compensation expense for employees that are retirement eligible at the grant date is recognized immediately while compensation expense for employees that become retirement eligible during the vesting period is recognized over the period from grant date to the date of retirement eligibility. The expected payout related to the EPS-based and ROE-based awards is reevaluated annually with expense recognized to date increased or decreased based on the number of shares currently expected to be issued. Unlike the TSR-based awards, the compensation expense ultimately recognized for the EPS-based awards and the ROE-based awards will be based on the actual number of shares issued at the end of the performance period.

For the years ended December 31, 2017 , 2016 , and 2015 , employees of the Company were granted performance share units of 28,423 , 57,333 , and 48,962 , respectively. The weighted average grant-date fair value of TSR-based performance share units granted during 2017 , 2016 , and 2015 , determined using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period, was $47.30 , $45.18 , and $46.38 , respectively. The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2017 , 2016 , and 2015 was $49.18 , $48.83 , and $47.75 , respectively.

For the years ended December 31, 2017 , 2016 , and 2015 , total compensation cost for performance share units recognized in income and the related tax benefit also recognized in income was immaterial. The compensation cost related to the grant of Southern Company performance share units to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2017 , total unrecognized compensation cost related to performance share award units was immaterial.

***Restricted Stock Units***

Beginning in 2017 , stock-based compensation granted to employees included restricted stock units in addition to performance share units. One-third of the restricted stock units granted to employees vest each year throughout a three -year service period. All unvested restricted stock units vest immediately upon a change in control where Southern Company is not the surviving corporation. Shares of Southern Company common stock are delivered to employees at the end of the vesting period.

The fair value of restricted stock units is based on the closing stock price of Southern Company common stock on the date of the grant. Since one-third of the restricted stock units vest each year throughout a three -year service period, compensation expense for restricted stock unit awards is generally recognized over the corresponding one-, two-, or three-year period. Employees become immediately vested in the restricted stock units upon retirement. As a result, compensation expense for employees that are retirement eligible at the grant date is recognized immediately while compensation expense for employees that become retirement eligible during the vesting period is recognized over the period from grant date to the date of retirement eligibility.

For the year ended December 31, 2017 , employees of the Company were granted 15,736 restricted stock units. The weighted average grant-date fair value of restricted stock units granted during 2017 was $48.88 .

For the year ended December 31, 2017 , total compensation cost and the related tax benefit for restricted stock units recognized in income was immaterial. As of December 31, 2017 , total unrecognized compensation cost related to restricted stock units was immaterial.

***Stock Options***

In 2015, Southern Company discontinued the granting of stock options. Stock options expire no later than 10 years after the grant date and the latest possible exercise will occur no later than November 2024.

The compensation cost related to the grant of Southern Company stock options to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. Compensation cost and related tax benefits recognized in the Company's financial statements were not material for any year presented. As of December 31, 2017 , all compensation cost related to stock option awards has been recognized.

The total intrinsic value of options exercised during the years ended December 31, 2017 , 2016 , and 2015 was $2 million , $3 million , and $2 million , respectively. No cash proceeds are received by the Company upon the exercise of stock options. The actual tax benefit realized by the Company for the tax deductions from stock option exercises were immaterial for all years presented. Prior to the adoption of ASU 2016-09 in 2016 , the excess tax benefits related to the exercise of stock options were recognized in the Company's financial statements with a credit to equity. Upon the adoption of ASU 2016-09, beginning in 2016, all tax benefits related to the exercise of stock options are recognized in income. As of December 31, 2017 , the aggregate intrinsic value for the options outstanding and exercisable was $3 million .

**9. FAIR VALUE MEASUREMENTS**

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 2017 , assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

| | Fair Value Measurements Using | | | |
|---|---|---|---|---|
| **As of December 31, 2017:** | **Quoted Prices in Active Markets for Identical Assets (Level 1)** | **Significant Other Observable Inputs (Level 2)** | **Significant Unobservable Inputs (Level 3)** | **Total** |
| | | *(in millions)* | | |
| Assets: | | | | |
| Cash equivalents | $ 21 | $ — | $ — | $ 21 |
| Liabilities: | | | | |
| Energy-related derivatives | $ — | $ 21 | $ — | $ 21 |

As of December 31, 2016 , assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

| | Fair Value Measurements Using | | | |
|---|---|---|---|---|
| **As of December 31, 2016:** | **Quoted Prices in Active Markets for Identical Assets (Level 1)** | **Significant Other Observable Inputs (Level 2)** | **Significant Unobservable Inputs (Level 3)** | **Total** |
| | | *(in millions)* | | |
| Assets: | | | | |
| Energy-related derivatives | $ — | $ 5 | $ — | $ 5 |
| Cash equivalents | 20 | — | — | 20 |
| Total | $ 20 | $ 5 | $ — | $ 25 |
| Liabilities: | | | | |
| Energy-related derivatives | $ — | $ 29 | $ — | $ 29 |

**Valuation Methodologies**

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard over-the-counter products that are valued using observable market data and assumptions commonly used by market participants. The fair value of interest rate derivatives reflect the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk, and occasionally, implied volatility of interest rate options. The interest rate derivatives are categorized as Level 2 under Fair Value Measurements as these inputs are based on observable data and valuations of similar instruments. See Note 10 for additional information on how these derivatives are used.

As of December 31, 2017 and 2016 , other financial instruments for which the carrying amount did not equal fair value were as follows:

| | Carrying Amount | Fair Value |
|---|---|---|
| | *(in millions)* | |
| Long-term debt: | | |
| **2017** | **$ 1,285** | **$ 1,334** |
| 2016 | $ 1,074 | $ 1,097 |

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates available to the Company.

## 10. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and may enter into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a net basis. See Note 9 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

### Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in energy-related commodity prices. The Company manages fuel-hedging programs, implemented per the guidelines of the Florida PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility. The Florida PSC approved a stipulation and agreement that prospectively imposed a moratorium on the Company's fuel-hedging program in October 2016 through December 31, 2017. In connection with the 2017 Rate Case Settlement Agreement, the Florida PSC extended the moratorium on the Company's fuel-hedging program until January 1, 2021. The moratorium does not have an impact on the recovery of existing hedges entered into under the previously-approved hedging program.

Energy-related derivative contracts are accounted for under one of three methods:

- *Regulatory Hedges* — Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery clause.
- *Cash Flow Hedges* — Gains and losses on energy-related derivatives designated as cash flow hedges (which are mainly used to hedge anticipated purchases and sales) are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* — Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

**NOTES (continued)**
**Gulf Power Company 2017 Annual Report**

At December 31, 2017 , the net volume of energy-related derivative contracts for natural gas positions totaled 22 million mmBtu for the Company, with the longest hedge date of 2020 over which it is hedging its exposure to the variability in future cash flows for forecasted transactions.

In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 3 million mmBtu for the Company.

### Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to earnings.

At December 31, 2017 , there were no interest rate derivatives outstanding.

The estimated pre-tax losses related to interest rate derivatives that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2018 are immaterial. The Company has deferred gains and losses that are expected to be amortized into earnings through 2026 .

### Derivative Financial Statement Presentation and Amounts

The Company enters into energy-related and interest rate derivative contracts that may contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Fair value amounts of derivative assets and liabilities on the balance sheets are presented net to the extent that there are netting arrangements or similar agreements with the counterparties.

At December 31, 2017 and 2016 , the fair value of energy-related derivatives was reflected on the balance sheets as follows:

| | **2017** | | 2016 | |
|---|---|---|---|---|
| **Derivative Category and Balance Sheet Location** | **Assets** | **Liabilities** | Assets | Liabilities |
| | | *(in millions)* | | |
| **Derivatives designated as hedging instruments for regulatory purposes** | | | | |
| Energy-related derivatives: | | | | |
| Other current assets/Other current liabilities | **$ —** | **$ 14** | $ 4 | $ 12 |
| Other deferred charges and assets/Other deferred credits and liabilities | **—** | **7** | 1 | 17 |
| **Total derivatives designated as hedging instruments for regulatory purposes** | **$ —** | **$ 21** | $ 5 | $ 29 |
| **Gross amounts recognized** | **$ —** | **$ 21** | $ 5 | $ 29 |
| **Gross amounts offset** | **$ —** | **$ —** | $ (4) | $ (4) |
| **Net amounts recognized on the Balance Sheets** | **$ —** | **$ 21** | $ 1 | $ 25 |

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2017 and 2016 .

**NOTES (continued)**
**Gulf Power Company 2017 Annual Report**

At December 31, 2017 and 2016 , the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivatives designated as regulatory hedging instruments and deferred were as follows:

| | Unrealized Losses | | | | | Unrealized Gains | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Derivative Category** | **Balance Sheet Location** | | **2017** | | 2016 | **Balance Sheet Location** | | **2017** | | 2016 |
| | | | *(in millions)* | | | | | *(in millions)* | | |
| Energy-related derivatives: (*) | Other regulatory assets, current | **$** | **(14)** | $ | (9) | Other regulatory liabilities, current | **$** | **—** | $ | 1 |
| | Other regulatory assets, deferred | | **(7)** | | (16) | Other regulatory liabilities, deferred | | **—** | | — |
| **Total energy-related derivative gains (losses)** | | **$** | **(21)** | $ | (25) | | **$** | **—** | $ | 1 |

(*) The unrealized gains and losses for derivative contracts subject to netting arrangements were presented net on the balance sheets.

For the years ended December 31, 2017 , 2016 , and 2015 , the pre-tax effects of energy-related derivatives and interest rate derivatives designated as cash flow hedging instruments on the statements of income were immaterial and there was no material ineffectiveness recorded in earnings for any period presented.

For the years ended December 31, 2017 , 2016 , and 2015 , the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of income were not material.

**Contingent Features**

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2017 , the Company had no collateral posted with its derivative counterparties to satisfy these arrangements.

At December 31, 2017 , the fair value of derivative liabilities with contingent features was immaterial. However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk related contingent features, at a rating below BBB- and /or Baa3, were $12 million , and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

## 11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2017 and 2016 is as follows:

| Quarter Ended | Operating Revenues | Operating Income | Net Income After Dividends on Preference Stock |
|---|---|---|---|
| | | *(in millions)* | |
| **March 2017** | **$ 350** | **$ 46** | **$ 18** |
| **June 2017** | **357** | **75** | **35** |
| **September 2017** | **437** | **115** | **63** |
| **December 2017** | **372** | **53** | **19** |
| | | | |
| March 2016 | $ 335 | $ 65 | $ 29 |
| June 2016 | 365 | 74 | 34 |
| September 2016 | 436 | 90 | 45 |
| December 2016 | 349 | 54 | 23 |

The Company's business is influenced by seasonal weather conditions.

**SELECTED FINANCIAL AND OPERATING DATA 2013 - 2017**
**Gulf Power Company 2017 Annual Report**

| | 2017 | 2016 | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|
| **Operating Revenues (in millions)** | **$ 1,516** | $ 1,485 | $ 1,483 | $ 1,590 | $ 1,440 |
| **Net Income After Dividends on Preference Stock (in millions)** | **$ 135** | $ 131 | $ 148 | $ 140 | $ 124 |
| **Cash Dividends on Common Stock (in millions)** | **$ 165** | $ 120 | $ 130 | $ 123 | $ 115 |
| **Return on Average Common Equity (percent)** | **9.22** | 9.52 | 11.11 | 11.02 | 10.30 |
| **Total Assets (in millions) [(a)(b)]** | **$ 4,797** | $ 4,822 | $ 4,920 | $ 4,697 | $ 4,321 |
| **Gross Property Additions (in millions)** | **$ 201** | $ 179 | $ 247 | $ 361 | $ 305 |
| **Capitalization (in millions):** | | | | | |
| Common stock equity | **$ 1,531** | $ 1,389 | $ 1,355 | $ 1,309 | $ 1,235 |
| Preference stock | **—** | 147 | 147 | 147 | 147 |
| Long-term debt [(a)] | **1,285** | 987 | 1,193 | 1,362 | 1,150 |
| Total (excluding amounts due within one year) | **$ 2,816** | $ 2,523 | $ 2,695 | $ 2,818 | $ 2,532 |
| **Capitalization Ratios (percent):** | | | | | |
| Common stock equity | **54.4** | 55.1 | 50.3 | 46.5 | 48.8 |
| Preference stock | **—** | 5.8 | 5.4 | 5.2 | 5.8 |
| Long-term debt [(a)] | **45.6** | 39.1 | 44.3 | 48.3 | 45.4 |
| Total (excluding amounts due within one year) | **100.0** | 100.0 | 100.0 | 100.0 | 100.0 |
| **Customers (year-end):** | | | | | |
| Residential | **404,273** | 398,501 | 393,149 | 388,292 | 383,980 |
| Commercial | **56,700** | 56,091 | 55,460 | 54,892 | 54,567 |
| Industrial | **255** | 254 | 248 | 260 | 260 |
| Other | **578** | 569 | 614 | 603 | 582 |
| Total | **461,806** | 455,415 | 449,471 | 444,047 | 439,389 |
| **Employees (year-end)** | **1,288** | 1,352 | 1,391 | 1,384 | 1,410 |

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $8 million and $8 million is reflected for years 2014 and 2013, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(b) A reclassification of deferred tax assets from Total Assets of $3 million and $8 million is reflected for years 2014 and 2013, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

**SELECTED FINANCIAL AND OPERATING DATA 2013 - 2017 (continued)**
**Gulf Power Company 2017 Annual Report**

| | 2017 | 2016 | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|
| **Operating Revenues (in millions):** | | | | | |
| Residential | **$ 720** | $ 714 | $ 698 | $ 700 | $ 632 |
| Commercial | **412** | 410 | 403 | 408 | 395 |
| Industrial | **144** | 152 | 144 | 153 | 139 |
| Other | **5** | 5 | 4 | 6 | 4 |
| Total retail | **1,281** | 1,281 | 1,249 | 1,267 | 1,170 |
| Wholesale — non-affiliates | **57** | 61 | 107 | 129 | 109 |
| Wholesale — affiliates | **108** | 75 | 58 | 130 | 100 |
| Total revenues from sales of electricity | **1,446** | 1,417 | 1,414 | 1,526 | 1,379 |
| Other revenues | **70** | 68 | 69 | 64 | 61 |
| Total | **$ 1,516** | $ 1,485 | $ 1,483 | $ 1,590 | $ 1,440 |
| **Kilowatt-Hour Sales (in millions):** | | | | | |
| Residential | **5,229** | 5,358 | 5,365 | 5,362 | 5,089 |
| Commercial | **3,814** | 3,869 | 3,898 | 3,838 | 3,810 |
| Industrial | **1,740** | 1,830 | 1,798 | 1,849 | 1,700 |
| Other | **26** | 25 | 25 | 26 | 21 |
| Total retail | **10,809** | 11,082 | 11,086 | 11,075 | 10,620 |
| Wholesale — non-affiliates | **749** | 751 | 1,040 | 1,670 | 1,163 |
| Wholesale — affiliates | **3,887** | 2,784 | 1,906 | 3,284 | 3,127 |
| Total | **15,445** | 14,617 | 14,032 | 16,029 | 14,910 |
| **Average Revenue Per Kilowatt-Hour (cents):** | | | | | |
| Residential | **13.77** | 13.33 | 13.01 | 13.06 | 12.43 |
| Commercial | **10.80** | 10.60 | 10.34 | 10.64 | 10.37 |
| Industrial | **8.28** | 8.31 | 8.01 | 8.28 | 8.15 |
| Total retail | **11.85** | 11.56 | 11.27 | 11.44 | 11.02 |
| Wholesale | **3.56** | 3.85 | 5.60 | 5.23 | 4.87 |
| Total sales | **9.36** | 9.69 | 10.08 | 9.52 | 9.25 |
| **Residential Average Annual** | | | | | |
| **Kilowatt-Hour Use Per Customer** | **13,015** | 13,515 | 13,705 | 13,865 | 13,301 |
| **Residential Average Annual** | | | | | |
| **Revenue Per Customer** | **$ 1,792** | $ 1,801 | $ 1,783 | $ 1,811 | $ 1,653 |
| **Plant Nameplate Capacity** | | | | | |
| **Ratings (year-end) (megawatts)** | **2,278** | 2,278 | 2,583 | 2,663 | 2,663 |
| **Maximum Peak-Hour Demand (megawatts):** | | | | | |
| Winter | **2,202** | 2,033 | 2,488 | 2,684 | 1,729 |
| Summer | **2,422** | 2,503 | 2,491 | 2,424 | 2,356 |
| **Annual Load Factor (percent)** | **55.2** | 54.7 | 54.9 | 51.1 | 55.9 |
| **Plant Availability Fossil-Steam (percent)** | **79.3** | 81.0 | 88.3 | 89.4 | 92.8 |
| **Source of Energy Supply (percent):** | | | | | |
| Coal | **33.1** | 31.0 | 33.5 | 44.5 | 36.4 |
| Gas | **27.8** | 23.2 | 25.6 | 22.2 | 23.0 |
| Purchased power — | | | | | |
| From non-affiliates | **35.6** | 41.1 | 30.4 | 28.9 | 37.0 |
| From affiliates | **3.5** | 4.7 | 10.5 | 4.4 | 3.6 |
| Total | **100.0** | 100.0 | 100.0 | 100.0 | 100.0 |

# MISSISSIPPI POWER COMPANY

# FINANCIAL SECTION

**MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING**
**Mississippi Power Company 2017 Annual Report**

The management of Mississippi Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2017 .

/s/ Anthony L. Wilson
Anthony L. Wilson
Chairman, President, and Chief Executive Officer

/s/ Moses H. Feagin
Moses H. Feagin
Vice President, Chief Financial Officer, and Treasurer

February 20, 2018

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the stockholders and the Board of Directors of Mississippi Power Company

**Opinion on the Financial Statements**

We have audited the accompanying balance sheets and statements of capitalization of Mississippi Power Company (the Company) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2017 and 2016 , the related statements of operations, comprehensive income (loss), common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2017 , and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements (pages II-431 to II-477 ) present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016 , and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017 , in conformity with accounting principles generally accepted in the United States of America.

**Basis for Opinion**

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 20, 2018

We have served as the Company's auditor since 2002.

**DEFINITIONS**

| **Term** | **Meaning** |
|---|---|
| 2012 MPSC CPCN Order | A detailed order issued by the Mississippi PSC in April 2012 confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing acquisition, construction, and operation of the Kemper County energy facility |
| AFUDC | Allowance for funds used during construction |
| Alabama Power | Alabama Power Company |
| ARO | Asset retirement obligation |
| ASC | Accounting Standards Codification |
| ASU | Accounting Standards Update |
| CCR | Coal combustion residuals |
| Clean Air Act | Clean Air Act Amendments of 1990 |
| $CO_2$ | Carbon dioxide |
| Cooperative Energy | Electric cooperative in Mississippi |
| CPCN | Certificate of public convenience and necessity |
| CWIP | Construction work in progress |
| DOE | U.S. Department of Energy |
| ECM | Energy cost management clause |
| ECO | Environmental compliance overview |
| EPA | U.S. Environmental Protection Agency |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| GAAP | U.S. generally accepted accounting principles |
| Georgia Power | Georgia Power Company |
| Gulf Power | Gulf Power Company |
| IGCC | Integrated coal gasification combined cycle, the technology originally approved for Mississippi Power's Kemper County energy facility (Plant Ratcliffe) |
| IRS | Internal Revenue Service |
| ITC | Investment tax credit |
| KWH | Kilowatt-hour |
| LIBOR | London Interbank Offered Rate |
| Mirror CWIP | A regulatory liability used by Mississippi Power to record financing costs associated with construction of the Kemper County energy facility, which were subsequently refunded to customers |
| mmBtu | Million British thermal units |
| Moody's | Moody's Investors Service, Inc. |
| MPUS | Mississippi Public Utilities Staff |
| MRA | Municipal and Rural Associations |
| MW | Megawatt |
| $NO_X$ | Nitrogen oxide |
| OCI | Other comprehensive income |
| PEP | Performance evaluation plan |
| power pool | The operating arrangement whereby the integrated generating resources of the traditional electric operating companies and Southern Power (excluding subsidiaries) are subject to joint commitment and dispatch in order to serve their combined load obligations |

**DEFINITIONS**
(continued)

| Term | Meaning |
|---|---|
| PPA | Power purchase agreement |
| PSC | Public Service Commission |
| ROE | Return on equity |
| S&P | S&P Global Ratings, a division of S&P Global Inc. |
| scrubber | Flue gas desulfurization system |
| SCS | Southern Company Services, Inc. (the Southern Company system service company) |
| SEC | U.S. Securities and Exchange Commission |
| $SO_2$ | Sulfur dioxide |
| Southern Company | The Southern Company |
| Southern Company Gas | Southern Company Gas and its subsidiaries |
| Southern Company system | Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), Southern Electric Generating Company, Southern Nuclear, SCS, Southern Linc, PowerSecure, Inc. (as of May 9, 2016), and other subsidiaries |
| Southern Linc | Southern Communications Services, Inc. |
| Southern Nuclear | Southern Nuclear Operating Company, Inc. |
| Southern Power | Southern Power Company and its subsidiaries |
| SRR | System Restoration Rider, a tariff for retail property damage reserve |
| Tax Reform Legislation | The Tax Cuts and Jobs Act, which was signed into law on December 22, 2017 and became effective on January 1, 2018 |
| traditional electric operating companies | Alabama Power, Georgia Power, Gulf Power, and Mississippi Power |

**MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS**
**Mississippi Power Company 2017 Annual Report**

## OVERVIEW

### Business Activities

Mississippi Power Company (the Company) operates as a vertically integrated utility providing electric service to retail customers within its traditional service territory located within the State of Mississippi and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of providing electric service. These factors include the Company's ability to maintain and grow energy sales and to operate in a constructive regulatory environment that provides timely recovery of prudently-incurred costs. These costs include those related to reliability, fuel, and stringent environmental standards, as well as ongoing capital and operations and maintenance expenditures and restoration following major storms. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

The Kemper County energy facility was approved by the Mississippi PSC as an IGCC facility in the 2010 CPCN proceedings, subject to a construction cost cap of $2.88 billion, net of $245 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (Initial DOE Grants) and excluding the cost of the lignite mine and equipment, the cost of the $CO_2$ pipeline facilities, AFUDC, and certain general exceptions (Cost Cap Exceptions). The combined cycle and associated common facilities portions of the Kemper County energy facility were placed in service in August 2014. In December 2015, the Mississippi PSC issued an order (In-Service Asset Rate Order), authorizing rates that provided for the recovery of approximately $126 million annually related to the assets previously placed in service.

On June 21, 2017, the Mississippi PSC stated its intent to issue an order (which occurred on July 6, 2017) directing the Company to pursue a settlement under which the Kemper County energy facility would be operated as a natural gas plant, rather than an IGCC plant, and address all issues associated with the Kemper County energy facility (Kemper Settlement Order). The Kemper Settlement Order established a new docket for the purposes of pursuing a global settlement of the related costs (Kemper Settlement Docket).

On June 28, 2017, the Company notified the Mississippi PSC that it would begin a process to suspend operations and start-up activities on the gasifier portion of the Kemper County energy facility, given the uncertainty as to its future. At the time of project suspension, the total cost estimate for the Kemper County energy facility was approximately $7.38 billion, including approximately $5.95 billion of costs subject to the construction cost cap, and was net of the $137 million in additional grants from the DOE received on April 8, 2016 (Additional DOE Grants). In the aggregate, the Company had incurred charges of $3.07 billion ($1.89 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through May 31, 2017. Given the Mississippi PSC's stated intent regarding no further rate increase for the Kemper County energy facility and the subsequent suspension, cost recovery of the gasifier portions became no longer probable; therefore, the Company recorded an additional charge to income in June 2017 of $2.8 billion ($2.0 billion after tax), which included estimated costs associated with the gasifier portions of the plant and lignite mine.

On February 6, 2018, the Mississippi PSC voted to approve a settlement agreement related to cost recovery for the Kemper County energy facility among the Company, the MPUS, and certain intervenors (Kemper Settlement Agreement). The Kemper Settlement Agreement provides for an annual revenue requirement of approximately $99.3 million for costs related to the Kemper County energy facility, which includes the impact of Tax Reform Legislation. The revenue requirement is based on (i) a fixed ROE for 2018 of 8.6%, excluding any performance adjustment, (ii) a ROE for 2019 calculated in accordance with PEP, excluding the performance adjustment, (iii) for future years, a performance-based ROE calculated pursuant to PEP, and (iv) amortization periods for the related regulatory assets and liabilities of eight years and six years, respectively. The revenue requirement also reflects a disallowance related to a portion of the Company's investment in the Kemper County energy facility requested for inclusion in rate base, which was recorded in the fourth quarter 2017 as an additional charge to income of approximately $78 million ($85 million net of accumulated depreciation of $7 million) pre-tax ($48 million after tax).

Under the Kemper Settlement Agreement, retail customer rates will reflect a reduction of approximately $26.8 million annually and include no recovery for costs associated with the gasifier portion of the Kemper County energy facility in 2018 or at any future date. On February 12, 2018, the Company made the required compliance filing with the Mississippi PSC. The Kemper Settlement Agreement also requires (i) the CPCN for the Kemper County energy facility to be modified to limit it to natural gas combined cycle operation and (ii) the Company to file a reserve margin plan with the Mississippi PSC by August 2018.

During the third and fourth quarters of 2017, the Company recorded charges to income of $242 million ($206 million after tax), including $164 million for ongoing project costs, estimated mine and gasifier-related costs, and certain termination costs during the suspension period prior to conclusion of the Kemper Settlement Docket, as well as the charge associated with the Kemper Settlement Agreement. Additional pre-tax cancellation costs, including mine and plant closure and contract termination costs, currently estimated at approximately $50 million to $100 million (excluding salvage), are expected to be incurred in 2018. The Company has begun efforts to dispose of or abandon the mine and gasifier-related assets.

Total pre-tax charges to income related to the Kemper County energy facility were $3.4 billion ($2.4 billion after tax) for the year ended December 31, 2017. In the aggregate, since the Kemper County energy facility project started, the Company has incurred charges of $6.2 billion ($4.1 billion after tax) through December 31, 2017.

As a result of the Mississippi PSC order on February 6, 2018, rate recovery for the Kemper County energy facility is resolved, subject to any future legal challenges.

For additional information, see FUTURE EARNINGS POTENTIAL – "Kemper County Energy Facility" and "Other Matters" herein.

The Company's financial statement presentation contemplates continuation of the Company as a going concern as a result of Southern Company's anticipated ongoing financial support of the Company. For additional information, see Note 6 to the financial statements under "Going Concern." In June 2017, Southern Company made equity contributions totaling $1.0 billion to the Company. The Company used a portion of the proceeds to (i) prepay $300 million of the outstanding principal amount under its $1.2 billion unsecured term loan; (ii) repay $591 million of the outstanding principal amount of promissory notes to Southern Company; and (iii) repay $10 million of the outstanding principal amount of bank loans.

As of December 31, 2017, the Company's current liabilities exceeded current assets by approximately $911 million primarily due to a $900 million unsecured term loan that matures on March 31, 2018. The Company expects to refinance the unsecured term loan with external security issuances and/or borrowings from financial institutions or Southern Company. To fund the Company's capital needs over the next 12 months, the Company intends to utilize operating cash flows, external security issuances, lines of credit, bank term loans, equity contributions from Southern Company, and, to the extent necessary, loans from Southern Company.

The Company continues to focus on several key performance indicators. In recognition that the Company's long-term financial success is dependent upon how well it satisfies its customers' needs, the Company's retail base rate mechanism, PEP, includes performance indicators that directly tie customer service indicators to the Company's allowed ROE. PEP measures the Company's performance on a 10-point scale as a weighted average of results in three areas: average customer price, as compared to prices of other regional utilities (weighted at 40%); service reliability, measured in percentage of time customers had electric service (40%); and customer satisfaction, measured in a survey of residential customers (20%). The Company also focuses on broader measures of customer satisfaction, plant availability, system reliability, and net income after dividends on preferred stock.

On January 16, 2018, the Mississippi PSC approved the 2018 retail fuel cost recovery factor, effective February 2018 through January 2019, which resulted in a $39 million increase in annual revenues. On February 7, 2018, the Company filed its 2018 PEP forecast, requesting an increase in annual base revenues of $26 million. On February 14, 2018, the Company submitted its 2018 ECO filing, requesting an increase in annual retail revenue of $17 million. The PEP and ECO filings include the effects of Tax Reform Legislation. Rulings from the Mississippi PSC on the PEP and ECO filings are expected in the first half of 2018. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" for more information. The ultimate outcome of this matter cannot be determined at this time.

The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys to evaluate the Company's results and generally targets top-quartile performance.

See RESULTS OF OPERATIONS herein for information on the Company's financial performance.

**Earnings**

The Company's net loss after dividends on preferred stock was $2.59 billion in 2017 compared to a $50 million net loss in 2016 . The change in 2017 was primarily the result of higher pre-tax charges of $3.36 billion ($2.39 billion after tax) in 2017 compared to pre-tax charges of $428 million ($264 million after tax) in 2016 for estimated losses on the Kemper IGCC.

The Company's net loss after dividends on preferred stock was $50 million in 2016 compared to $8 million in 2015 . The change in 2016 was primarily the result of higher pre-tax charges of $428 million ($264 million after tax) in 2016 compared to pre-tax charges of $365 million ($226 million after tax) in 2015 for estimated losses on the Kemper IGCC. The decrease in net income was partially offset by an increase in retail revenues due to the implementation of rates in September 2015 for certain Kemper

County energy facility in-service assets, partially offset by a decrease in wholesale revenues. The increase in revenues was partially offset by an increase in interest expense in 2016 compared to 2015 due to the termination of an asset purchase agreement between the Company and Cooperative Energy in 2015 and an increase in operations and maintenance expenses.

See Note 3 to the financial statements under "Kemper County Energy Facility" for additional information.

**RESULTS OF OPERATIONS**

A condensed statement of operations follows:

| | **Amount** | **Increase (Decrease) from Prior Year** | |
|---|---|---|---|
| | **2017** | **2017** | 2016 |
| | | *(in millions)* | |
| Operating revenues | **$ 1,187** | **$ 24** | $ 25 |
| Fuel | **395** | **52** | (100) |
| Purchased power | **25** | **(9)** | 22 |
| Other operations and maintenance | **282** | **(30)** | 38 |
| Depreciation and amortization | **161** | **29** | 9 |
| Taxes other than income taxes | **104** | **(5)** | 15 |
| Estimated loss on Kemper IGCC | **3,362** | **2,934** | 63 |
| Total operating expenses | **4,329** | **2,971** | 47 |
| Operating loss | **(3,142)** | **(2,947)** | (22) |
| Allowance for equity funds used during construction | **72** | **(52)** | 14 |
| Interest expense, net of amounts capitalized | **42** | **(32)** | 67 |
| Other income (expense), net | **(8)** | **(1)** | 1 |
| Income taxes (benefit) | **(532)** | **(428)** | (32) |
| Net income (loss) | **(2,588)** | **(2,540)** | (42) |
| Dividends on preferred stock | **2** | **—** | — |
| Net loss after dividends on preferred stock | **$ (2,590)** | **$ (2,540)** | $ (42) |

**Operating Revenues**

Operating revenues for 2017 were $1.2 billion , reflecting a $24 million increase from 2016 . Details of operating revenues were as follows:

| | Amount | |
|---|---|---|
| | **2017** | 2016 |
| | *(in millions)* | |
| Retail — prior year | **$ 859** | $ 776 |
| Estimated change resulting from — | | |
| Rates and pricing | **(7)** | 96 |
| Sales growth (decline) | **4** | (4) |
| Weather | **(15)** | 8 |
| Fuel and other cost recovery | **13** | (17) |
| Retail — current year | **854** | 859 |
| Wholesale revenues — | | |
| Non-affiliates | **259** | 261 |
| Affiliates | **56** | 26 |
| Total wholesale revenues | **315** | 287 |
| Other operating revenues | **18** | 17 |
| Total operating revenues | **$ 1,187** | $ 1,163 |
| Percent change | **2.1%** | 2.2% |

Total retail revenues for 2017 decreased $5 million , or 0.6% , compared to 2016 primarily due to a $15 million decrease as a result of milder weather in 2017 and the deferral of $17 million of revenue following the complete amortization of certain regulatory assets related to the Kemper County energy facility in July 2017. These decreases were partially offset by a $10 million net increase related to ECO plan rate changes in the third quarter 2016 and the second quarter 2017 and an increase of $13 million in fuel cost recovery. Total retail revenues for 2016 increased $83 million, or 10.7%, compared to 2015 primarily due to changes in rates and pricing of $96 million, partially offset by a net decrease in fuel and other cost recovery of $17 million.

See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Compliance Overview" and "Kemper County Energy Facility – Rate Recovery" for additional information. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales and weather.

Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the energy component of purchased power costs, and do not affect net income. Recoverable fuel costs include fuel and purchased power expenses reduced by the fuel and emissions portion of wholesale revenues from energy sold to customers outside the Company's service territory. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" herein for additional information.

Wholesale revenues from power sales to non-affiliated utilities, including FERC-regulated MRA sales as well as market-based sales, were as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| Capacity and other | **$ 154** | $ 157 | $ 158 |
| Energy | **105** | 104 | 112 |
| Total non-affiliated | **$ 259** | $ 261 | $ 270 |

Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. In addition, the Company provides service under long-term contracts with rural electric cooperative associations and municipalities located in southeastern Mississippi under cost-based electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represented 19.3% of the Company's total operating revenues in 2017 and are largely subject to rolling 10-year cancellation notices. Historically, these wholesale customers have acted as a group and any changes in contractual relationships for one customer are likely to be followed by the other wholesale customers.

Short-term opportunity energy sales are also included in sales for resale to non-affiliates. These opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost to produce the energy.

Wholesale revenues from sales to affiliates will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost.

Wholesale revenues from sales to affiliates increased $30 million, or 115.4%, in 2017 compared to 2016 . The increase was primarily due to higher natural gas prices and higher KWH sales due to dispatch of the Company's lower cost generation resources to serve system territorial load. Wholesale revenues from sales to affiliates decreased $50 million, or 65.8%, in 2016 compared to 2015 primarily due to a $50 million decrease in energy revenues of which $4 million was associated with lower fuel prices and $46 million was associated with a decrease in KWH sales as a result of lower cost generation available in the Southern Company system.

*Energy Sales*

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2017 and the percent change from the prior year were as follows:

| | Total KWHs | Total KWH Percent Change | | Weather-Adjusted Percent Change | |
|---|---|---|---|---|---|
| | **2017** | **2017** | 2016 | **2017** | 2016 |
| | *(in millions)* | | | | |
| Residential | **1,944** | **(5.2)%** | 1.3 % | **1.4 %** | (2.4)% |
| Commercial | **2,764** | **(2.7)** | 1.3 | **(0.1)** | (2.2) |
| Industrial | **4,841** | **(1.3)** | (1.0) | **(1.3)** | (1.6) |
| Other | **39** | **(1.6)** | (1.3) | **(1.6)** | (1.3) |
| Total retail | **9,588** | **(2.5)** | 0.1 | **(0.4)%** | (1.9)% |
| Wholesale | | | | | |
| Non-affiliated | **3,672** | **(6.3)** | 1.7 | | |
| Affiliated | **2,024** | **82.7** | (60.5) | | |
| Total wholesale | **5,696** | **14.0** | (24.5) | | |
| Total energy sales | **15,284** | **2.8 %** | (9.8)% | | |

Changes in retail energy sales are generally the result of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales decreased 2.5% in 2017 as compared to the prior year. This decrease was primarily the result of milder weather in 2017 as compared to 2016 . Weather-adjusted residential KWH sales increased in 2017 primarily due to increased customer usage. Weather-adjusted commercial KWH sales decreased primarily due to decreased customer usage largely offset by customer growth. The decrease in industrial KWH energy sales was primarily due to Hurricane Nate, which impacted several large industrial customers.

Retail energy sales increased 0.1% in 2016 as compared to the prior year. This increase was primarily the result of warmer weather in the third quarter 2016 as compared to the corresponding period in 2015. Weather-adjusted residential and commercial KWH sales decreased primarily due to decreased customer usage partially offset by customer growth. The decrease in industrial KWH energy sales was primarily due to planned and unplanned outages by large industrial customers.

See "Operating Revenues" above for a discussion of significant changes in wholesale revenues to affiliated companies.

***Fuel and Purchased Power Expenses***

Fuel costs constitute one of the largest expenses for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

Details of the Company's generation and purchased power were as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| Total generation *(in millions of KWHs)* | **15,319** | 14,514 | 17,014 |
| Total purchased power *(in millions of KWHs)* | **1,314** | 1,574 | 539 |
| Sources of generation *(percent)* – | | | |
| Gas | **92** | 91 | 83 |
| Coal | **8** | 9 | 17 |
| Cost of fuel, generated *(in cents per net KWH)* – | | | |
| Gas | **2.69** | 2.41 | 2.58 |
| Coal | **3.64** | 3.91 | 3.71 |
| Average cost of fuel, generated *(in cents per net KWH)* | **2.77** | 2.55 | 2.78 |
| Average cost of purchased power *(in cents per net KWH)* | **3.50** | 3.07 | 2.17 |

Fuel and purchased power expenses were $420 million in 2017 , an increase of $43 million, or 11.4%, as compared to the prior year. The increase was primarily due to a $36 million increase in the average cost of generation and purchased power and a net increase of $7 million in KWHs generated from gas generation.

Fuel and purchased power expenses were $377 million in 2016, a decrease of $78 million, or 17.1%, as compared to the prior year. The decrease was primarily due to a decrease of $70 million in the volume of KWHs generated and purchased and an $8 million increase in the average cost of generation and purchased power.

Fuel and purchased power energy transactions do not have a significant impact on earnings, since energy expenses are generally offset by energy revenues through the Company's fuel cost recovery clauses. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" herein and Note 1 to the financial statements under "Fuel Costs" for additional information.

*Fuel*

Fuel expense increased $52 million , or 15.2% , in 2017 compared to 2016 primarily due to an 11.6% higher cost of natural gas. Fuel expense decreased $100 million, or 22.6%, in 2016 compared to 2015 due to an 8.2% decrease in the average cost of fuel per KWH generated and a 15.5% decrease in the volume of KWHs generated.

*Purchased Power*

Purchased power expense decreased $9 million , or 26.5% , in 2017 compared to 2016 . The decrease was primarily the result of a 16.5% decrease in the volume of KWHs purchased offset by a slight increase in the average cost per KWH purchased compared to 2016. Purchased power expense increased $22 million, or 183.3%, in 2016 compared to 2015. The increase in 2016 was primarily the result of a 192.1% increase in the volume of KWHs purchased due to the availability of lower cost energy as compared to the cost of self-generation.

Energy purchases will vary depending on the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. These purchases are made in accordance with the IIC or other contractual agreements, as approved by the FERC.

***Other Operations and Maintenance Expenses***

Other operations and maintenance expenses decreased $30 million , or 9.6% , in 2017 compared to the prior year. The decrease was primarily due to a $10 million decrease in transmission and distribution expenses related to overhead line maintenance, an $8 million decrease in contractor services related to facilities, corporate advertising, and employee compensation and benefits, and an $8 million decrease related to the combined cycle and the associated common facilities portion of the Kemper County energy facility.

Other operations and maintenance expenses increased $38 million, or 13.9%, in 2016 compared to the prior year. The increase was primarily due to increases of $28 million related to the combined cycle and associated common facilities portion of the Kemper County energy facility and $10 million in amortization of prior expense deferrals, both following the In-Service Asset Rate Order in December 2015, as well as a $7 million increase in transmission and distribution expenses primarily related to overhead line maintenance and vegetation management expenses, partially offset by a $9 million decrease in planned generation outage costs.

***Depreciation and Amortization***

Depreciation and amortization increased $29 million , or 22.0% , in 2017 compared to 2016 primarily due to $13 million of amortization related to the ECO plan, $7 million of depreciation for additional plant in service, and $6 million in additional regulatory asset amortization associated with the Mercury and Air Toxics Standards (MATS) rule compliance.

Depreciation and amortization increased $9 million, or 7.3%, in 2016 compared to 2015 primarily due to $32 million of additional regulatory asset amortization related to the In-Service Asset Rate Order, ECO plan, and MATS rule compliance, $13 million associated with Kemper County energy facility deferrals primarily related to depreciation deferrals in 2015, and $9 million of depreciation for additional plant in service assets primarily associated with the Plant Daniel scrubbers. These increases were partially offset by $23 million of regulatory deferrals related to the In-Service Asset Rate Order and a $22 million deferral associated with the implementation of revised ECO plan rates with the first billing cycle for September 2016.

See Note 1 to the financial statements under "Depreciation and Amortization" and Note 3 to the financial statements under "FERC Matters" and "Retail Regulatory Matters – Environmental Compliance Overview Plan" for additional information.

***Taxes Other Than Income Taxes***

Taxes other than income taxes decreased $5 million , or 4.6% , in 2017 compared to 2016 primarily due to a decrease in franchise taxes of $4 million, as well as a decrease in ad valorem taxes of $1 million. Taxes other than income taxes increased $15 million, or 16.0%, in 2016 compared to 2015 primarily due to increases in ad valorem taxes of $10 million, related to an increase in the assessed value of property, as well as increases in franchise taxes of $5 million, related to increased operating revenue.

The retail portion of ad valorem taxes is recoverable under the Company's ad valorem tax cost recovery clause and, therefore, does not affect net income.

***Estimated Loss on Kemper IGCC***

In 2017 , 2016 , and 2015, estimated probable losses on the Kemper IGCC of $3.36 billion , $428 million, and $365 million, respectively, were recorded. On June 28, 2017, the Company suspended the gasifier portion of the project and recorded a charge to earnings for the remaining $2.8 billion book value of the gasifier portion of the project. Prior to the suspension, the Company recorded losses for revisions of estimated costs expected to be incurred on construction of the Kemper IGCC in excess of the $2.88 billion cost cap established by the Mississippi PSC, net of $245 million of the Initial DOE Grants and excluding the Cost Cap Exceptions.

See Note 3 to the financial statements under "Kemper County Energy Facility" for additional information.

***Allowance for Equity Funds Used During Construction***

AFUDC equity decreased $52 million , or 41.9% , in 2017 as compared to 2016 as a result of the Kemper IGCC project suspension in June 2017. AFUDC equity increased $14 million, or 12.7%, in 2016 as compared to 2015 primarily due to a higher AFUDC rate and an increase in Kemper County energy facility CWIP subject to AFUDC prior to the suspension of the gasifier portion of the project, partially offset by placing the Plant Daniel scrubbers in service in November 2015. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Allowance for Funds Used During Construction" herein and Note 3 to the financial statements under "Kemper County Energy Facility" for additional information.

***Interest Expense, Net of Amounts Capitalized***

Interest expense, net of amounts capitalized decreased $32 million in 2017 compared to 2016 . The decrease was primarily associated with a $36 million net reduction in interest following a settlement with the IRS related to research and experimental (R&E) deductions. Also contributing to the decrease was the amortization of $6 million in interest deferrals in accordance with the In-Service Asset Rate Order and a $7 million decrease in interest related to outstanding debt as a result of lower balances and lower rates. These decreases were partially offset by a $20 million reduction in interest capitalized following suspension of the Kemper County energy facility construction.

See Note 5 to the financial statements under "Section 174 Research and Experimental Deduction" for additional information.

Interest expense, net of amounts capitalized increased $67 million in 2016 compared to 2015. The increase was primarily due to an increase of $31 million of interest on deposits resulting from the 2015 reversal of interest associated with the termination of an asset purchase agreement between the Company and Cooperative Energy in May 2015; a $20 million increase due to additional long-term debt and a $30 million decrease in amounts capitalized primarily resulting from $17 million of capitalized interest and the amortization of $13 million in interest deferrals in accordance with the In-Service Asset Rate Order. These net increases were partially offset by a decrease of $16 million in interest accrued on the Mirror CWIP liability prior to refund in 2015.

***Income Taxes (Benefit)***

Income tax benefits increased $428 million , or 411.5% , in 2017 compared to 2016 primarily due to $809 million in tax benefits on the estimated probable losses on the Kemper IGCC, net of the non-deductible AFUDC equity portion and the related state valuation allowances, partially offset by $372 million resulting from Tax Reform Legislation. Tax Reform Legislation earnings impacts are primarily due to revaluing deferred tax assets related to the Kemper County energy facility. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters" herein and Note 5 to the financial statements for additional information.

Income tax benefits increased $32 million, or 44.4%, in 2016 compared to 2015 primarily as a result of an increase in the estimated probable losses on the Kemper IGCC and an increase in AFUDC equity, which is non-taxable.

**Effects of Inflation**

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

**FUTURE EARNINGS POTENTIAL**

**General**

The Company operates as a vertically integrated utility providing electric service to retail customers within its traditional service territory located in southeast Mississippi and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Mississippi PSC under cost-based regulatory principles. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. See "FERC Matters" herein, ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Utility Regulation" herein, and Note 3 to the financial statements for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of providing electric service. These factors include the Company's ability to recover its prudently-incurred costs, in a timely manner during a time of increasing costs, and its ability to prevail against legal challenges associated with the Kemper County energy facility. Future earnings will be driven primarily by customer growth. Earnings will also depend upon maintaining and growing sales, considering, among other things, the adoption and/or penetration rates of increasingly energy-efficient technologies and increasing volumes of electronic commerce transactions, both of which could contribute to a net reduction in customer usage. Earnings are subject to a variety of other factors. These factors include weather, competition, developing new and maintaining existing energy contracts and associated load requirements with other utilities and other wholesale customers, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territory. Demand for electricity is primarily driven by the pace of economic growth that may be affected by changes in regional and global economic conditions, which may impact future earnings.

The Company's retail base rates are set under the PEP, a rate plan approved by the Mississippi PSC. Two filings are made for each calendar year: the PEP projected filing, which is typically filed prior to the beginning of the year based on a projected revenue requirement, and the PEP lookback filing, which is filed after the end of the year and allows for review of the actual return compared to the allowed return range. See "Retail Regulatory Matters" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" for more information.

On October 4, 2017, the Company executed agreements with its largest retail customer, Chevron Products Company (Chevron), to continue providing retail service to the Chevron refinery in Pascagoula, Mississippi through 2038, subject to the approval of the Mississippi PSC. The new agreements are not expected to have a material impact on the Company's earnings; however, the co-generation assets located at the refinery are expected to be accounted for as a sales-type lease in accordance with the new lease accounting rules that become effective in 2019. These assets are also subject to a security interest granted to Chevron. See

FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein for additional information. The ultimate outcome of this matter cannot be determined at this time.

On December 22, 2017, Tax Reform Legislation was signed into law and became effective on January 1, 2018, which among other things, reduces the federal corporate income tax rate to 21% and changes rates of depreciation and the business interest deduction. See " Income Tax Matters – Federal Tax Reform Legislation " and FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein and Notes 3 and 5 to the financial statements for additional information.

The Company provides service under long-term contracts with rural electric cooperative associations and municipalities located in southeastern Mississippi under cost-based electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represented 19.3% of the Company's total operating revenues in 2017 and are largely subject to rolling 10-year cancellation notices. Historically, these wholesale customers have acted as a group and any changes in contractual relationships for one customer are likely to be followed by the other wholesale customers.

**Environmental Matters**

The Company's operations are regulated by state and federal environmental agencies through a variety of laws and regulations governing air, water, land, and protection of other natural resources. The Company maintains a comprehensive environmental compliance strategy to assess upcoming requirements and compliance costs associated with these environmental laws and regulations. The costs, including capital expenditures and operations and maintenance costs, required to comply with environmental laws and regulations may impact future unit retirement and replacement decisions, results of operations, cash flows, and financial condition. Compliance costs may result from the installation of additional environmental controls, closure and monitoring of CCR facilities, unit retirements, and adding or changing fuel sources for certain existing units, as well as related upgrades to the transmission system. A major portion of these compliance costs are expected to be recovered through existing ratemaking provisions. The ultimate impact of the environmental laws and regulations discussed below will depend on various factors, such as state adoption and implementation of requirements, the availability and cost of any deployed control technology, and the outcome of pending and/or future legal challenges.

New or revised environmental laws and regulations could affect many areas of the Company's operations. The impact of any such changes cannot be determined at this time. Environmental compliance costs could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis or through long-term wholesale agreements . Further, increased costs that are recovered through regulated rates could contribute to reduced demand for electricity , which could negatively affect results of operations, cash flows, and financial condition. Additionally, many commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity . See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Compliance Overview Plan" for additional information.

Through 2017 , the Company has invested approximately $643 million in environmental capital retrofit projects to comply with environmental requirements, with annual totals of approximately $9 million, $17 million, and $94 million for 2017 , 2016 , and 2015 , respectively. Although the timing, requirements, and estimated costs could change as environmental laws and regulations are adopted or modified, as compliance plans are revised or updated, and as legal challenges to rules are initiated or completed, the Company's current compliance strategy estimates capital expenditures of $63 million from 2018 through 2022 , with annual totals of approximately $14 million, $16 million, $17 million, $13 million, and $3 million for 2018 , 2019 , 2020 , 2021 , and 2022 , respectively. These estimates do not include any potential compliance costs associated with the regulation of $CO_2$ emissions from fossil fuel-fired electric generating units. See "Global Climate Issues" herein for additional information. The Company also anticipates expenditures associated with ash pond closure and ground water monitoring under the Disposal of Coal Combustion Residuals from Electric Utilities rule (CCR Rule), which are reflected in the Company's ARO liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

***Environmental Laws and Regulations***

*Air Quality*

The EPA has set National Ambient Air Quality Standards (NAAQS) for six air pollutants (carbon monoxide, lead, nitrogen dioxide, ozone, particulate matter, and $SO_2$ ), which it reviews and revises periodically. Revisions to these standards can require additional emission controls, improvements in control efficiency, or fuel changes which can result in increased compliance and operational costs. NAAQS requirements can also adversely affect the siting of new facilities. In 2015, the EPA published a more stringent eight-hour ozone NAAQS. The EPA plans to complete designations for this rule by no later than April 30, 2018 . No areas within the Company's service territory have been or are anticipated to be designated nonattainment under the 2015 ozone

NAAQS. In 2010, the EPA revised the NAAQS for $SO_2$, establishing a new one-hour standard, and is completing designations in multiple phases. The EPA has issued several rounds of area designations and no areas in the vicinity of Company -owned $SO_2$ sources have been designated nonattainment under the 2010 one-hour $SO_2$ NAAQS. However, final eight-hour ozone and $SO_2$ one-hour designations for certain areas are still pending and, if other areas are designated as nonattainment in the future, increased compliance costs could result.

In 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) and its $NO_X$ annual, $NO_X$ seasonal, and $SO_2$ annual programs. CSAPR is an emissions trading program that addresses the impacts of the interstate transport of $SO_2$ and $NO_X$ emissions from fossil fuel-fired power plants located in upwind states in the eastern half of the U.S. on air quality in downwind states. The Company has fossil fuel-fired generation subject to these requirements. In October 2016, the EPA published a final rule that revised the CSAPR seasonal $NO_X$ program, establishing more stringent $NO_X$ emissions budgets in Alabama and Mississippi . The outcome of ongoing CSAPR litigation, to which the Company is a party, could have an impact on the State of Mississippi's allowance allocations under the CSAPR seasonal $NO_X$ program. Increases in either future fossil fuel-fired generation or the cost of CSAPR allowances could have a negative financial impact on results of operations for the Company .

The EPA finalized regional haze regulations in 2005 and 2017. These regulations require states, tribal governments, and various federal agencies to develop and implement plans to reduce pollutants that impair visibility and demonstrate reasonable progress toward the goal of restoring natural visibility conditions in certain areas, including national parks and wilderness areas. States must submit a revised state implementation plan (SIP) to the EPA by July 31, 2021, demonstrating reasonable progress towards achieving visibility improvement goals. State implementation of reasonable progress could require further reductions in $SO_2$ or $NO_X$ emissions, which could result in increased compliance costs.

In 2015, the EPA published a final rule requiring certain states (including Alabama and Mississippi ) to revise or remove the provisions of their SIPs regulating excess emissions at industrial facilities, including electric generating facilities, during periods of startup, shut-down, or malfunction (SSM). The state excess emission rules provide necessary operational flexibility to affected units during periods of SSM and, if removed, could affect unit availability and result in increased operations and maintenance costs for the Company . The EPA has not yet responded to the SIP revisions proposed by states where the Company's generating units are located.

*Water Quality*

In 2014, the EPA finalized requirements under Section 316(b) of the Clean Water Act (CWA) to regulate cooling water intake structures at existing power plants and manufacturing facilities in order to minimize their effects on fish and other aquatic life. The regulation requires plant-specific studies to determine applicable measures to protect organisms that either get caught on the intake screens (impingement) or are drawn into the cooling system (entrainment). The ultimate impact of this rule will depend on the outcome of these plant-specific studies and any additional protective measures required to be incorporated into each plant's National Pollutant Discharge Elimination System (NPDES) permit based on site-specific factors.

In 2015, the EPA finalized the steam electric effluent limitations guidelines (ELG) rule that set national standards for wastewater discharges from steam electric generating units. The rule prohibits effluent discharges of certain wastestreams and imposes stringent arsenic, mercury, selenium, and nitrate/nitrite limits on scrubber wastewater discharges. The revised technology-based limits and compliance dates may require extensive modifications to existing ash and wastewater management systems or the installation and operation of new ash and wastewater management systems. Compliance with the ELG rule is expected to require capital expenditures and increased operational costs primarily affecting the Company's coal-fired electric generation. Compliance applicability dates range from November 1, 2018 to December 31, 2023 with state environmental agencies incorporating specific applicability dates in the NPDES permitting process based on information provided for each waste stream. The EPA has committed to a new rulemaking that could potentially revise the limitations and applicability dates of the ELG rule. The EPA expects to finalize this rulemaking in 2020.

In 2015, the EPA and the U.S. Army Corps of Engineers (Corps) jointly published a final rule that revised the regulatory definition of waters of the United States (WOTUS) for all CWA programs. The rule significantly expanded the scope of federal jurisdiction over waterbodies (such as rivers, streams, and canals), which could impact new generation projects and permitting and reporting requirements associated with the installation, expansion, and maintenance of transmission and distribution projects. On July 27, 2017, the EPA and the Corps proposed to rescind the 2015 WOTUS rule. The WOTUS rule has been stayed by the U.S. Court of Appeals for the Sixth Circuit since late 2015, but on January 22, 2018, the U.S. Supreme Court determined that federal district courts have jurisdiction over the pending challenges to the rule. On February 6, 2018, the EPA and the Corps published a final rule delaying implementation of the 2015 WOTUS rule to 2020.

*Coal Combustion Residuals*

In 2015, the EPA finalized non-hazardous solid waste regulations for the disposal of CCR, including coal ash and gypsum, in landfills and surface impoundments (CCR units) at active generating power plants. The CCR Rule requires CCR units to be evaluated against a set of performance criteria and potentially closed if minimum criteria are not met. Closure of existing CCR units could require installation of equipment and infrastructure to manage CCR in accordance with the rule. The EPA has announced plans to reconsider certain portions of the CCR Rule by no later than December 2019, which could result in changes to deadlines and corrective action requirements.

The EPA's reconsideration of the CCR Rule is due in part to a legislative development that impacts the potential oversight role of state agencies. Under the Water Infrastructure Improvements for the Nation Act, which became law in 2016, states are allowed to establish permit programs for implementing the CCR Rule.

Based on cost estimates for closure and monitoring of ash ponds pursuant to the CCR Rule, the Company recorded AROs for each CCR unit in 2015. As further analysis is performed and closure details are developed, the Company will continue to periodically update these cost estimates as necessary. In December 2016, the Mississippi PSC granted a CPCN to the Company authorizing certain projects associated with complying with the CCR Rule. Additionally in this order, the Mississippi PSC also authorized the Company to recover any costs associated with the CPCN, including future monitoring costs, through the ECO clause. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information regarding the Company's AROs as of December 31, 2017 .

*Environmental Remediation*

The Company must comply with environmental laws and regulations governing the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up affected sites. The Company has authority from the Mississippi PSC to recover approved environmental compliance costs through established regulatory mechanisms. The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable and reasonably estimable.

***Global Climate Issues***

In 2015, the EPA published final rules limiting $CO_2$ emissions from new, modified, and reconstructed fossil fuel-fired electric generating units and guidelines for states to develop plans to meet EPA-mandated $CO_2$ emission performance standards for existing units (known as the Clean Power Plan or CPP). In February 2016, the U.S. Supreme Court granted a stay of the CPP, which will remain in effect through the resolution of litigation in the U.S. Court of Appeals for the District of Columbia challenging the legality of the CPP and any review by the U.S. Supreme Court. On March 28, 2017, the U.S. President signed an executive order directing agencies to review actions that potentially burden the development or use of domestically produced energy resources, including review of the CPP and other $CO_2$ emissions rules. On October 10, 2017, the EPA published a proposed rule to repeal the CPP and, on December 28, 2017, published an advanced notice of proposed rulemaking regarding a CPP replacement rule.

In 2015, parties to the United Nations Framework Convention on Climate Change, including the United States, adopted the Paris Agreement, which established a non-binding universal framework for addressing greenhouse gas (GHG) emissions based on nationally determined contributions. On June 1, 2017, the U.S. President announced that the United States would withdraw from the Paris Agreement and begin renegotiating its terms. The ultimate impact of this agreement or any renegotiated agreement depends on its implementation by participating countries.

The EPA's GHG reporting rule requires annual reporting of GHG emissions expressed in terms of metric tons of $CO_2$ equivalent emissions for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2016 GHG emissions were approximately 7 million metric tons of $CO_2$ equivalent. The preliminary estimate of the Company's 2017 GHG emissions on the same basis is approximately 8 million metric tons of $CO_2$ equivalent.

**FERC Matters**

***Municipal and Rural Associations Tariff***

The Company provides wholesale electric service to Cooperative Energy, East Mississippi Electric Power Association, and the City of Collins, all located in southeastern Mississippi, under a long-term cost-based, FERC regulated MRA tariff.

In March 2016, the Company reached a settlement agreement with its wholesale customers, which was subsequently approved by the FERC, for an increase in wholesale base revenues under the MRA cost-based electric tariff, primarily as a result of placing scrubbers for Plant Daniel Units 1 and 2 in service in 2015. The settlement agreement became effective for services rendered beginning May 1, 2016, resulting in an estimated annual revenue increase of $7 million under the MRA cost-based electric tariff. Additionally, under the settlement agreement, the tariff customers agreed to similar regulatory treatment for MRA tariff ratemaking as the treatment approved for retail ratemaking under the In-Service Asset Rate Order. This regulatory treatment primarily includes (i) recovery of the operational Kemper County energy facility assets providing service to customers and other related costs, (ii) amortization of the Kemper County energy facility-related regulatory assets included in rates under the settlement agreement over the 36 months ending April 30, 2019, (iii) Kemper County energy facility-related expenses included in rates under the settlement agreement no longer being deferred and charged to expense, and (iv) removing all of the Kemper County energy facility CWIP from rate base with a corresponding increase in accrual of AFUDC. The additional resulting AFUDC totaled approximately $22 million through the suspension of Kemper IGCC start-up activities and has been recorded as a charge to income.

The Company expects to make a subsequent MRA filing during the second quarter 2018. The filing is intended to be consistent with the February 6, 2018 Mississippi PSC order for cost recovery of the Kemper County energy facility, including the impact of Tax Reform Legislation. The ultimate outcome of this matter cannot be determined at this time.

On September 18, 2017, the Company and Cooperative Energy executed a Shared Service Agreement (SSA), as part of the MRA tariff, under which the Company and Cooperative Energy will share in providing electricity to all Cooperative Energy delivery points, in lieu of the current arrangement under which each delivery point is specifically assigned to either entity. The SSA accepted by the FERC on October 31, 2017 became effective on January 1, 2018 and may be cancelled by Cooperative Energy with 10 years notice after December 31, 2020. The SSA provides Cooperative Energy the option to decrease its use of the Company's generation services under the MRA tariff, subject to annual and cumulative caps and a one-year notice requirement. In the event Cooperative Energy elects to reduce these services, the related reduction in the Company's revenues is not expected to be significant through 2020.

***Fuel Cost Recovery***

The Company has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. Effective with the first billing cycle for September 2016, fuel rates decreased $11 million annually for wholesale MRA customers and $1 million annually for wholesale MB customers. Effective January 1, 2018, the wholesale MRA fuel rate increased $11 million annually. At December 31, 2017, over-recovered wholesale MRA fuel costs were immaterial and at December 31, 2016 were approximately $13 million , which is included in over-recovered regulatory clause liabilities, current in the balance sheets.

The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor should have no significant effect on the Company's revenues or net income, but will affect cash flow.

***Market-Based Rate Authority***

The Company has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies (including the Company) and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In 2015, the FERC issued an order finding that the traditional electric operating companies' (including the Company's) and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional electric operating companies (including the Company) and Southern Power filed a request for rehearing and filed their response with the FERC in 2015.

In December 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. On May 17, 2017, the FERC accepted the traditional electric operating companies' (including the Company's) and Southern Power's compliance filing accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

On October 25, 2017, the FERC issued an order in response to the traditional electric operating companies' (including the Company's) and Southern Power's June 29, 2017 triennial updated market power analysis. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show cause within 60 days why market-based rate authority should not be revoked in certain areas adjacent to the area presently under mitigation in accordance with the February 2, 2017 order or to provide a mitigation plan to further address market power concerns. On November 10, 2017, the traditional electric operating companies (including the Company) and Southern Power responded to the FERC and proposed to resolve matters by applying the alternative mitigation authorized by the February 2, 2017 order to the adjacent areas made the subject of the October 25, 2017 order.

The ultimate outcome of these matters cannot be determined at this time.

***Cooperative Energy Power Supply Agreement***

In 2008, the Company entered into a 10-year Power Supply Agreement (PSA) with Cooperative Energy for approximately 152 MWs, which became effective in 2011. Following certain plant retirements, the PSA capacity was reduced to 86 MWs. On February 5, 2018, the Company and Cooperative Energy executed an amendment to extend the PSA through March 31, 2021, effective April 1, 2018, with increased total capacity of 286 MWs.

Cooperative Energy also has a 10-year Network Integration Transmission Service Agreement (NITSA) with SCS for transmission service to certain delivery points on the Company's transmission system that became effective in 2011. As a result of the PSA amendments, Cooperative Energy and SCS amended the terms of the NITSA on January 12, 2018 to provide for the purchase of incremental transmission capacity for service beginning April 1, 2018 through March 31, 2021. This NITSA amendment remains subject to acceptance by the FERC. The ultimate outcome of these matters cannot be determined at this time.

**Retail Regulatory Matters**

***General***

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Mississippi PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased power, energy efficiency programs, ad valorem taxes, property damage, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are expected to be recovered through the Company's base rates. See Note 3 to the financial statements under "Retail Regulatory Matters" and "Kemper County Energy Facility" for additional information.

In 2012, the Mississippi PSC issued an order for the purpose of investigating and reviewing, for informational purposes only, the ROE formulas used by the Company and all other regulated electric utilities in Mississippi. In 2013, the MPUS filed with the Mississippi PSC its report on the ROE formulas used by the Company and all other regulated electric utilities in Mississippi.

In 2014, the Mississippi PSC issued an order for the purpose of investigating and reviewing the adoption of a uniform formula rate plan for the Company and other regulated electric utilities in Mississippi.

On January 26, 2018, the Mississippi PSC issued an order directing utilities to file within 30 days information regarding the impact on rates resulting from Tax Reform Legislation. The Company's Kemper County energy facility rates, approved on February 6, 2018, include the effects of Tax Reform Legislation. The Company's 2018 ECO, revised 2018 PEP, and 2018 SRR rate filings, all submitted in February 2018, include the effects of Tax Reform Legislation and are subject to approval by the Mississippi PSC.

The ultimate outcome of these matters cannot be determined at this time.

***Performance Evaluation Plan***

The Company's retail base rates are set under the PEP, a rate plan approved by the Mississippi PSC. Two filings are made for each calendar year: the PEP projected filing, which is typically filed prior to the beginning of the year based on a projected revenue requirement, and the PEP lookback filing, which is filed after the end of the year and allows for review of the actual revenue requirement compared to the projected filing.

In 2011, the Company submitted its annual PEP lookback filing for 2010, which recommended no surcharge or refund. Later in 2011, the MPUS disputed certain items in the 2010 PEP lookback filing. In 2012, the Mississippi PSC issued an order canceling the Company's PEP lookback filing for 2011. I n 2013, the MPUS contested the Company's PEP lookback filing for 2012, which indicated a refund due to customers of $5 million . Unresolved matters related to the 2010 PEP lookback filing, which remain under review, also impact the 2012 PEP lookback filing.

In 2013, the Mississippi PSC approved the projected PEP filing for 2013, which resulted in a rate increase of 1.9% , or $15 million , annually, effective March 19, 2013. The Company may be entitled to $3 million in additional revenues related to 2013 as a result of the late implementation of the 2013 PEP rate increase.

In 2014, 2015, 2016, and 2017, the Company submitted its annual PEP lookback filings for the prior years, which for 2013 and 2014 each indicated no surcharge or refund and for each of 2015 and 2016 indicated a $5 million surcharge. Additionally, in July 2016, in November 2016, and on November 15, 2017, the Company submitted its annual projected PEP filings for 2016, 2017, and 2018, respectively, which for 2016 and 2017 indicated no change in rates and for 2018 indicated a rate increase of 4% , or $38 million in annual revenues. The Mississippi PSC suspended each of these filings to allow more time for review.

On February 7, 2018, the Company revised its annual projected PEP filing for 2018 to reflect the impacts of Tax Reform Legislation. The revised filing requests an increase of $26 million in annual revenues, based on a performance adjusted ROE of 9.33% and an increased equity ratio of 55% . See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation" herein and Note 5 to the financial statements for additional information.

The ultimate outcome of these matters cannot be determined at this time.

***Energy Efficiency***

In 2013, the Mississippi PSC approved an energy efficiency and conservation rule requiring electric and gas utilities in Mississippi serving more than 25,000 customers to implement energy efficiency programs and standards. Quick Start Plans, which include a portfolio of energy efficiency programs that are intended to provide benefits to a majority of customers, were extended by an order issued by the Mississippi PSC in July 2016, until the time the Mississippi PSC approves a comprehensive portfolio plan program. The ultimate outcome of this matter cannot be determined at this time.

On July 6, 2017, the Mississippi PSC issued an order approving the Company's Energy Efficiency Cost Rider 2017 compliance filing, which increased annual retail revenues by approximately $2 million effective with the first billing cycle for August 2017.

On November 30, 2017, the Company submitted its Energy Efficiency Cost Rider 2018 compliance filing, which included a small decrease in annual retail revenues. The ultimate outcome of this matter cannot be determined at this time.

See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

***Environmental Compliance Overview Plan***

In 2012, the Mississippi PSC approved the Company's request for a CPCN to construct scrubbers on Plant Daniel Units 1 and 2, which were placed in service in 2015. These units are jointly owned by the Company and Gulf Power, with 50% ownership each. In 2014, the Company entered into a settlement agreement with the Sierra Club under which, among other things, the Company agreed to retire, repower with natural gas, or convert to an alternative non-fossil fuel source Plant Sweatt Units 1 and 2 ( 80 MWs) no later than December 2018 (and the units were retired in July 2016). The Company also agreed that it would cease burning coal and other solid fuel at Plant Watson Units 4 and 5 ( 750 MWs) and begin operating those units solely on natural gas no later than April 2015 (which occurred in April 2015) and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 ( 200 MWs) no later than April 2016 (which occurred in February and March 2016, respectively) and begin operating those units solely on natural gas (which occurred in June and July 2016, respectively).

In accordance with a 2011 accounting order from the Mississippi PSC, the Company has the authority to defer in a regulatory asset for future recovery all plant retirement- or partial retirement-related costs resulting from environmental regulations. The Mississippi PSC approved $41 million and $17 million of costs that were reclassified to regulatory assets associated with Plant Watson and Plant Greene County, respectively, for amortization over five -year periods that began in July 2016 and July 2017, respectively. As a result, these decisions are not expected to have a material impact on the Company's financial statements.

In August 2016, the Mississippi PSC approved the Company's revised ECO plan filing for 2016, which requested the maximum 2% annual increase in revenues, or approximately $18 million , primarily related to the Plant Daniel Units 1 and 2 scrubbers placed in service in 2015. The revised rates became effective with the first billing cycle for September 2016. Approximately $22 million of related revenue requirements in excess of the 2% maximum was deferred for inclusion in the 2017 filing, along with related carrying costs.

On May 4, 2017, the Mississippi PSC approved the Company's ECO plan filing for 2017, which requested the maximum 2% annual increase in revenues, or approximately $ 18 million , primarily related to the carryforward from the prior year. The rates became effective with the first billing cycle for June 2017. Approximately $26 million of related revenue requirements in excess of the 2% maximum was deferred for inclusion in the 2018 filing, along with related carrying costs.

On February 14, 2018, the Company submitted its ECO plan filing for 2018, including the effects of Tax Reform Legislation, which requested the maximum 2% annual increase in revenues, or approximately $17 million , primarily related to the carryforward from the prior year. Approximately $13 million of related revenue requirements in excess of the 2% maximum, along with related carrying costs, remains deferred for inclusion in the 2019 filing. The ultimate outcome of this matter cannot be determined at this time.

***Fuel Cost Recovery***

The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. The Company is required to file for an adjustment to the retail fuel cost recovery factor annually. On January 12, 2017, the Mississippi PSC approved the 2017 retail fuel cost recovery factor, effective February 2017 through January 2018, which resulted in an annual revenue increase of approximately $55 million . On November 15, 2017, the Company filed its annual rate adjustment under the retail fuel cost recovery clause, requesting an additional increase of $39 million annually, which the Mississippi PSC approved on January 16, 2018 effective February 2018 through January 2019. At December 31, 2017, the amount of under-recovered retail fuel costs included in the balance sheet in customer accounts receivable was approximately $6 million compared to $37 million over recovered at December 31, 2016.

The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor should have no significant effect on the Company's revenues or net income, but will affect cash flow.

***Ad Valorem Tax Adjustment***

The Company establishes, annually, an ad valorem tax adjustment factor that is approved by the Mississippi PSC to collect the ad valorem taxes paid by the Company. On July 6, 2017, the Mississippi PSC approved the Company's annual ad valorem tax adjustment factor filing for 2017, which included an annual rate increase of 0.85% , or $8 million in annual retail revenues, primarily due to increased assessments.

***System Restoration Rider***

In February 2016, the Company submitted its 2016 SRR rate filing which proposed no changes to either the SRR rate or the annual property damage reserve accrual of $3 million annually. On February 3, 2017, the Company submitted its 2017 SRR rate filing, which proposed an increase in the property damage reserve accrual of $1 million. These filings were suspended by the Mississippi PSC for review.

On January 21, 2017, a tornado caused extensive damage to the Company's transmission and distribution infrastructure. Storm damage repairs were approximately $9 million . A portion of these costs was charged to the retail property damage reserve and was addressed in the 2018 SRR rate filing.

On February 1, 2018, the Company submitted its 2018 SRR rate filing, including the effects of Tax Reform Legislation, which proposed that the SRR rate remain at zero and the annual accrual for the property damage reserve be reduced to $2 million in 2018.

The ultimate outcome of these matters cannot be determined at this time. See Note 1 to the financial statements under "Provision for Property Damage" for additional information.

***Storm Damage Cost Recovery***

In connection with the damage associated with Hurricane Katrina, the Mississippi PSC authorized the issuance of system restoration bonds in 2006. In accordance with a Mississippi PSC order on January 24, 2017, the Company eliminated the applicable Storm Restoration Charge because the bond sinking fund managed by the Mississippi State Bond Commission is substantially funded.

**Kemper County Energy Facility**

***Overview***

The Kemper County energy facility was designed to utilize IGCC technology with an expected output capacity of 582 MWs and to be fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by the Company and situated adjacent to the Kemper County energy facility. The mine, operated by North American Coal Corporation, started commercial operation in 2013. In connection with the Kemper County energy facility construction, the Company constructed approximately 61 miles of $CO_2$ pipeline infrastructure for the transport of captured $CO_2$ for use in enhanced oil recovery.

***Schedule and Cost Estimate***

In 2012, the Mississippi PSC issued the 2012 MPSC CPCN Order, confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper County energy facility . The certificated cost estimate of the Kemper County energy facility included in the 2012 MPSC CPCN Order was $2.4 billion , net of approximately $0.57 billion in Cost Cap Exceptions. The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion , with recovery of prudently-incurred costs subject to approval by the Mississippi PSC. The Kemper County energy facility was originally projected to be placed in service in May 2014. The Company placed the combined cycle and the associated common facilities portion of the Kemper County energy facility in service in August 2014.

The initial production of syngas began on July 14, 2016 for gasifier "B" and on September 13, 2016 for gasifier "A." The Company achieved integrated operation of both gasifiers on January 29, 2017, including the production of electricity from syngas in both combustion turbines. During testing, the plant produced and captured $CO_2$ , and produced sulfuric acid and ammonia, each of acceptable quality under the related off-take agreements. However, the Company experienced numerous challenges during the extended start-up process to achieve integrated operation of the gasifiers on a sustained basis. In May 2017, after achieving these milestones, the Company determined that a critical system component, the syngas coolers, would need replacement sooner than originally planned, which would require significant lead time and significant cost. In addition, the long-term natural gas price forecast had decreased significantly and the estimated cost of operating and maintaining the facility during the first five full years of operations had increased significantly since certification.

On June 21, 2017, the Mississippi PSC stated its intent to issue an order (which occurred on July 6, 2017) directing the Company to pursue a settlement under which the Kemper County energy facility would be operated as a natural gas plant, rather than an IGCC plant, and address all issues associated with the Kemper County energy facility. On June 28, 2017, the Company notified the Mississippi PSC that it would begin a process to suspend operations and start-up activities on the gasifier portion of the Kemper County energy facility, given the uncertainty as to its future.

At the time of project suspension in June 2017, the total cost estimate for the Kemper County energy facility was approximately $7.38 billion , including approximately $5.95 billion of costs subject to the construction cost cap, and was net of the $137 million in Additional DOE Grants. In the aggregate, the Company had recorded charges to income of $3.07 billion ( $1.89 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through May 31, 2017.

Given the Mississippi PSC's stated intent regarding no further rate increase for the Kemper County energy facility and the subsequent suspension, cost recovery of the gasifier portions became no longer probable; therefore, the Company recorded an additional charge to income in June 2017 of $2.8 billion ( $2.0 billion after tax), which included estimated costs associated with the gasifier portions of the plant and lignite mine. During the third and fourth quarters of 2017, the Company recorded charges to income of $242 million ( $206 million after tax), including $164 million for ongoing project costs, estimated mine and gasifier-related costs, and certain termination costs during the suspension period prior to conclusion of the Kemper Settlement Docket , as well as the charge associated with the Kemper Settlement Agreement discussed below. Additional pre-tax cancellation costs, including mine and plant closure and contract termination costs, currently estimated at approximately $50 million to $100 million (excluding salvage), are expected to be incurred in 2018. The Company has begun efforts to dispose of or abandon the mine and gasifier-related assets.

***Rate Recovery***

*Kemper Settlement Agreement*

On February 6, 2018, the Mississippi PSC voted to approve the Kemper Settlement Agreement. The Kemper Settlement Agreement provides for an annual revenue requirement of approximately $99.3 million for costs related to the Kemper County energy facility, which includes the impact of Tax Reform Legislation. The revenue requirement is based on (i) a fixed ROE for 2018 of 8.6% excluding any performance adjustment, (ii) a ROE for 2019 calculated in accordance with PEP, excluding the performance adjustment, (iii) for future years, a performance-based ROE calculated pursuant to PEP, and (iv) amortization periods for the related regulatory assets and liabilities of eight years and six years, respectively. The revenue requirement also reflects a disallowance related to a portion of the Company's investment in the Kemper County energy facility requested for inclusion in rate base, which was recorded in the fourth quarter 2017 as an additional charge to income of approximately $78 million ( $85 million net of accumulated depreciation of $7 million ) pre-tax ( $48 million after tax).

Under the Kemper Settlement Agreement, retail customer rates will reflect a reduction of approximately $26.8 million annually and include no recovery for costs associated with the gasifier portion of the Kemper County energy facility in 2018 or at any future date. On February 12, 2018, the Company made the required compliance filing with the Mississippi PSC. The Kemper

Settlement Agreement also requires (i) the CPCN for the Kemper County energy facility to be modified to limit it to natural gas combined cycle operation and (ii) the Company to file a reserve margin plan with the Mississippi PSC by August 2018.

As of December 31, 2017, the balances associated with the Kemper County energy facility regulatory assets and liabilities were $114 million and $26 million , respectively.

As a result of the Mississippi PSC order on February 6, 2018, rate recovery for the Kemper County energy facility is resolved, subject to any future legal challenges.

*2015 Rate Case*

On December 3, 2015, the Mississippi PSC issued the In-Service Asset Rate Order r egarding the Kemper County energy facility assets that were commercially operational and currently providing service to customers (the transmission facilities, combined cycle, natural gas pipeline, and water pipeline) and other related costs. The In-Service Asset Rate Order provided for retail rate recovery of an annual revenue requirement of approximately $126 million , based on the Company's actual average capital structure, with a maximum common equity percentage of 49.733% , a 9.225% return on common equity, and actual embedded interest costs. The In-Service Asset Rate Order also included a prudence finding of all costs in the stipulated revenue requirement calculation for the in-service assets.

In connection with the implementation of the In-Service Asset Rate Order and wholesale rates, the Company began expensing certain ongoing project costs and certain retail debt carrying costs that previously were deferred and began amortizing certain regulatory assets associated with assets placed in service and consulting and legal fees over periods ranging from two years to 10 years. On July 6, 2017, the Mississippi PSC issued an order requiring the Company to establish a regulatory liability account to maintain current rates related to the Kemper County energy facility following the July 2017 completion of the amortization period for certain of these regulatory assets. See "FERC Matters" herein for additional information related to the 2016 settlement agreement with wholesale customers.

***Lignite Mine and $CO_2$ Pipeline Facilities***

The Company owns the lignite mine and equipment and mineral reserves located around the Kemper County energy facility site. The mine started commercial operation in June 2013.

In 2010, the Company executed a 40 -year management fee contract with Liberty Fuels Company, LLC (Liberty Fuels), a wholly-owned subsidiary of The North American Coal Corporation, which developed, constructed, and is responsible for the mining operations through the end of the mine reclamation. As the mining permit holder, Liberty Fuels has a legal obligation to perform mine reclamation and the Company has a contractual obligation to fund all reclamation activities. The Company expects mine reclamation to begin in 2018. In addition to the obligation to fund the reclamation activities, the Company provided working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" and "Variable Interest Entities" for additional information.

In addition, the Company constructed the $CO_2$ pipeline for the planned transport of captured $CO_2$ for use in enhanced oil recovery and entered into an agreement with Denbury Onshore (Denbury) to purchase the captured $CO_2$ . Denbury has the right to terminate the contract at any time because the Company did not place the Kemper IGCC in service by July 1, 2017.

The ultimate outcome of these matters cannot be determined at this time.

***Litigation***

On April 26, 2016, a complaint against the Company was filed in Harrison County Circuit Court (Circuit Court) by Biloxi Freezing & Processing Inc., Gulfside Casino Partnership, and John Carlton Dean, which was amended and refiled on July 11, 2016 to include, among other things, Southern Company as a defendant. The individual plaintiff alleges that the Company and Southern Company violated the Mississippi Unfair Trade Practices Act. All plaintiffs have alleged that the Company and Southern Company concealed, falsely represented, and failed to fully disclose important facts concerning the cost and schedule of the Kemper County energy facility and that these alleged breaches have unjustly enriched the Company and Southern Company. The plaintiffs seek unspecified actual damages and punitive damages; ask the Circuit Court to appoint a receiver to oversee, operate, manage, and otherwise control all affairs relating to the Kemper County energy facility; ask the Circuit Court to revoke any licenses or certificates authorizing the Company or Southern Company to engage in any business related to the Kemper County energy facility in Mississippi; and seek attorney's fees, costs, and interest. The plaintiffs also seek an injunction to prevent any Kemper County energy facility costs from being charged to customers through electric rates. On June 23, 2017, the Circuit Court ruled in favor of motions by Southern Company and the Company and dismissed the case. On July 7, 2017, the plaintiffs filed notice of an appeal. The Company believes this legal challenge has no merit; however, an adverse outcome in this proceeding could have a material impact on the Company's results of operations, financial condition, and liquidity. The Company intends to vigorously defend itself in this matter and the ultimate outcome of this matter cannot be determined at this time.

On June 9, 2016, Treetop, Greenleaf $CO_2$ Solutions, LLC (Greenleaf), Tenrgys, LLC, Tellus Energy, LLC, WCOA, LLC, and Tellus Operating Group filed a complaint against the Company, Southern Company, and SCS in the state court in Gwinnett County, Georgia. The complaint related to the cancelled $CO_2$ contract with Treetop and alleged fraudulent misrepresentation, fraudulent concealment, civil conspiracy, and breach of contract on the part of the Company, Southern Company, and SCS and sought compensatory damages of $100 million , as well as unspecified punitive damages. Southern Company, the Company, and SCS moved to compel arbitration pursuant to the terms of the $CO_2$ contract, which the court granted on May 4, 2017. On June 28, 2017, Treetop, Greenleaf, Tenrgys, LLC, Tellus Energy, LLC, WCOA, LLC, and Tellus Operating Group filed a claim for arbitration requesting $500 million in damages. On December 28, 2017, the Company reached a settlement agreement with Treetop, Greenleaf, Tenrgys, LLC, Tellus Energy, LLC, WCOA, LLC, and Tellus Operating Group and the arbitration was dismissed.

See Note 3 to the financial statements under "Kemper County Energy Facility" for additional information.

**Income Tax Matters**

***Federal Tax Reform Legislation***

On December 22, 2017, the Tax Reform Legislation was signed into law and became effective on January 1, 2018. The Tax Reform Legislation, among other things, reduces the federal corporate income tax rate to 21%, retains normalization provisions for public utility property and existing renewable energy incentives, and repeals the corporate alternative minimum tax.

Regulated utility businesses can continue deducting all business interest expense and are not eligible for bonus depreciation on capital assets acquired and placed in service after September 27, 2017. Projects with binding contracts before September 28, 2017 and placed in service after September 27, 2017 remain eligible for bonus depreciation under the Protecting Americans from Tax Hikes (PATH) Act.

In addition, under the Tax Reform Legislation, net operating losses (NOL) generated after December 31, 2017 can no longer be carried back to previous tax years but can be carried forward indefinitely, with utilization limited to 80% of taxable income in the subsequent tax year.

For the year ended December 31, 2017, implementation of the Tax Reform Legislation resulted in an estimated net tax expense of $372 million and a $375 million increase in regulatory liabilities as of December 31, 2017, primarily due to the impact of the reduction of the corporate income tax rate on deferred tax assets and liabilities.

The Tax Reform Legislation is subject to further interpretation and guidance from the IRS, as well as each respective state's adoption. In addition, the regulatory treatment of certain impacts of the Tax Reform Legislation is subject to the discretion of the FERC and the Mississippi PSC. On January 31, 2018, SCS, on behalf of the traditional electric operating companies (including the Company), filed with the FERC a reduction to the Company's open access transmission tariff charge for 2018 to reflect the revised federal corporate tax rate. See Note 3 to the financial statements under "Regulatory Matters" for additional information regarding the Company's rate filings to reflect the impacts of the Tax Reform Legislation.

See FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein and Note 5 to the financial statements under "Current and Deferred Income Taxes" for additional information.

The ultimate outcome of these matters cannot be determined at this time.

***Bonus Depreciation***

Under the Tax Reform Legislation, projects with binding contracts prior to September 28, 2017 and placed in service after September 27, 2017 remain eligible for bonus depreciation under the PATH Act. The PATH Act allowed for 50% bonus depreciation for 2015 through 2017, 40% bonus depreciation for 2018, and 30% bonus depreciation for 2019 and certain long-lived assets placed in service in 2020. Based on provisional estimates, approximately $50 million of positive cash flows is expected to result from bonus depreciation for the 2017 tax year and approximately $10 million for the 2018 tax year. Should Southern Company have a NOL in 2018, all of these cash flows may not be fully realized in 2018. All projected tax benefits previously received for bonus depreciation related to the Kemper IGCC were repaid in connection with third quarter 2017 estimated tax payments. Additionally, Southern Company will record an abandonment loss on its 2018 corporate income tax return, which may not be fully realized should Southern Company have a NOL in 2018. See Notes 3 and 5 to the financial statements under "Kemper County Energy Facility" and "Current and Deferred Income Taxes," respectively, for additional information. The ultimate outcome of these matters cannot be determined at this time.

***Section 174 Research and Experimental Deduction***

Southern Company, on behalf of the Company, has reflected deductions for R&E expenditures related to the Kemper County energy facility in its federal income tax calculations since 2013 and filed amended federal income tax returns for 2008 through 2013 to also include such deductions. In December 2016, Southern Company and the IRS reached a proposed settlement, which was approved on September 8, 2017 by the U.S. Congress Joint Committee on Taxation (JCT), resolving a methodology for these deductions. As a result of this approval, the Company recognized $176 million of previously unrecognized tax benefits and reversed $36 million of associated accrued interest.

**Other Matters**

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as standards for air, water, land, and protection of other natural resources, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by $CO_2$ and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters.

The ultimate outcome of such pending or potential litigation or regulatory matters cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

In 2013, the Company submitted a claim under the Deep Horizon Economic and Property Damages Settlement Agreement associated with the oil spill that occurred in the Gulf of Mexico. The ultimate outcome of this matter cannot be determined at this time.

In 2016, the SEC began conducting a formal investigation of Southern Company and the Company concerning the estimated costs and expected in-service date of the Kemper County energy facility. On November 30, 2017, the SEC staff notified Southern Company that it had concluded its investigation with no recommended enforcement action.

**ACCOUNTING POLICIES**

**Application of Critical Accounting Policies and Estimates**

The Company prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

***Utility Regulation***

The Company is subject to retail regulation by the Mississippi PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation and pension and other postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and any requirement to refund these regulatory liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

***Kemper County Energy Facility Rate Recovery***

For periods prior to the second quarter 2017, significant accounting estimates included Kemper County energy facility estimated construction costs, project completion date, and rate recovery. The Company recorded total pre-tax charges to income related to the Kemper County energy facility of $428 million ($264 million after tax) in 2016, $365 million ($226 million after tax) in 2015, $868 million ($536 million after tax) in 2014, and $1.2 billion ($729 million after tax) in prior years.

As a result of the Mississippi PSC's June 21, 2017 stated intent to issue an order (which occurred on July 6, 2017) directing the Company to pursue a settlement under which the Kemper County energy facility would be operated as a natural gas plant rather than an IGCC plant, as well as the Company's June 28, 2017 suspension of the operation and start-up of the gasifier portion of the Kemper County energy facility, the estimated construction costs and project completion date are no longer considered significant accounting estimates.

Given the Mississippi PSC's stated intent regarding no further rate increase for the Kemper County energy facility and the subsequent suspension, cost recovery of the gasifier portions became no longer probable; therefore, the Company recorded an additional charge to income in June 2017 of $2.8 billion ($2.0 billion after tax), which included estimated costs associated with the gasifier portions of the plant and lignite mine. During the third and fourth quarters of 2017, the Company recorded charges to income of $242 million ($206 million after tax), including $164 million for ongoing project costs, estimated mine and gasifier-related costs, and certain termination costs during the suspension period prior to conclusion of the Kemper Settlement Docket, as well as a charge of $78 million associated with the Kemper Settlement Agreement.

In the aggregate, since the Kemper County energy facility project started, the Company has incurred charges of $6.20 billion ($4.14 billion after tax) through December 31, 2017. See Note 11 to the financial statements for additional information on the individual charges by quarter.

As a result of the Mississippi PSC order on February 6, 2018, rate recovery for the Kemper County energy facility is resolved, subject to any future legal challenges, and no longer represents a critical accounting estimate.

See Note 3 to the financial statements under "Kemper County Energy Facility" for additional information.

***Federal Tax Reform Legislation***

Following the enactment of Tax Reform Legislation, the SEC staff issued Staff Accounting Bulletin 118 – "Income Tax Accounting Implications of the Tax Cuts and Jobs Act" (SAB 118), which provides for a measurement period of up to one year from the enactment date to complete accounting under GAAP for the tax effects of the legislation. Due to the complex and comprehensive nature of the enacted tax law changes, and their application under GAAP, the Company considers all amounts recorded in the financial statements as a result of Tax Reform Legislation to be "provisional" as discussed in SAB 118 and subject to revision. The Company is awaiting additional guidance from industry and income tax authorities in order to finalize its accounting. The ultimate impact of Tax Reform Legislation on deferred income tax assets and liabilities and the related regulatory assets and liabilities cannot be determined at this time. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation" herein and Notes 3 and 5 to the financial statements under "Retail Regulatory Matters – Rate Plans" and "Current and Deferred Income Taxes," respectively, for additional information.

***Asset Retirement Obligations***

AROs are computed as the fair value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities.

The liability for AROs primarily relates to facilities that are subject to the CCR Rule, principally ash ponds. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, deep injection wells, water wells, substation removal, mine reclamation, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities and certain wireless communication towers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO.

The cost estimates for AROs related to the disposal of CCR are based on information using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure. As further analysis is performed and closure details are developed, the Company will continue to periodically update these cost estimates as necessary. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations – Coal Combustion Residuals" herein and Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

Given the significant judgment involved in estimating AROs, the Company considers the liabilities for AROs to be critical accounting estimates.

***Pension and Other Postretirement Benefits***

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on pension and other postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. For purposes of determining its liability related to the pension and other postretirement benefit plans, the Company discounts the future related cash flows using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments. For 2015 and prior years, the Company computed the interest cost component of its net periodic pension and other postretirement benefit plan expense using the same single-point discount rate. Beginning in 2016, the Company adopted a full yield curve approach for calculating the interest cost component whereby the discount rate for each year is applied to the liability for that specific year. As a result, the interest cost component of net periodic pension and other postretirement benefit plan expense decreased by approximately $4 million in 2016.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $2 million or less change in total annual benefit expense and a $25 million or less change in projected obligations.

See Note 2 to the financial statements for additional information regarding pension and other postretirement benefits.

***Allowance for Funds Used During Construction***

In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in the calculation of taxable income. The average annual AFUDC rate was 6.7% , 6.5% , and 5.99% for the years ended December 31, 2017 , 2016 , and 2015 , respectively. The AFUDC rate is applied to CWIP consistent with jurisdictional regulatory treatment. AFUDC equity was $72 million , $124 million, and $110 million in 2017, 2016, and 2015, respectively. The decrease in 2017 resulted from the Kemper County energy facility project suspension in June 2017.

***Unbilled Revenues***

Revenues related to the retail sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, power delivery volume, and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

***Contingent Obligations***

The Company is subject to a number of federal and state laws and regulations as well as other factors and conditions that subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's results of operations, cash flows, or financial condition.

**Recently Issued Accounting Standards**

***Revenue***

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers* (ASC 606), replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the new standard is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

Most of the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term , as well as longer-term contractual commitments, including PPAs.

The Company has completed the evaluation of all revenue streams and determined that the adoption of ASC 606 will not change the current timing of revenue recognition for such transactions. Some revenue arrangements, such as energy-related derivatives and alternative revenue programs, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed or presented separately from revenues under ASC 606 on the Company's financial statements, if material. The Company has concluded contributions in aid of construction are not in scope for ASC 606 and will continue to be accounted for as an offset to property, plant, and equipment.

The new standard is effective for reporting periods beginning after December 15, 2017. The Company applied the modified retrospective method of adoption effective January 1, 2018. The Company also utilized practical expedients which allowed it to apply the standard to open contracts at the date of adoption and to reflect the aggregate effect of all modifications when identifying performance obligations and allocating the transaction price for contracts modified before the effective date. Under the modified retrospective method of adoption, prior year reported results are not restated; however, a cumulative-effect adjustment to retained earnings at January 1, 2018 is recorded. In addition, quarterly disclosures will include comparative information on 2018 financial statement line items under current guidance. The adoption of ASC 606 did not result in a cumulative-effect adjustment .

***Leases***

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged . ASU 2016-02 is effective for fiscal years beginning after December 15, 2018 and the Company will adopt the new standard effective January 1, 2019.

The Company is currently implementing an information technology system along with the related changes to internal controls and accounting policies that will support the accounting for leases under ASU 2016-02. In addition, the Company has substantially completed a detailed inventory and analysis of its leases. In terms of rental charges and duration of contracts, the most significant leases relate to equipment and cellular towers where the Company is the lessee and to equipment where the Company is the lessor. The Company is currently analyzing pole attachment agreements and a lease determination has not been made at this time. While the Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

***Other***

On March 10, 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017-07). ASU 2017-07 requires that an employer report the service cost component in the same line item or items as other compensation costs and requires the other components of net periodic pension and postretirement benefit costs to be separately presented in the income statement outside of income from operations. Additionally, only the service cost component is eligible for capitalization, when applicable. However, all cost components remain eligible for capitalization under FERC regulations. ASU 2017-07 will be applied retrospectively for the presentation of the service cost component and the other components of net periodic pension and postretirement benefit costs in the income statement. The capitalization of only the service cost component of net periodic pension and postretirement benefit costs in assets will be applied on a prospective basis. ASU 2017-07 is effective for periods beginning after December 15, 2017. The presentation changes required for net periodic pension and postretirement benefit costs will result in a decrease in the Company's operating income and an increase in other income for 2016 and 2017 and are expected to result in a decrease in operating income and an increase in other income for 2018. The Company adopted ASU 2017-07 effective January 1, 2018 with no material impact on its financial statements.

On August 28, 2017, the FASB issued ASU No. 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities* (ASU 2017-12), amending the hedge accounting recognition and presentation requirements. ASU 2017-12 makes more financial and non-financial hedging strategies eligible for hedge accounting, amends the related presentation and disclosure requirements, and simplifies hedge effectiveness assessment requirements. ASU 2017-12 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

## FINANCIAL CONDITION AND LIQUIDITY

### Overview and Sources of Capital

Earnings for all periods presented were negatively affected by charges associated with the Kemper IGCC. See FUTURE EARNINGS POTENTIAL – "Kemper County Energy Facility" herein and Note 3 to the financial statements for additional information.

The Company's cash requirements primarily consist of funding ongoing operations, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to maintain existing generation facilities, to comply with environmental regulations including adding environmental modifications to certain existing generating units, to expand and improve transmission and distribution facilities, and for restoration following major storms.

The Company's financial statement presentation contemplates continuation of the Company as a going concern as a result of Southern Company's anticipated ongoing financial support of the Company. Specifically, the Company has been informed by Southern Company that in the event sufficient funds are not available from external sources, Southern Company intends to provide the Company with loans and/or equity contributions sufficient to fund the remaining indebtedness scheduled to mature and other cash needs over the next 12 months. For additional information, see Note 6 to the financial statements under "Going Concern."

On February 28, 2017, the maturity dates for $551 million in promissory notes to Southern Company were extended to July 31, 2018. In the second quarter 2017, the Company borrowed an additional $40 million under a promissory note issued to Southern Company. In June 2017, Southern Company made equity contributions totaling $1.0 billion to the Company. The Company used a portion of the proceeds to (i) prepay $300 million of the outstanding principal amount under its $1.2 billion unsecured term loan; (ii) repay all of the $591 million outstanding principal amount of promissory notes to Southern Company; and (iii) repay $10 million of the outstanding principal amount of bank loans.

In September 2017, the Company issued a floating rate promissory note to Southern Company in an aggregate principal amount of up to $150 million bearing interest based on one-month LIBOR. The Company borrowed $109 million under this promissory note primarily to satisfy its federal income tax obligations for the quarter ended September 30, 2017 and subsequently repaid the promissory note upon receipt of its income tax refund from the U.S. government related to the settlement concerning deductible R&E expenditures. See Note 5 to the financial statements under "Section 174 Research and Experimental Deduction" for additional information.

As of December 31, 2017, the Company's current liabilities exceeded current assets by approximately $911 million primarily due to a $900 million unsecured term loan that matures on March 31, 2018. The Company expects to refinance the unsecured term loan with external security issuances and/or borrowings from financial institutions or Southern Company. To fund the Company's capital needs over the next 12 months, the Company intends to utilize operating cash flows, external security issuances, lines of credit, bank term loans, equity contributions from Southern Company, and, to the extent necessary, loans from Southern Company.

The Company's capital expenditures and debt maturities are expected to materially exceed operating cash flows through 2022. The Company plans to obtain the funds required for construction and other purposes from operating cash flows, lines of credit, bank term loans, external security issuances, commercial paper, to the extent the Company is eligible to participate, and loans and/or equity contributions from Southern Company.

The Company's investments in the qualified pension plan increased in value as of December 31, 2017 as compared to December 31, 2016. No contributions to the qualified pension plan were made for the year ended December 31, 2017 and no mandatory contributions to the qualified pension plan are anticipated during 2018.

Net cash provided from operating activities totaled $503 million for 2017, an increase of $274 million as compared to 2016. The increase in cash provided from operating activities in 2017 was primarily due to tax refunds associated with the approval by the JCT of the Section 174 R&E settlement, largely offset by a decrease in income taxes related to the Kemper County energy facility and Tax Reform Legislation. Net cash provided from operating activities totaled $229 million for 2016, an increase of $56 million as compared to 2015. The increase in cash provided from operating activities in 2016 was primarily due to repayment in 2015 of ITCs relating to the Kemper County energy facility, as well as the 2015 mirror CWIP refund, partially offset by lower income tax benefits related to the Kemper County energy facility in 2016 and lower fuel rates in 2016.

Net cash used for investing activities in 2017, 2016, and 2015 totaled $504 million , $697 million , and $906 million , respectively. The cash used for investing activities in all years presented was primarily due to gross property additions related to the Kemper County energy facility. The cash used for investing activities in 2016 was partially offset by the receipt of Additional DOE Grants. The cash used for investing activities in 2015 also included gross property additions related to the Plant Daniel scrubber project.

Net cash provided from financing activities totaled $25 million in 2017 primarily due to capital contributions from Southern Company, largely offset by redemptions of long-term debt and short-term borrowings. Net cash provided from financing activities totaled $594 million in 2016 primarily due to long-term debt financings and capital contributions from Southern Company, partially offset by a decrease in short-term borrowings and redemptions of long-term debt. Net cash provided from financing activities totaled $698 million in 2015 primarily due to short-term borrowings, capital contributions from Southern Company, and long-term debt financings, partially offset by redemptions of long-term debt.

Significant balance sheet changes as of December 31, 2017 compared to 2016 include decreases of $2.5 billion in CWIP, a net change of $1.0 billion in accumulated deferred income taxes, an increase in paid-in capital of $1.0 billion due to capital contributions from Southern Company, a portion of which was used to repay $300 million of securities due within one year, $591 million of long-term debt, and $10 million of short-term debt. Long-term debt decreased primarily due to the reclassification of $1.2 billion in unsecured term loans to securities due within one year – other. Securities due within one year – parent decreased $551 million due to the repayment of promissory notes to Southern Company. Other significant balance sheet changes include $326 million in deferred charges related to income taxes. All of these changes primarily resulted from the Kemper IGCC suspension and related estimated loss. Income taxes receivable and unrecognized tax benefits also decreased due to tax refunds associated with the approval by the JCT of the Section 174 R&E settlement. The Company also had an increase of $365 million in deferred credits related to income taxes primarily resulting from the impacts of Tax Reform Legislation. See FUTURE EARNINGS POTENTIAL – "Kemper County Energy Facility" and "Income Tax Matters – Federal Tax Reform Legislation" herein and Notes 3 and 5 to the financial statements under "Kemper County Energy Facility" and "Section 174 Research and Experimental Deduction," respectively, for additional information.

The Company's ratio of common equity to total capitalization plus short-term debt was 39% and 49% at December 31, 2017 and 2016, respectively. The decrease was due to Kemper IGCC losses. See Note 6 to the financial statements for additional information.

The issuance of securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended. The amounts of securities authorized by the FERC are continuously monitored and appropriate filings are made to ensure flexibility in raising capital. Any future financing through secured debt would also require approval by the Mississippi PSC.

The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company in the Southern Company system.

At December 31, 2017 , the Company had approximately $248 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2017 were $100 million, all of which is unused. In November 2017, the Company amended its one-year credit arrangements in an aggregate amount of $100 million to extend the maturity dates from 2017 to 2018.

A portion of the $100 million unused credit arrangements with banks is allocated to provide liquidity support to the Company's revenue bonds. The amount of variable rate revenue bonds outstanding requiring liquidity support as of December 31, 2017 was approximately $40 million. In addition, the Company had approximately $50 million of fixed rate revenue bonds that were remarketed from a long-term interest rate mode to an index rate mode subsequent to December 31, 2017.

Most of these bank credit arrangements, as well as the Company's term loan agreement, contain covenants that limit debt levels and typically contain cross acceleration to other indebtedness (including guarantee obligations) of the Company. Such cross-acceleration provisions to other indebtedness would trigger an e vent of default if the Company defaulted on indebtedness, the payment of which was then a ccelerated. At December 31, 2017, the Company was in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowing.

Subject to applicable market conditions, the Company expects to seek to renew or replace its credit arrangements as needed, prior to expiration. In connection therewith, the Company may extend the maturity dates and/or increase or decrease the lending commitments thereunder.

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

Short-term borrowings are included in notes payable in the balance sheets. Details of short-term borrowing were as follows:

| | Short-term Debt at the End of the Period | | Short-term Debt During the Period (*) | | |
|---|---|---|---|---|---|
| | Amount Outstanding | Weighted Average Interest Rate | Average Outstanding | Weighted Average Interest Rate | Maximum Amount Outstanding |
| | *(in millions)* | | *(in millions)* | | *(in millions)* |
| **December 31, 2017** | **$ 4** | **3.8%** | **$ 18** | **3.0%** | **$ 36** |
| December 31, 2016 | $ 23 | 2.6% | $ 112 | 2.0% | $ 500 |
| December 31, 2015 | $ 500 | 1.4% | $ 372 | 1.3% | $ 515 |

(*) Average and maximum amounts are based upon daily balances during the 12-month periods ended December 31.

## Financing Activities

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, the Company plans, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

### *Bank Term Loans and Senior Notes*

In March 2017, the Company issued a $9 million short-term bank note bearing interest at 5% per annum, which was repaid in April 2017.

In June 2017, the Company used a portion of the proceeds from Southern Company equity contributions to prepay $300 million of the outstanding principal amount under its $1.2 billion unsecured term loan, which matures on March 30, 2018, and to repay $10 million of the outstanding principal amount of bank loans. See "Parent Company Loans and Equity Contributions" herein for more information.

This unsecured term loan has covenants that limit debt levels to 65% of total capitalization, as defined in the agreement. For purposes of this definition, debt excludes the long-term debt payable to affiliated trusts and other hybrid securities. In addition, this unsecured term loan contains cross-acceleration provisions to other debt (including guarantee obligations) that would be triggered if the Company defaulted on debt above a specified threshold, the payment of which was then accelerated. The Company is currently in compliance with all such covenants.

In August 2017, the Company repaid a $12.5 million short-term bank note.

In November 2017, the Company repaid at maturity $35 million aggregate principal amount of Series 2007A 5.60% Senior Notes.

### *Parent Company Loans and Equity Contributions*

In February 2017, the Company amended $551 million in promissory notes to Southern Company extending the maturity dates of the notes from December 1, 2017 to July 31, 2018. In the second quarter 2017, the Company borrowed an additional $40 million under a promissory note issued to Southern Company.

In June 2017, Southern Company made equity contributions totaling $1.0 billion to the Company. The Company used a portion of the proceeds to (i) prepay $300 million of the outstanding principal amount under its $1.2 billion unsecured term loan, which matures on March 30, 2018; (ii) repay all of the $591 million outstanding principal amount of promissory notes to Southern Company; and (iii) repay a $10 million short-term bank loan.

In September 2017, the Company issued a floating rate promissory note to Southern Company in an aggregate principal amount of up to $150 million bearing interest based on one-month LIBOR. The Company borrowed $109 million under this promissory note primarily to satisfy its federal income tax obligations for the quarter ending September 30, 2017 and subsequently repaid the promissory note upon receipt of its income tax refund from the U.S. federal government related to the settlement concerning deductible R&E expenditures. See Note 5 to the financial statements under "Section 174 Research and Experimental Deduction" for additional information.

**Credit Rating Risk**

At December 31, 2017 , the Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

On October 4, 2017, the Company executed agreements with its largest retail customer, Chevron, to continue providing retail service to the Chevron refinery in Pascagoula, Mississippi through 2038. The agreements grant Chevron a security interest in the co-generation assets, with a net book value of approximately $93 million, located at the refinery that is exercisable upon the occurrence of (i) certain bankruptcy events or (ii) other events of default coupled with specific reductions in steam output at the facility and a downgrade of the Company's credit rating to below investment grade by two of the three rating agencies.

There are certain contracts that have required or could require collateral, but not accelerated payment, in the event of a credit rating change to BBB and/or Baa2 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, energy price risk management, and transmission. At December 31, 2017 , the maximum amount of potential collateral requirements under these contracts at a rating of BBB and/or Baa2 or BBB- and/or Baa3 was not material. The maximum potential collateral requirements at a rating below BBB- and/or Baa3 equaled approximately $241 million.

Included in these amounts are certain agreements that could require collateral in the event that Alabama Power or Georgia Power has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact the ability of the Company to access capital markets, or at a minimum the cost at which it does so.

On March 1, 2017, Moody's downgraded the senior unsecured debt rating of the Company to Ba1 from Baa3.

On March 24, 2017, S&P revised its consolidated credit rating outlook for Southern Company and its subsidiaries (including the Company) from stable to negative.

On March 30, 2017, Fitch placed the ratings of the Company on rating watch negative.

On June 22, 2017, Moody's placed the ratings of the Company on review for downgrade. On September 21, 2017, Moody's revised its rating outlook for the Company from under review to stable.

While it is unclear how the credit rating agencies, the FERC, and the Mississippi PSC may respond to the Tax Reform Legislation, certain financial metrics, such as the funds from operations to debt percentage, used by the credit rating agencies to assess Southern Company and its subsidiaries, including the Company, may be negatively impacted. Absent actions by Southern Company and its subsidiaries, including the Company, to mitigate the resulting impacts, which, among other alternatives, could include adjusting capital structure and/or monetizing regulatory assets, the Company's credit ratings could be negatively affected. See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

**Market Price Risk**

Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques that include, but are not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to a change in interest rates, the Company may enter into derivatives that have been designated as hedges. The weighted average interest rate on $40 million of long-term variable interest rate exposure at December 31, 2017 was 2.49%. If the Company sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would have an immaterial effect on annualized interest expense at December 31, 2017 . See Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases. The Company continues to manage retail fuel-hedging programs implemented per the guidelines of the Mississippi PSC and wholesale fuel-hedging programs under agreements with wholesale customers. The Company had no material change in market risk exposure for the year ended December 31, 2017 when compared to the year ended December 31, 2016 .

The changes in fair value of energy-related derivative contracts are substantially attributable to both the volume and the price of natural gas. For the years ended December 31, the changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, were as follows:

| | **2017 Changes** | 2016 Changes |
|---|---|---|
| | Fair Value | |
| | *(in millions)* | |
| Contracts outstanding at the beginning of the period, assets (liabilities), net | **$ (7)** | $ (47) |
| Contracts realized or settled | **8** | 29 |
| Current period changes (*) | **(8)** | 11 |
| Contracts outstanding at the end of the period, assets (liabilities), net | **$ (7)** | $ (7) |

(*) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The net hedge volumes of energy-related derivative contracts, all of which are natural gas swaps, for the years ended December 31 were as follows:

| | **2017** | 2016 |
|---|---|---|
| | mmBtu Volume | |
| | *(in millions)* | |
| Total hedge volume | **53** | 36 |

For natural gas hedges, the weighted average swap contract cost above market prices was approximately $0.14 per mmBtu as of December 31, 2017 and $0.19 per mmBtu as of December 31, 2016 . The options outstanding were immaterial for the reporting periods presented. The costs associated with natural gas hedges are recovered through the Company's ECMs.

At December 31, 2017 and 2016 , substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were related to the Company's fuel-hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the ECM clause.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2 of the fair value hierarchy. See Note 9 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2017 were as follows:

| | **Fair Value Measurements December 31, 2017** | | |
|---|---|---|---|
| | Total | Maturity | |
| | Fair Value | Year 1 | Years 2&3 |
| | *(in millions)* | | |
| Level 1 | $ — | $ — | $ — |
| Level 2 | (7) | (5) | (2) |
| Level 3 | — | — | — |
| Fair value of contracts outstanding at end of period | $ (7) | $ (5) | $ (2) |

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure.

Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements.

**Capital Requirements and Contractual Obligations**

Approximately $900 million will be required through December 31, 2018 to fund maturities of long-term debt. In addition, the Company has $40 million of tax-exempt variable rate demand obligations that are supported by short-term credit facilities and $50 million of fixed rate revenue bonds that were remarketed from a long-term interest rate mode to an index rate mode subsequent to December 31, 2017. See "Overview and Sources of Capital" herein for additional information.

The construction program of the Company is currently estimated to be $213 million for 2018 , $199 million for 2019 , $193 million for 2020 , $167 million for 2021, and $118 million for 2022. These estimated program amounts also include capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental laws and regulations included in these amounts are $14 million, $16 million, $17 million, $13 million, and $3 million for 2018 , 2019 , 2020 , 2021, and 2022, respectively. These estimated expenditures do not include any potential compliance costs associated with the regulation of $CO_2$ emissions from fossil fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations" and "– Global Climate Issues" herein for additional information.

The Company also anticipates costs associated with closure and monitoring of ash ponds in accordance with the CCR Rule, which are reflected in the Company's ARO liabilities. These costs, which could change as the Company continues to refine its assumptions underlying the cost estimates and evaluate the method and timing of compliance activities, are estimated to be $23 million, $7 million, $7 million, $9 million, and $12 million for the years 2018, 2019, 2020, 2021, and 2022, respectively. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts; changes in environmental laws and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing electric generating units, to meet regulatory requirements; changes in FERC rules and regulations; Mississippi PSC approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the FERC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred stock dividends, unrecognized tax benefits, pension and other post-retirement benefit plans, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 10 to the financial statements for additional information.

**MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)**
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**Contractual Obligations**

Contractual obligations at December 31, 2017 were as follows:

| | 2018 | 2019-2020 | 2021-2022 | After 2022 | Total |
|---|---|---|---|---|---|
| | | | *(in millions)* | | |
| Long-term debt [(a)] — | | | | | |
| Principal | $ 990 | $ 125 | $ 270 | $ 673 | $ 2,058 |
| Interest | 86 | 106 | 79 | 552 | 823 |
| Preferred stock dividends [(b)] | 2 | 3 | 3 | — | 8 |
| Financial derivative obligations [(c)] | 6 | 3 | — | — | 9 |
| Operating leases [(d)] | 3 | 5 | 4 | 7 | 19 |
| Purchase commitments — | | | | | |
| Capital [(e)] | 213 | 379 | 269 | — | 861 |
| Fuel [(f)] | 280 | 329 | 191 | 175 | 975 |
| Long-term service agreements [(g)] | 33 | 75 | 49 | 245 | 402 |
| Purchased power [(h)] | 11 | 29 | 36 | 454 | 530 |
| Pension and other postretirement benefits plans [(i)] | 7 | 15 | — | — | 22 |
| Total | $ 1,631 | $ 1,069 | $ 901 | $ 2,106 | $ 5,707 |

(a) All amounts are reflected based on final maturity dates except for amounts related to certain revenue bonds. The Company plans to continue, when economically feasible, to retire higher-cost sec urities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of December 31, 2017, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately). For additional information, see Note 6 to the financial statements.

(b) Preferred stock does not mature; therefore, amounts are provided for the next five years only.

(c) Derivative obligations are for energy-related derivatives. For additional information, see Notes 1 and 10 to the financial statements.

(d) See Note 7 to the financial statements for additional information.

(e) The Company provides estimated capital expenditures for a five-year period, including capital expenditures associated with environmental regulations. At Dece mber 31, 2017, significant purchase commitments were outstanding in connection with the construction program. These amounts exclude capital expenditures covered under long-term service agreements, which are reflected separately. See FUTURE EARNINGS POTENTIAL – "Environmental Matters" for additional information.

(f) Fuel commitments include coal and natural gas purchases, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2017.

(g) Long-term service agreements include price escalation based on inflation indices.

(h) Purchased power represents estimated minimum long-term commitments for the purchase of solar energy. Energy costs associated with solar PPAs are recovered through the fuel clause. See Notes 3 and 7 to the financial statements for additional information.

(i) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

**Cautionary Statement Regarding Forward-Looking Statements**

The Company's 2017 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, customer and sales growth, economic conditions, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, pending or potential litigation matters, access to sources of capital, projections for the qualified pension plan and postretirement benefit plans contributions, financing activities, filings with state and federal regulatory authorities, impacts of the Tax Reform Legislation, federal income tax benefits, estimated sales and purchases under power sale and purchase agreements, storm damage cost recovery and repairs, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including environmental laws and regulations governing air, water, land, and protection of other natural resources , and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- the uncertainty surrounding the recently enacted Tax Reform Legislation, including implementing regulations and IRS interpretations, actions that may be taken in response by regulatory authorities, and its impact, if any, on the credit ratings of the Company;
- current and future litigation or regulatory investigations, proceedings, or inquiries ;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of facilities, to construct facilities in accordance with the requirements of permits and licenses , and to satisfy any environmental performance standards , including the requirements of any tax incentives;
- investment performance of the Company's employee and retiree benefit plans ;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- litigation related to the Kemper County energy facility;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or physical attack and the threat of physical attacks;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on foreign currency exchange rates, counterparty performance, and the economy in general ;
- the ability of the Company to obtain additional generating capacity (or sell excess generating capacity) at competitive prices;

- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports filed by the Company from time to time with the SEC.

**The Company expressly disclaims any obligation to update any forward-looking statements.**

**STATEMENTS OF OPERATIONS**
**For the Years Ended December 31, 2017 , 2016 , and 2015**
**Mississippi Power Company 2017 Annual Report**

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| **Operating Revenues:** | | | |
| Retail revenues | **$ 854** | $ 859 | $ 776 |
| Wholesale revenues, non-affiliates | **259** | 261 | 270 |
| Wholesale revenues, affiliates | **56** | 26 | 76 |
| Other revenues | **18** | 17 | 16 |
| Total operating revenues | **1,187** | 1,163 | 1,138 |
| **Operating Expenses:** | | | |
| Fuel | **395** | 343 | 443 |
| Purchased power | **25** | 34 | 12 |
| Other operations and maintenance | **282** | 312 | 274 |
| Depreciation and amortization | **161** | 132 | 123 |
| Taxes other than income taxes | **104** | 109 | 94 |
| Estimated loss on Kemper IGCC | **3,362** | 428 | 365 |
| Total operating expenses | **4,329** | 1,358 | 1,311 |
| **Operating Loss** | **(3,142)** | (195) | (173) |
| **Other Income and (Expense):** | | | |
| Allowance for equity funds used during construction | **72** | 124 | 110 |
| Interest expense, net of amounts capitalized | **(42)** | (74) | (7) |
| Other income (expense), net | **(8)** | (7) | (8) |
| Total other income and (expense) | **22** | 43 | 95 |
| **Loss Before Income Taxes** | **(3,120)** | (152) | (78) |
| Income taxes (benefit) | **(532)** | (104) | (72) |
| **Net Loss** | **(2,588)** | (48) | (6) |
| **Dividends on Preferred Stock** | **2** | 2 | 2 |
| **Net Loss After Dividends on Preferred Stock** | **$ (2,590)** | $ (50) | $ (8) |

The accompanying notes are an integral part of these financial statements.

**STATEMENTS OF COMPREHENSIVE INCOME (LOSS)**
**For the Years Ended December 31, 2017 , 2016 , and 2015**
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| | **2017** | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| **Net Loss** | **$ (2,588)** | $ (48) | $ (6) |
| Other comprehensive income (loss): | | | |
| Qualifying hedges: | | | |
| Changes in fair value, net of tax of $(1), $1, and $-, respectively | **(1)** | 1 | — |
| Reclassification adjustment for amounts included in net income, net of tax of $1, $1, and $1, respectively | **1** | 1 | 1 |
| Total other comprehensive income (loss) | **—** | 2 | 1 |
| **Comprehensive Loss** | **$ (2,588)** | $ (46) | $ (5) |

The accompanying notes are an integral part of these financial statements.

**STATEMENTS OF CASH FLOWS**
**For the Years Ended December 31, 2017 , 2016 , and 2015**
**Mississippi Power Company 2017 Annual Report**

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| **Operating Activities:** | | | |
| Net loss | $ (2,588) | $ (48) | $ (6) |
| Adjustments to reconcile net loss to net cash provided from operating activities — | | | |
| Depreciation and amortization, total | 198 | 157 | 126 |
| Deferred income taxes | (727) | (67) | 777 |
| Investment tax credits | — | — | (210) |
| Allowance for equity funds used during construction | (72) | (124) | (110) |
| Pension and postretirement funding | — | (47) | — |
| Regulatory assets associated with Kemper IGCC | (19) | (12) | (61) |
| Estimated loss on Kemper IGCC | 3,179 | 428 | 365 |
| Income taxes receivable, non-current | — | — | (544) |
| Other, net | (12) | (20) | 8 |
| Changes in certain current assets and liabilities — | | | |
| -Receivables | 540 | 13 | 28 |
| -Fossil fuel stock | 24 | 4 | (4) |
| -Prepaid income taxes | — | 39 | (35) |
| -Other current assets | (13) | (12) | (14) |
| -Accounts payable | (3) | (14) | (34) |
| -Accrued interest | (29) | 27 | (2) |
| -Accrued taxes | 80 | 14 | (11) |
| -Over recovered regulatory clause revenues | (51) | (45) | 96 |
| -Mirror CWIP | — | — | (271) |
| -Customer liability associated with Kemper refunds | (1) | (73) | 73 |
| -Other current liabilities | (3) | 9 | 2 |
| Net cash provided from operating activities | 503 | 229 | 173 |
| **Investing Activities:** | | | |
| Property additions | (429) | (798) | (857) |
| Construction payables | (47) | (26) | (9) |
| Government grant proceeds | — | 137 | — |
| Other investing activities | (28) | (10) | (40) |
| Net cash used for investing activities | (504) | (697) | (906) |
| **Financing Activities:** | | | |
| Decrease in notes payable, net | (18) | — | — |
| Proceeds — | | | |
| Capital contributions from parent company | 1,002 | 627 | 277 |
| Long-term debt issuance to parent company | 40 | 200 | 275 |
| Other long-term debt | — | 1,200 | — |
| Short-term borrowings | 109 | — | 505 |
| Redemptions — | | | |
| Short-term borrowings | (109) | (478) | (5) |
| Long-term debt to parent company | (591) | (225) | — |
| Capital leases | (71) | (3) | (3) |
| Senior notes | (35) | (300) | — |
| Other long-term debt | (300) | (425) | (350) |
| Other financing activities | (2) | (2) | (1) |
| Net cash provided from financing activities | 25 | 594 | 698 |
| **Net Change in Cash and Cash Equivalents** | 24 | 126 | (35) |
| **Cash and Cash Equivalents at Beginning of Year** | 224 | 98 | 133 |
| **Cash and Cash Equivalents at End of Year** | $ 248 | $ 224 | $ 98 |

**Supplemental Cash Flow Information:**

| | | | |
|---|---|---|---|
| Cash paid (received) during the period for — | | | |
| Interest (net of \$29, \$49, and \$66 capitalized, respectively) | **\$ 65** | \$ 50 | \$ 45 |
| Income taxes (net of refunds) | **(424)** | (97) | (33) |
| Noncash transactions — | | | |
| Accrued property additions at year-end | **32** | 78 | 105 |
| Issuance of promissory note to parent related to repayment of interest-bearing refundable deposits and accrued interest | **—** | — | 301 |

The accompanying notes are an integral part of these financial statements.

**BALANCE SHEETS**
**At December 31, 2017 and 2016**
**Mississippi Power Company 2017 Annual Report**

| **Assets** | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Current Assets:** | | |
| Cash and cash equivalents | **$ 248** | $ 224 |
| Receivables — | | |
| Customer accounts receivable | **36** | 29 |
| Unbilled revenues | **41** | 42 |
| Income taxes receivable, current | **4** | 544 |
| Affiliated | **16** | 15 |
| Other accounts and notes receivable | **12** | 14 |
| Fossil fuel stock | **17** | 100 |
| Materials and supplies, current | **44** | 76 |
| Other regulatory assets, current | **125** | 115 |
| Other current assets | **9** | 8 |
| Total current assets | **552** | 1,167 |
| **Property, Plant, and Equipment:** | | |
| In service | **4,773** | 4,865 |
| Less: Accumulated provision for depreciation | **1,325** | 1,289 |
| Plant in service, net of depreciation | **3,448** | 3,576 |
| Construction work in progress | **84** | 2,545 |
| Total property, plant, and equipment | **3,532** | 6,121 |
| **Other Property and Investments** | **30** | 12 |
| **Deferred Charges and Other Assets:** | | |
| Deferred charges related to income taxes | **35** | 361 |
| Other regulatory assets, deferred | **437** | 518 |
| Accumulated deferred income taxes | **247** | — |
| Other deferred charges and assets | **33** | 56 |
| Total deferred charges and other assets | **752** | 935 |
| **Total Assets** | **$ 4,866** | $ 8,235 |

The accompanying notes are an integral part of these financial statements.

**BALANCE SHEETS**
**At December 31, 2017 and 2016**
**Mississippi Power Company 2017 Annual Report**

| **Liabilities and Stockholder's Equity** | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Current Liabilities:** | | |
| Securities due within one year — | | |
| Parent | **$ —** | $ 551 |
| Other | **989** | 78 |
| Notes payable | **4** | 23 |
| Accounts payable — | | |
| Affiliated | **59** | 62 |
| Other | **96** | 135 |
| Accrued taxes — | | |
| Accrued income taxes | **40** | — |
| Other accrued taxes | **101** | 99 |
| Unrecognized tax benefits | **—** | 383 |
| Accrued interest | **16** | 46 |
| Accrued compensation | **39** | 42 |
| Asset retirement obligations, current | **37** | 32 |
| Over recovered regulatory clause liabilities | **—** | 51 |
| Other current liabilities | **82** | 36 |
| Total current liabilities | **1,463** | 1,538 |
| **Long-Term Debt** ( See accompanying statements ) | **1,097** | 2,424 |
| **Deferred Credits and Other Liabilities:** | | |
| Accumulated deferred income taxes | **—** | 756 |
| Deferred credits related to income taxes | **372** | 7 |
| Employee benefit obligations | **116** | 115 |
| Asset retirement obligations, deferred | **137** | 146 |
| Other cost of removal obligations | **178** | 170 |
| Other regulatory liabilities, deferred | **79** | 77 |
| Other deferred credits and liabilities | **33** | 26 |
| Total deferred credits and other liabilities | **915** | 1,297 |
| **Total Liabilities** | **3,475** | 5,259 |
| **Cumulative Redeemable Preferred Stock** ( See accompanying statements ) | **33** | 33 |
| **Common Stockholder's Equity** ( See accompanying statements ) | **1,358** | 2,943 |
| **Total Liabilities and Stockholder's Equity** | **$ 4,866** | $ 8,235 |
| **Commitments and Contingent Matters** ( See notes ) | | |

The accompanying notes are an integral part of these financial statements.

**STATEMENTS OF CAPITALIZATION**
**At December 31, 2017 and 2016**
**Mississippi Power Company 2017 Annual Report**

| | 2017 | 2016 | 2017 | 2016 |
|---|---|---|---|---|
| | *(in millions)* | | *(percent of total)* | |
| **Long-Term Debt:** | | | | |
| Long-term notes payable — | | | | |
| 5.60% due 2017 | $ — | $ 35 | | |
| 1.63% due 2018 | **50** | 50 | | |
| 5.55% due 2019 | **125** | 125 | | |
| 4.25% to 5.40% due 2035-2042 | **630** | 630 | | |
| Adjustable rate (3.05% at 12/31/17) due 2018 | **900** | 1,200 | | |
| Total long-term notes payable | **1,705** | 2,040 | | |
| Other long-term debt — | | | | |
| Pollution control revenue bonds — | | | | |
| 5.15% due 2028 | **43** | 43 | | |
| Variable rates (2.45% to 2.50% at 12/31/17) due 2018 | **40** | 40 | | |
| Plant Daniel revenue bonds (7.13%) due 2021 | **270** | 270 | | |
| Long-term debt payable to parent company (2.27%) due 2017 | — | 551 | | |
| Total other long-term debt | **353** | 904 | | |
| Capitalized lease obligations | — | 74 | | |
| Unamortized debt premium | **36** | 45 | | |
| Unamortized debt discount | **(1)** | (2) | | |
| Unamortized debt issuance expense | **(7)** | (8) | | |
| Total long-term debt (annual interest requirement — $86 million) | **2,086** | 3,053 | | |
| Less amount due within one year | **989** | 629 | | |
| Long-term debt excluding amount due within one year | **1,097** | 2,424 | **44.1%** | 44.9% |
| **Cumulative Redeemable Preferred Stock:** | | | | |
| $100 par value — | | | | |
| Authorized — 1,244,139 shares | | | | |
| Outstanding — 334,210 shares | | | | |
| 4.40% to 5.25% (annual dividend requirement — $2 million) | **33** | 33 | **1.3** | 0.6 |
| **Common Stockholder's Equity:** | | | | |
| Common stock, without par value — | | | | |
| Authorized — 1,130,000 shares | | | | |
| Outstanding — 1,121,000 shares | **38** | 38 | | |
| Paid-in capital | **4,529** | 3,525 | | |
| Accumulated deficit | **(3,205)** | (616) | | |
| Accumulated other comprehensive loss | **(4)** | (4) | | |
| Total common stockholder's equity | **1,358** | 2,943 | **54.6** | 54.5 |
| **Total Capitalization** | **$ 2,488** | $ 5,400 | **100.0%** | 100.0% |

The accompanying notes are an integral part of these financial statements.

**STATEMENTS OF COMMON STOCKHOLDER'S EQUITY**
**For the Years Ended December 31, 2017 , 2016 , and 2015**
**Mississippi Power Company 2017 Annual Report**

| | Number of Common Shares Issued | Common Stock | Paid-In Capital | Retained Earnings (Accumulated Deficit) | Accumulated Other Comprehensive Income (Loss) | Total |
|---|---|---|---|---|---|---|
| | | | | *(in millions)* | | |
| **Balance at December 31, 2014** | 1 | $ 38 | $ 2,612 | $ (559) | $ (7) | $ 2,084 |
| Net loss after dividends on preferred stock | — | — | — | (8) | — | (8) |
| Capital contributions from parent company | — | — | 281 | — | — | 281 |
| Other comprehensive income (loss) | — | — | — | — | 1 | 1 |
| Other | — | — | — | 1 | — | 1 |
| **Balance at December 31, 2015** | 1 | 38 | 2,893 | (566) | (6) | 2,359 |
| Net loss after dividends on preferred stock | — | — | — | (50) | — | (50) |
| Capital contributions from parent company | — | — | 632 | — | — | 632 |
| Other comprehensive income (loss) | — | — | — | — | 2 | 2 |
| **Balance at December 31, 2016** | **1** | **38** | **3,525** | **(616)** | **(4)** | **2,943** |
| Net loss after dividends on preferred stock | **—** | **—** | **—** | **(2,590)** | **—** | **(2,590)** |
| Capital contributions from parent company | **—** | **—** | **1,004** | **—** | **—** | **1,004** |
| Other | **—** | **—** | **—** | **1** | **—** | **1** |
| **Balance at December 31, 2017** | **1** | **$ 38** | **$ 4,529** | **$ (3,205)** | **$ (4)** | **$ 1,358** |

The accompanying notes are an integral part of these financial statements.

**NOTES TO FINANCIAL STATEMENTS**
**Mississippi Power Company 2017 Annual Report**

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**NOTES (continued)**
**Mississippi Power Company 2017 Annual Report**

## 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

### General

Mississippi Power Company (the Company) is a wholly-owned subsidiary of Southern Company, which is the parent company of the Company and three other traditional electric operating companies, as well as Southern Power, Southern Company Gas (as of July 1, 2016), SCS, Southern Linc, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, PowerSecure, Inc. (PowerSecure) (as of May 9, 2016), and other direct and indirect subsidiaries. The traditional electric operating companies – Alabama Power, Georgia Power, Gulf Power, and the Company – are vertically integrated utilities providing electric service in four Southeastern states. The Company provides electric service to retail customers in southeast Mississippi and to wholesale customers in the Southeast. Southern Power develops, constructs, acquires, owns, and manages power generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Company Gas distributes natural gas through utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. Southern Linc provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber optics services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases and for other electric services. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants. PowerSecure is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure.

The Company is subject to regulation by the FERC and the Mississippi PSC. As such, the Company's financial statements reflect the effects of rate regulation in accordance with GAAP and comply with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

### Recently Issued Accounting Standards

***Revenue***

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers* (ASC 606), replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the new standard is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

Most of the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term , as well as longer-term contractual commitments, including PPAs.

The Company has completed the evaluation of all revenue streams and determined that the adoption of ASC 606 will not change the current timing of revenue recognition for such transactions. Some revenue arrangements, such as energy-related derivatives and alternative revenue programs, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed or presented separately from revenues under ASC 606 on the Company's financial statements, if material. The Company has concluded contributions in aid of construction are not in scope for ASC 606 and will continue to be accounted for as an offset to property, plant, and equipment.

The new standard is effective for reporting periods beginning after December 15, 2017. The Company applied the modified retrospective method of adoption effective January 1, 2018. The Company also utilized practical expedients which allowed it to apply the standard to open contracts at the date of adoption and to reflect the aggregate effect of all modifications when identifying performance obligations and allocating the transaction price for contracts modified before the effective date. Under the modified retrospective method of adoption, prior year reported results are not restated; however, a cumulative-effect adjustment to retained earnings at January 1, 2018 is recorded. In addition, quarterly disclosures will include comparative information on 2018 financial statement line items under current guidance. The adoption of ASC 606 did not result in a cumulative-effect adjustment .

***Leases***

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged . ASU 2016-02 is effective for fiscal years beginning after December 15, 2018 and the Company will adopt the new standard effective January 1, 2019.

The Company is currently implementing an information technology system along with the related changes to internal controls and accounting policies that will support the accounting for leases under ASU 2016-02. In addition, the Company has substantially completed a detailed inventory and analysis of its leases. In terms of rental charges and duration of contracts, the most significant leases relate to equipment and cellular towers where the Company is the lessee and to equipment where the Company is the lessor. The Company is currently analyzing pole attachment agreements and a lease determination has not been made at this time. While the Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

***Other***

In March 2016, the FASB issued ASU No. 2016-09, *Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Notes 5 and 8 for disclosures impacted by ASU 2016-09.

On March 10, 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017-07). ASU 2017-07 requires that an employer report the service cost component in the same line item or items as other compensation costs and requires the other components of net periodic pension and postretirement benefit costs to be separately presented in the income statement outside of income from operations. Additionally, only the service cost component is eligible for capitalization, when applicable. However, all cost components remain eligible for capitalization under FERC regulations. ASU 2017-07 will be applied retrospectively for the presentation of the service cost component and the other components of net periodic pension and postretirement benefit costs in the income statement. The capitalization of only the service cost component of net periodic pension and postretirement benefit costs in assets will be applied on a prospective basis. ASU 2017-07 is effective for periods beginning after December 15, 2017. The presentation changes required for net periodic pension and postretirement benefit costs will result in a decrease in the Company's operating income and an increase in other income for 2016 and 2017 and are expected to result in a decrease in operating income and an increase in other income for 2018. The Company adopted ASU 2017-07 effective January 1, 2018 with no material impact on its financial statements.

On August 28, 2017, the FASB issued ASU No. 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities* (ASU 2017-12), amending the hedge accounting recognition and presentation requirements. ASU 2017-12 makes more financial and non-financial hedging strategies eligible for hedge accounting, amends the related presentation and disclosure requirements, and simplifies hedge effectiveness assessment requirements. ASU 2017-12 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

**Affiliate Transactions**

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations, construction management, and power pool transactions. Costs for these services amounted to $140 million , $231 million , and $295 million during 2017 , 2016 , and 2015 , respectively. Cost allocation methodologies used by SCS prior to the repe al of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies. See Note 7 under "Operating Leases" for additional information.

The Company has an agreement with Alabama Power under which the Company owns a portion of Greene County Steam Plant. Alabama Power operates Greene Coun ty Steam Plant, and the Company reimburses Alabama Power for its proportionate share of non-fuel expenditures and costs, which totaled $9 million , $13 million , and $11 million in 2017 , 2016 , and 2015 , respectively. Also, the Company reimburses Alabama Power for any direct fuel purchases delivered from an Alabama Power transfer facility. There were no fuel purchases in 2017 or 2016 . Fuel purchases were $8 million in 2015 . The Company also has an agreement with Gulf Power under which Gulf Power owns a portion of Plant Daniel. The Company operates Plant Daniel, and Gulf Power reimburses the Company for its proportionate share of all associated expenditures and costs, whic h totaled $31 million , $26 million , and $27 million in 2017 , 2016 , and 2015 , respectively. See Note 4 for additional information.

Total power purchased from affiliates through the power pool, included in purchased power in the statement of operations, totaled $16 million , $29 million , and $7 million in 2017 , 2016 , and 2015 , respectively.

In June 2017, the Company received a capital contribution from Southern Company of $1.0 billion . The Company used a portion of the proceeds to repay all of the $591 million outstanding principal amount of promissory notes to Southern Company. See Note 6 for additional information.

On September 15, 2017, the Company issued a floating rate promissory note to Southern Company in an aggregate principal amount of up to $150 million bearing interest based on one-month LIBOR. The Company borrowed $109 million under this promissory note primarily to satisfy its federal income tax obligations for the quarter ending September 30, 2017 and subsequently repaid the promissory note upon receipt of its income tax refund from the U.S. federal government related to the settlement concerning deductible research and experimental (R&E) expenditures. See Note 5 under "Section 174 Research and Experimental Deduction" for additional information.

The Company also provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described he rein, the Company neither provided nor received any material services to or from affiliates in 2017 , 2016 , or 2015 .

The traditional electric operating companies, including the Company, and S outhern Power may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS, as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

**Regulatory Assets and Liabilities**

The Company is subject to accounting requirements for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

**NOTES (continued)**
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Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

| | 2017 | 2016 | Note |
|---|---|---|---|
| | | *(in millions)* | |
| Retiree benefit plans – regulatory assets | **$ 174** | $ 173 | (a) |
| Asset retirement obligations | **95** | 83 | (b) |
| Kemper County energy facility | **88** | 194 | (c) |
| Remaining net book value of retired assets | **44** | 53 | (d) |
| Property tax | **43** | 37 | (e) |
| Deferred charges related to income taxes | **36** | 362 | (d) |
| Plant Daniel Units 3 and 4 | **36** | 33 | (f) |
| Other regulatory assets | **28** | 28 | (g) |
| ECO carryforward | **26** | 22 | (h) |
| Other regulatory liabilities | **—** | (1) | (i) |
| Deferred credits related to income taxes | **(377)** | (9) | (j) |
| Other cost of removal obligations | **(178)** | (170) | (k) |
| Property damage | **(57)** | (68) | (l) |
| Total regulatory assets (liabilities), net | **$ (42)** | $ 737 | |

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Recovered and amortized over the average remaining service period which may range up to 15 years . See Note 2 for additional information.

(b) To be recovered upon completion of removal activities over a period approved by the Mississippi PSC.

(c) Includes $114 million of regulatory assets and $26 million of regulatory liabilities to be recovered in rates over periods of eight and six years, respectively. For additional information, see Note 3 under "Kemper County Energy Facility – Rate Recovery – Kemper Settlement Agreement."

(d) Recovered over the related property lives up to 48 years.

(e) Recovered through the ad valorem tax adjustment clause over a 12 -month period beg inning in April of the following year. See Note 3 under "Retail Regulatory Matters – Ad Valorem Tax Adjustment" for additional information.

(f) Represents the difference between the revenue requirement under the purchase option and the revenue requirement assuming operating lease accounting treatment for the extended term, which will be amortized over a 10 -year period beginning October 2021.

(g) Comprised of vacation pay, loss on reacquired debt, and other miscellaneous assets. These costs are recorded and recovered or amortized as approved by the Mississippi PSC over periods which may range up to 50 years. This amount also includes fuel-hedging assets and liabilities which are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed three years. Upon final settlement, actual costs incurred are recovered through the ECM.

(h) Recovered through the ECO clause in the year following the deferral.

(i) Comprised of numerous immaterial components including deferred income tax credits and other miscellaneous liabilities that are recorded and refunded or amortized as approved by the Mississippi PSC generally over periods not exceeding one year.

(j) This amount includes excess deferred income taxes primarily associated with Tax Reform Legislation of $375 million , of which $273 million is related to protected deferred income taxes to be recovered over the related property lives utilizing the average rate assumption method in accordance with IRS normalization principles and $102 million related to unprotected (not subject to normalization) deferred income taxes to be amortized over a period approved by the Mississippi PSC or the FERC, as appropriate. Of the total excess deferred income taxes associated with Tax Reform Legislation, $129 million is associated with the Kemper County energy facility. The unprotected portion associated with the Kemper County energy facility is $54 million , of which $38 million is being amortized over eight years for retail as approved by the Mississippi PSC on February 6, 2018 and $16 million is wholesale-related. Currently, the Company is requesting eight -year amortization for the remaining portions of the unprotected deferred income taxes associated with Tax Reform Legislation in all of its retail and wholesale rate filings. See Note 3 under "Retail Regulatory Matters" and "Kemper County Energy Facility" and Note 5 for additional information.

(k) Collected in advance from customers to remove assets upon their retirement.

(l) For additional information, see Note 1 under "Provision for Property Damage."

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated OCI related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" and "Kemper County Energy Facility" for additional information.

**Government Grants**

In 2010, the DOE, through a cooperative agreement with SCS, agreed to fund $270 million of the Kemper County energy facility through the grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (Initial DOE Grants). Through December 31, 2017 , the Company has received grant funds of $382 million , of which $245 million of the Initial DOE Grants were used for the construction of the Kemper County energy facility, which is reflected in the Company's financial statements as a reduction to the Kemper County energy facility capital costs, and $137 million received on April 8, 2016 (Additional DOE Grants), which are expected to be used to reduce future rate impacts. An additional $2 million is expected to be received for allowable costs through December 31, 2017. See Note 3 under "Kemper County Energy Facility – Schedule and Cost Estimate" for additional information.

**Revenues**

Energy and other revenues are recognized as services are provided. Wholesale capacity revenues from long-term contracts are recognized at the lesser of the levelized amount or the amount billable under the contract over the respective contract period. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. The Company's retail and wholesale rates include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Retail rates also include provisions to adjust billings for fluctuations in costs for ad valorem taxes and certain qualifying environmental costs. Revenues are adjusted for differences between these actual costs and projected amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company is required to file with the Mississippi PSC for an adjustment to the fuel cost recovery, ad valorem, and environmental factors annually.

The Company serves long-term contracts with rural electric cooperative associations and municipalities located in southeastern Mississippi under cost-based MRA electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represent ed 19.3% of the Company's total operating revenues in 2017 and are largely subject to rolling 10 -year c ancellation notices. Historically, these wholesale customers have acted as a group and any changes in contractual relationships for one customer are likely to be followed by the other wholesale customers.

Except as described above for the Company's cost-based MRA electric tariff customers, the Company has a diversified base of customers and no single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

See Note 3 under "Retail Regulatory Matters" for additional information.

**Fuel Costs**

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel costs also include gains and/or losses from fuel-hedging programs as approved by the Mississippi PSC.

**Income and Other Taxes**

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. ITCs utilized are deferred and amortized to income over the average life of the related property. T axes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of operations.

The Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

**Property, Plant, and Equipment**

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and cost of equity funds used during construction for projects where recovery of CWIP is not allowed in rates.

The Company's property, plant, and equipment in service consisted of the following at December 31:

| | | 2017 | | 2016 |
|---|---|---|---|---|
| | | *(in millions)* | | |
| Generation | $ | **2,801** | $ | 2,632 |
| Transmission | | **737** | | 712 |
| Distribution | | **946** | | 916 |
| General | | **204** | | 520 |
| Plant acquisition adjustment | | **85** | | 85 |
| Total plant in service | $ | **4,773** | $ | 4,865 |

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses except for a portion of the railway track maintenance costs. The portion of railway track maintenance costs not charged to operations and maintenance expenses are charged to fuel stock and recovered through the Company's fuel clause.

**Depreciation, Depletion, and Amortization**

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.7% in 2017 , 4.2% in 2016 , and 4.7% in 2015 . The decrease in 2017 is primarily due to lower depreciation expense as a result of recording a loss on the lignite mine in June 2017. The decrease in the 2016 depreciation rate is primarily due to fully depreciating and retiring the ARO at Plant Watson, partially offset by the increase in depreciation for the Plant Daniel scrubbers for a full year. See "Asset Retirement Obligations and Other Costs of Removal" herein for additional information. Depreciation studies are conducted periodically to update the composite rates. The Mississippi PSC approved the 2014 study, with new rates effective January 1, 2015. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. Depreciation includes an amount for the expected cost of removal of facilities, except for the Kemper County energy facility combined cycle and related assets in service.

**Asset Retirement Obligations and Other Costs of Removal**

AROs are computed as the present value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities. The Company has received accounting guidance from the Mississippi PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The liability for AROs primarily relates to facilities that are subject to the Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA in 2015 (CCR Rule), principally ash ponds. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, deep injection wells, water wells, substation removal, mine reclamation, and asbestos removal. The Company also has identified AROs related to certain transmission and distribution facilities and certain wireless communication towers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the AROs related to these assets is indeterminable and, therefore, the fair value of the AROs cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. The Company will continue to recognize in th e statements of operations allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as e ither a regulatory asset or liability, as ordered by the Mississippi PSC, and are reflected in the balance sheets.

**NOTES (continued)**
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Details of the AROs included in the balance sheets are as follows:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| Balance at beginning of year | **$ 179** | $ 177 |
| Liabilities incurred | **—** | 15 |
| Liabilities settled | **(23)** | (23) |
| Accretion | **5** | 5 |
| Cash flow revisions | **13** | 5 |
| Balance at end of year | **$ 174** | $ 179 |

The increase in cash flow revisions in 2017 is primarily related to a revision in the closure date of the lignite mine ARO.

The cost estimates for AROs related to the CCR Rule are based on information as of December 31, 2017 using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure. As further analysis is performed and closure details are developed, the Company will continue to periodically update these cost estimates as necessary.

**Allowance for Funds Used During Construction**

The Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently, AFUDC increases the revenue requirement and is recovered over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in the calculation of taxable income. The average annual AFUDC rate was 6.7% , 6.5% , and 5.99% for the years ended December 31, 2017 , 2016 , and 2015 , respectively. AFUDC equity was $72 million , $124 million , a nd $110 million in 2017 , 2016 , and 2015 , respectively. The decrease in 2017 resulted from the Kemper IGCC project suspension in June 2017.

**Impairment of Long-Lived Assets and Intangibles**

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

**Provision for Property Damage**

The Company carries insurance for the cost of certain types of damage to generation plants and general property. However, the Company is self-insured for the cost of storm, fire, and other uninsured casualty damage to its property, including transmission and distribution facilities. As permitted by the Mississippi PSC and the FERC, the Company accrues for the cost of such damage through an annual expense accrual credited to regulatory liability accounts for the retail and wholesale jurisdictions. The cost of repairing actual damage resulting from such events that individually exce ed $50,000 i s charged to the reserve. Every three years the Mississippi PSC, the MPUS, and the Company will agree on SRR revenue level(s) for the ensuing period, based on historical data, expected exposure, type and amount of insurance coverage, excluding insurance cost, and any other relevant information. The accrual amount and the reserve balance are determined based on the SRR revenue level(s). If a significant change in circumstances occurs, then the SRR revenue level can be adjusted more frequently if the Company and the MPUS or the Mississippi PSC deem the change appropriate. The property damage reserve accrual will be the difference between the approved SRR revenues and the SRR revenue requirement, excluding any accrual to the reserve. In addition, SRR allows the Company to set up a regulatory asset, pending review, if the allowable actual retail property damage costs exceed the amount in the retail property damage reserve. The Company made retail accruals of $3 million , $4 million , and $3 million for 2017 , 2016 , and 2015 , respectively. The Company also accrued $0.3 million annually in 2017 , 2016 , and 2015 for the wholesale jurisdiction. As of December 31, 2017 , the property damage reserve balances were $56 million and $1 million for retail and wholesa le, respectively.

**Cash and Cash Equivalents**

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

**Materials and Supplies**

Generally, materials and supplies include the average cost of transmission, distribution, mining, and generating plant materials. Materials are charged to inventory when purchased and then expensed, capitalized to plant, or charged to fuel stock, as used, at weighted-average cost when utilized.

**Fuel Inventory**

Fuel inventory includes the average cost of coal, natural gas, oil, transportation, and emissions allowances. Fuel costs are recorded to inventory when purchased, and then expensed, at weighted average cost, as used and recovered by the Company through fuel cost recovery rates. The retail rate is approved by the Mississippi PSC and the wholesale rates are approved by the FERC. Emissions allowances granted by the EPA are included in inventory at zero cost.

**Financial Instruments**

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities on the balance sheets (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 9 for additional information regarding fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from the fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Fuel and interest rate derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the Mississippi PSC approved fuel-hedging program as discussed below result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded on a net basis in the statements of operations. Cash flows from d erivatives are classified on the statement of cash flows in the same category as the hedged item. See Note 10 for additional information regarding derivatives.

The Company offsets fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a netting arrangement. Additionally, the Company's collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2017 are immaterial.

The Company has an ECM clause which, among other things, allows the Company to utilize financial instruments to hedge its fuel commitments. Changes in the fair value of these financial instruments are recorded as regulatory assets or liabilities. Amounts paid or received as a result of financial settlement of these instruments are classified as fuel expense and are included in the ECM factor applied to customer billings. The Company's jurisdictional wholesale customers have a similar ECM mechanism, which has been approved by the FERC.

The Company is exposed to potential losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

**Comprehensive Income**

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts included in net income.

**Variable Interest Entities**

The primary beneficiary of a variable interest entity (VIE) is required to consolidate the VIE when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE.

The Company was required to provide financing for all costs associated with the mine development and operation under a contract with Liberty Fuels Company, LLC, a subsidiary of North American Coal Corporation (Liberty Fuels), in conjunction with the construction of the Kemper County energy facility. Liberty Fuels qualified as a VIE for which the Company was the primary beneficiary. As of December 31, 2016, the VIE consolidation resulted in an ARO asset and associated liability in the amounts of $20 million and $24 million , respectively. As of December 31, 2017, the VIE consolidation resulted in an ARO liability in the amount of $38 million . The associated ARO asset was included as part of an additional charge to income in 2017 as a result of the Company's assessment of the probability of disallowance by the Mississippi PSC. See Note 3 under "Kemper County Energy Facility" for additional information.

## 2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2017 and no mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2018 . The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the FERC. For the year ending December 31, 2018 , no other postretirement trust contributions are expected.

**Actuarial Assumptions**

The weighted average rates assumed in the actuarial calculations used to determine both the net periodic costs for the pension and other postretirement benefit plans for the following year and the benefit obligations as of the measurement date are presented below.

| Assumptions used to determine net periodic costs: | 2017 | 2016 | 2015 |
|---|---|---|---|
| **Pension plans** | | | |
| Discount rate – benefit obligations | **4.44%** | 4.69% | 4.17% |
| Discount rate – interest costs | **3.81** | 3.97 | 4.17 |
| Discount rate – service costs | **4.83** | 5.04 | 4.49 |
| Expected long-term return on plan assets | **7.95** | 8.20 | 8.20 |
| Annual salary increase | **4.46** | 4.46 | 3.59 |
| **Other postretirement benefit plans** | | | |
| Discount rate – benefit obligations | **4.22%** | 4.47% | 4.03% |
| Discount rate – interest costs | **3.55** | 3.66 | 4.03 |
| Discount rate – service costs | **4.65** | 4.88 | 4.38 |
| Expected long-term return on plan assets | **6.88** | 7.07 | 7.23 |
| Annual salary increase | **4.46** | 4.46 | 3.59 |

| Assumptions used to determine benefit obligations: | 2017 | 2016 |
|---|---|---|
| **Pension plans** | | |
| Discount rate | **3.80%** | 4.44% |
| Annual salary increase | **4.46** | 4.46 |
| **Other postretirement benefit plans** | | |
| Discount rate | **3.68%** | 4.22% |
| Annual salary increase | **4.46** | 4.46 |

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of eight different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2017 were as follows:

| | Initial Cost Trend Rate | Ultimate Cost Trend Rate | Year That Ultimate Rate is Reached |
|---|---|---|---|
| Pre-65 | 6.50% | 4.50% | 2026 |
| Post-65 medical | 5.00 | 4.50 | 2026 |
| Post-65 prescription | 10.00 | 4.50 | 2026 |

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2017 as follows:

| | 1 Percent Increase | 1 Percent Decrease |
|---|---|---|
| | *(in millions)* | |
| Benefit obligation | $ 5 | $ 5 |
| Service and interest costs | — | — |

**Pension Plans**

The total accumulated benefit obligation for the pension plans was $541 million at December 31, 2017 and $479 million at December 31, 2016 . Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2017 and 2016 were as follows:

| | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Change in benefit obligation** | | |
| Benefit obligation at beginning of year | **$ 534** | $ 500 |
| Service cost | **15** | 13 |
| Interest cost | **20** | 19 |
| Benefits paid | **(22)** | (20) |
| Actuarial (gain) loss | **55** | 22 |
| Balance at end of year | **602** | 534 |
| **Change in plan assets** | | |
| Fair value of plan assets at beginning of year | **499** | 430 |
| Actual return (loss) on plan assets | **84** | 39 |
| Employer contributions | **2** | 50 |
| Benefits paid | **(22)** | (20) |
| Fair value of plan assets at end of year | **563** | 499 |
| Accrued liability | **$ (39)** | $ (35) |

At December 31, 2017 , the projected benefit obligations for the qualified and non-qualified pension plans were $571 million and $31 million , respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2017 and 2016 related to the Company's pension plans consist of the following:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| Other regulatory assets, deferred | $ 158 | $ 154 |
| Other current liabilities | (3) | (3) |
| Employee benefit obligations | (36) | (32) |

Presented below are the amounts included in regulatory assets at December 31, 2017 and 2016 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2018 .

| | 2017 | 2016 | Estimated Amortization in 2018 |
|---|---|---|---|
| | | *(in millions)* | |
| Prior service cost | $ 3 | $ 3 | $ — |
| Net (gain) loss | 155 | 151 | 10 |
| Regulatory assets | $ 158 | $ 154 | |

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2017 and 2016 are presented in the following table:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Regulatory assets:** | | |
| Beginning balance | $ 154 | $ 144 |
| Net (gain) loss | 12 | 16 |
| Change in prior service costs | — | 2 |
| Reclassification adjustments: | | |
| Amortization of prior service costs | (1) | (1) |
| Amortization of net gain (loss) | (7) | (7) |
| Total reclassification adjustments | (8) | (8) |
| Total change | 4 | 10 |
| Ending balance | $ 158 | $ 154 |

Components of net periodic pension cost were as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| Service cost | $ 15 | $ 13 | $ 13 |
| Interest cost | 20 | 19 | 21 |
| Expected return on plan assets | (40) | (35) | (33) |
| Recognized net (gain) loss | 7 | 7 | 10 |
| Net amortization | 1 | 1 | 1 |
| Net periodic pension cost | $ 3 | $ 5 | $ 12 |

Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2017 , estimated benefit payments were as follows:

| | Benefit Payments |
|---|---|
| | *(in millions)* |
| 2018 | $ 23 |
| 2019 | 24 |
| 2020 | 26 |
| 2021 | 27 |
| 2022 | 28 |
| 2023 to 2027 | 164 |

**Other Postretirement Benefits**

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2017 and 2016 were as follows:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Change in benefit obligation** | | |
| Benefit obligation at beginning of year | **$ 97** | $ 97 |
| Service cost | **1** | 1 |
| Interest cost | **3** | 3 |
| Benefits paid | **(6)** | (6) |
| Actuarial (gain) loss | **1** | 1 |
| Retiree drug subsidy | **1** | 1 |
| Balance at end of year | **97** | 97 |
| **Change in plan assets** | | |
| Fair value of plan assets at beginning of year | **23** | 23 |
| Actual return (loss) on plan assets | **3** | 1 |
| Employer contributions | **4** | 4 |
| Benefits paid | **(5)** | (5) |
| Fair value of plan assets at end of year | **25** | 23 |
| Accrued liability | **$ (72)** | $ (74) |

Amounts recognized in the balance sheets at December 31, 2017 and 2016 related to the Company's other postretirement benefit plans consist of the following:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| Other regulatory assets, deferred | **$ 18** | $ 21 |
| Other regulatory liabilities, deferred | **(1)** | (2) |
| Employee benefit obligations | **(72)** | (74) |

**NOTES (continued)**
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Approximately $17 million and $19 million was included in net regulatory assets at December 31, 2017 and 2016 , respectively, related to the net loss for the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost. The estimated amortization of such amounts for 2018 is $1 million .

The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2017 and 2016 are presented in the following table:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Net regulatory assets (liabilities):** | | |
| Beginning balance | $ 19 | $ 18 |
| Net (gain) loss | (1) | 2 |
| Reclassification adjustments: | | |
| Amortization of net gain (loss) | (1) | (1) |
| Total reclassification adjustments | (1) | (1) |
| Total change | (2) | 1 |
| Ending balance | $ 17 | $ 19 |

Components of the other postretirement benefit plans' net periodic cost were as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| Service cost | $ 1 | $ 1 | $ 1 |
| Interest cost | 3 | 3 | 4 |
| Expected return on plan assets | (1) | (1) | (2) |
| Net amortization | 1 | 1 | 1 |
| Net periodic postretirement benefit cost | $ 4 | $ 4 | $ 4 |

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

| | Benefit Payments | Subsidy Receipts | Total |
|---|---|---|---|
| | | *(in millions)* | |
| 2018 | $ 6 | $ — | $ 6 |
| 2019 | 6 | — | 6 |
| 2020 | 6 | (1) | 5 |
| 2021 | 7 | (1) | 6 |
| 2022 | 7 | (1) | 6 |
| 2023 to 2027 | 34 | (2) | 32 |

**Benefit Plan Assets**

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

**NOTES (continued)**
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The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2017 and 2016 , along with the targeted mix of assets for each plan, is presented below:

| | Target | **2017** | 2016 |
|---|---|---|---|
| **Pension plan assets:** | | | |
| Domestic equity | 26% | **31%** | 29% |
| International equity | 25 | **25** | 22 |
| Fixed income | 23 | **24** | 29 |
| Special situations | 3 | **1** | 2 |
| Real estate investments | 14 | **13** | 13 |
| Private equity | 9 | **6** | 5 |
| Total | 100% | **100%** | 100% |
| **Other postretirement benefit plan assets:** | | | |
| Domestic equity | 21% | **25%** | 23% |
| International equity | 21 | **20** | 18 |
| Domestic fixed income | 37 | **38** | 43 |
| Special situations | 2 | **1** | 2 |
| Real estate investments | 12 | **11** | 10 |
| Private equity | 7 | **5** | 4 |
| Total | 100% | **100%** | 100% |

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns and interest rates, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices. Management believes the portfolio is well-diversified with no significant concentrations of risk.

***Investment Strategies***

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

***Benefit Plan Asset Fair Values***

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2017 and 2016 . The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- ***Domestic and international equity.*** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- ***Fixed income.*** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- ***Real estate investments, private equity, and special situations investments.*** Investments in real estate, private equity, and special situations are generally classified as Net Asset Value as a Practical Expedient, since the underlying assets typically do not have publicly available observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. Techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, discounted cash flow analysis, prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals. The fair value of partnerships is determined by aggregating the value of the underlying assets less liabilities.

The fair values of pension plan assets as of December 31, 2017 and 2016 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| **As of December 31, 2017:** | **Quoted Prices in Active Markets for Identical Assets (Level 1)** | **Significant Other Observable Inputs (Level 2)** | **Significant Unobservable Inputs (Level 3)** | **Net Asset Value as a Practical Expedient (NAV)** | **Total** |
| | | | *(in millions)* | | |
| Assets: | | | | | |
| Domestic equity (*) | $ 113 | $ 55 | $ — | $ — | $ 168 |
| International equity (*) | 73 | 66 | — | — | 139 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 40 | — | — | 40 |
| Corporate bonds | — | 56 | — | — | 56 |
| Pooled funds | — | 31 | — | — | 31 |
| Cash equivalents and other | 10 | 1 | — | — | 11 |
| Real estate investments | 22 | — | — | 56 | 78 |
| Special situations | — | — | — | 9 | 9 |
| Private equity | — | — | — | 32 | 32 |
| Total | $ 218 | $ 249 | $ — | $ 97 | $ 564 |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

**NOTES (continued)**
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| As of December 31, 2016: | Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Net Asset Value as a Practical Expedient (NAV) | Total |
|---|---|---|---|---|---|
| | | | *(in millions)* | | |
| Assets: | | | | | |
| Domestic equity (*) | $ 95 | $ 44 | $ — | $ — | $ 139 |
| International equity (*) | 58 | 51 | — | — | 109 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 28 | — | — | 28 |
| Mortgage- and asset-backed securities | — | 1 | — | — | 1 |
| Corporate bonds | — | 46 | — | — | 46 |
| Pooled funds | — | 25 | — | — | 25 |
| Cash equivalents and other | 47 | — | — | — | 47 |
| Real estate investments | 15 | — | — | 54 | 69 |
| Special situations | — | — | — | 8 | 8 |
| Private equity | — | — | — | 26 | 26 |
| Total | $ 215 | $ 195 | $ — | $ 88 | $ 498 |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

The fair values of other postretirement benefit plan assets as of December 31, 2017 and 2016 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

| As of December 31, 2017: | Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Net Asset Value as a Practical Expedient (NAV) | Total |
|---|---|---|---|---|---|
| | | | *(in millions)* | | |
| Assets: | | | | | |
| Domestic equity (*) | $ 4 | $ 2 | $ — | $ — | $ 6 |
| International equity (*) | 3 | 2 | — | — | 5 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 5 | — | — | 5 |
| Corporate bonds | — | 2 | — | — | 2 |
| Pooled funds | — | 1 | — | — | 1 |
| Cash equivalents and other | 1 | — | — | — | 1 |
| Real estate investments | 1 | — | — | 2 | 3 |
| Private equity | — | — | — | 1 | 1 |
| Total | $ 9 | $ 12 | $ — | $ 3 | $ 24 |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

| As of December 31, 2016: | Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Net Asset Value as a Practical Expedient (NAV) | Total |
|---|---|---|---|---|---|
| | *(in millions)* | | | | |
| Assets: | | | | | |
| Domestic equity (*) | $ 4 | $ 2 | $ — | $ — | $ 6 |
| International equity (*) | 2 | 2 | — | — | 4 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 5 | — | — | 5 |
| Corporate bonds | — | 2 | — | — | 2 |
| Pooled funds | — | 1 | — | — | 1 |
| Cash equivalents and other | 2 | — | — | — | 2 |
| Real estate investments | 1 | — | — | 2 | 3 |
| Private equity | — | — | — | 1 | 1 |
| Total | $ 9 | $ 12 | $ — | $ 3 | $ 24 |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

### Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company matches a portion of the first 6% of employee base salary contributions. The maximum Company match is 5.1% of an employee's base salary. Total matching contributions made to the plan for 2017 , 2016 , and 2015 were $5 million each year.

## 3. CONTINGENCIES AND REGULATORY MATTERS

### General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as standards for air, water, land, and protection of other natural resources, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by $CO_2$ and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

### Environmental Matters

#### *Environmental Remediation*

The Company must comply with environmental laws and regulations governing the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up affected sites. The Company has authority from the Mississippi PSC to recover approved environmental compliance costs through established regulatory mechanisms. The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable and reasonably estimable.

## FERC Matters

### *Municipal and Rural Associations Tariff*

The Company provides wholesale electric service to Cooperative Energy, East Mississippi Electric Power Association, and the City of Collins, all located in southeastern Mississippi, under a long-term cost-based, FERC regulated MRA tariff.

In March 2016, the Company reached a settlement agreement with its wholesale customers, which was subsequently approved by the FERC, for an increase in wholesale base revenues under the MRA cost-based electric tariff, primarily as a result of placing scrubbers for Plant Daniel Units 1 and 2 in service in 2015. The settlement agreement became effective for services rendered beginning May 1, 2016, resulting in an estimated annual revenue increase of $7 million under the MRA cost-based electric tariff. Additionally, under the settlement agreement, the tariff customers agreed to similar regulatory treatment for MRA tariff ratemaking as the treatment approved for retail ratemaking through an order issued by the Mississippi PSC in December 2015 (In-Service Asset Rate Order). This regulatory treatment primarily includes (i) recovery of the operational Kemper County energy facility assets providing service to customers and other related costs, (ii) amortization of the Kemper County energy facility-related regulatory assets included in rates under the settlement agreement over the 36 months ending April 30, 2019, (iii) Kemper County energy facility-related expenses included in rates under the settlement agreement no longer being deferred and charged to expense, and (iv) removing all of the Kemper County energy facility CWIP from rate base with a corresponding increase in accrual of AFUDC. The additional resulting AFUDC totaled approximately $22 million through the suspension of Kemper IGCC start-up activities and has been recorded as a charge to income.

On September 18, 2017, the Company and Cooperative Energy executed a Shared Service Agreement (SSA), as part of the MRA tariff, under which the Company and Cooperative Energy will share in providing electricity to all Cooperative Energy delivery points, in lieu of the current arrangement under which each delivery point is specifically assigned to either entity. The SSA accepted by the FERC on October 31, 2017 became effective on January 1, 2018 and may be cancelled by Cooperative Energy with 10 years notice after December 31, 2020. The SSA provides Cooperative Energy the option to decrease its use of the Company's generation services under the MRA tariff, subject to annual and cumulative caps and a one -year notice requirement. In the event Cooperative Energy elects to reduce these services, the related reduction in the Company's revenues is not expected to be significant through 2020.

### *Fuel Cost Recovery*

The Company has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. At December 31, 2017 , over-recovered wholesale MRA fuel costs were immaterial and at December 31, 2016 were approximately $13 million , and is included in over-recovered regulatory clause liabilities, current in the balance sheet. Effective January 1, 2018, the wholesale MRA fuel rate increased $11 million annually.

The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor should have no significant effect on the Company's revenues or net income, but will affect cash flow.

### *Market-Based Rate Authority*

The Company has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies (including the Company) and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In 2015, the FERC issued an order finding that the traditional electric operating companies' (including the Company's) and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional electric operating companies (including the Company) and Southern Power filed a request for rehearing and filed their response with the FERC in 2015.

In December 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. On May 17, 2017, the FERC accepted the traditional electric operating companies' (including the Company's) and Southern Power's compliance filing accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

On October 25, 2017, the FERC issued an order in response to the traditional electric operating companies' (including the Company's) and Southern Power's June 29, 2017 triennial updated market power analysis. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show cause within 60 days why market-based rate authority should not be revoked in certain areas adjacent to the area presently under mitigation in accordance with the February 2, 2017 order or to provide a mitigation plan to further address market power concerns. On November 10, 2017, the traditional electric operating companies (including the Company) and Southern Power responded to the FERC and proposed to resolve matters by applying the alternative mitigation authorized by the February 2, 2017 order to the adjacent areas made the subject of the October 25, 2017 order.

The ultimate outcome of these matters cannot be determined at this time.

***Cooperative Energy Power Supply Agreement***

In 2008, the Company entered into a 10 -year Power Supply Agreement (PSA) with Cooperative Energy for approximately 152 MWs, which became effective in 2011. Following certain plant retirements, the PSA capacity was reduced to 86 MWs. On February 5, 2018, the Company and Cooperative Energy executed an amendment to extend the PSA through March 31, 2021, effective April 1, 2018, with increased total capacity of 286 MWs.

Cooperative Energy also has a 10 -year Network Integration Transmission Service Agreement (NITSA) with SCS for transmission service to certain delivery points on the Company's transmission system that became effective in 2011. As a result of the PSA amendments, Cooperative Energy and SCS amended the terms of the NITSA on January 12, 2018 to provide for the purchase of incremental transmission capacity for service beginning April 1, 2018 through March 31, 2021. This NITSA amendment remains subject to acceptance by the FERC. The ultimate outcome of these matters cannot be determined at this time.

**Retail Regulatory Matters**

***General***

In 2012, the Mississippi PSC issued an order for the purpose of investigating and reviewing, for informational purposes only, the ROE formulas used by the Company and all other regulated electric utilities in Mississippi. In 2013, the MPUS filed with the Mississippi PSC its report on the ROE formulas used by the Company and all other regulated electric utilities in Mississippi.

In 2014, the Mississippi PSC issued an order for the purpose of investigating and reviewing the adoption of a uniform formula rate plan for the Company and other regulated electric utilities in Mississippi.

On January 26, 2018, the Mississippi PSC issued an order directing utilities to file within 30 days information regarding the impact on rates resulting from Tax Reform Legislation. The Company's Kemper County energy facility rates, approved on February 6, 2018, include the effects of Tax Reform Legislation. The Company's 2018 ECO, revised 2018 PEP, and 2018 SRR rate filings, all submitted in February 2018, include the effects of Tax Reform Legislation and are subject to approval by the Mississippi PSC.

The ultimate outcome of these matters cannot be determined at this time.

***Performance Evaluation Plan***

The Company's retail base rates are set under the PEP, a rate plan approved by the Mississippi PSC. Two filings are made for each calendar year: the PEP projected filing, which is typically filed prior to the beginning of the year based on a projected revenue requirement, and the PEP lookback filing, which is filed after the end of the year and allows for review of the actual revenue requirement compared to the projected filing.

In 2011, the Company submitted its annual PEP lookback filing for 2010, which recommended no surcharge or refund. Later in 2011, the MPUS disputed certain items in the 2010 PEP lookback filing. In 2012, the Mississippi PSC issued an order canceling the Company's PEP lookback filing for 2011. I n 2013, the MPUS contested the Company's PEP lookback filing for 2012, which indicated a refund due to customers of $5 million . Unresolved matters related to the 2010 PEP lookback filing, which remain under review, also impact the 2012 PEP lookback filing.

In 2013, the Mississippi PSC approved the projected PEP filing for 2013, which resulted in a rate increase of 1.9% , or $15 million , annually, effective March 19, 2013. The Company may be entitled to $3 million in additional revenues related to 2013 as a result of the late implementation of the 2013 PEP rate increase.

In 2014, 2015, 2016, and 2017, the Company submitted its annual PEP lookback filings for the prior years, which for 2013 and 2014 each indicated no surcharge or refund and for each of 2015 and 2016 indicated a $5 million surcharge. Additionally, in July 2016, in November 2016, and on November 15, 2017, the Company submitted its annual projected PEP filings for 2016, 2017, and 2018, respectively, which for 2016 and 2017 indicated no change in rates and for 2018 indicated a rate increase of 4% , or $38 million in annual revenues. The Mississippi PSC suspended each of these filings to allow more time for review.

On February 7, 2018, the Company revised its annual projected PEP filing for 2018 to reflect the impacts of Tax Reform Legislation. The revised filing requests an increase of $26 million in annual revenues, based on a performance adjusted ROE of 9.33% and an increased equity ratio of 55% . See Note 5 for additional information.

The ultimate outcome of these matters cannot be determined at this time.

***Energy Efficiency***

In 2013, the Mississippi PSC approved an energy efficiency and conservation rule requiring electric and gas utilities in Mississippi serving more than 25,000 customers to implement energy efficiency programs and standards. Quick Start Plans, which include a portfolio of energy efficiency programs that are intended to provide benefits to a majority of customers, were extended by an order issued by the Mississippi PSC in July 2016, until the time the Mississippi PSC approves a comprehensive portfolio plan program. The ultimate outcome of this matter cannot be determined at this time.

On July 6, 2017, the Mississippi PSC issued an order approving the Company's Energy Efficiency Cost Rider 2017 compliance filing, which increased annual retail revenues by approximately $2 million effective with the first billing cycle for August 2017.

On November 30, 2017, the Company submitted its Energy Efficiency Cost Rider 2018 compliance filing which included a small decrease in annual retail revenues. The ultimate outcome of this matter cannot be determined at this time.

***Environmental Compliance Overview Plan***

In 2012, the Mississippi PSC approved the Company's request for a CPCN to construct scrubbers on Plant Daniel Units 1 and 2, which were placed in service in 2015. These units are jointly owned by the Company and Gulf Power, with 50% ownership each. In 2014, the Company entered into a settlement agreement with the Sierra Club under which, among other things, the Company agreed to retire, repower with natural gas, or convert to an alternative non-fossil fuel source Plant Sweatt Units 1 and 2 ( 80 MWs) no later than December 2018 (and the units were retired in July 2016). The Company also agreed that it would cease burning coal and other solid fuel at Plant Watson Units 4 and 5 ( 750 MWs) and begin operating those units solely on natural gas no later than April 2015 (which occurred in April 2015) and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 ( 200 MWs) no later than April 2016 (which occurred in February and March 2016, respectively) and begin operating those units solely on natural gas (which occurred in June and July 2016, respectively).

In accordance with a 2011 accounting order from the Mississippi PSC, the Company has the authority to defer in a regulatory asset for future recovery all plant retirement- or partial retirement-related costs resulting from environmental regulations. The Mississippi PSC approved $41 million and $17 million of costs that were reclassified to regulatory assets associated with Plant Watson and Plant Greene County, respectively, for amortization over five -year periods that began in July 2016 and July 2017, respectively. As a result, these decisions are not expected to have a material impact on the Company's financial statements.

In August 2016, the Mississippi PSC approved the Company's revised ECO plan filing for 2016, which requested the maximum 2% annual increase in revenues, or approximately $18 million , primarily related to the Plant Daniel Units 1 and 2 scrubbers placed in service in 2015. The revised rates became effective with the first billing cycle for September 2016. Approximately $22 million of related revenue requirements in excess of the 2% maximum was deferred for inclusion in the 2017 filing, along with related carrying costs.

On May 4, 2017, the Mississippi PSC approved the Company's ECO plan filing for 2017, which requested the maximum 2% annual increase in revenues, or approximately $ 18 million , primarily related to the carryforward from the prior year. The rates became effective with the first billing cycle for June 2017. Approximately $26 million of related revenue requirements in excess of the 2% maximum was deferred for inclusion in the 2018 filing, along with related carrying costs.

On February 14, 2018, the Company submitted its ECO plan filing for 2018, including the effects of Tax Reform Legislation, which requested the maximum 2% annual increase in revenues, or approximately $17 million , primarily related to the carryforward from the prior year. Approximately $13 million of related revenue requirements in excess of the 2% maximum, along with related carrying costs, remains deferred for inclusion in the 2019 filing. The ultimate outcome of this matter cannot be determined at this time.

### *Fuel Cost Recovery*

The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. The Company is required to file for an adjustment to the retail fuel cost recovery factor annually. On January 12, 2017, the Mississippi PSC approved the 2017 retail fuel cost recovery factor, effective February 2017 through January 2018, which resulted in an annual revenue increase of approximately $55 million . On November 15, 2017, the Company filed its annual rate adjustment under the retail fuel cost recovery clause, requesting an additional increase of $39 million annually, which the Mississippi PSC approved on January 16, 2018 effective February 2018 through January 2019. At December 31, 2017 , the amount of under-recovered retail fuel costs included in the balance sheet in customer accounts receivable was approximately $6 million compared to $37 million over recovered at December 31, 2016.

The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor should have no significant effect on the Company's revenues or net income, but will affect cash flow.

### *Ad Valorem Tax Adjustment*

The Company establishes, annually, an ad valorem tax adjustment factor that is approved by the Mississippi PSC to collect the ad valorem taxes paid by the Company. On July 6, 2017, the Mississippi PSC approved the Company's annual ad valorem tax adjustment factor filing for 2017, which included an annual rate increase of 0.85% , or $8 million in annual retail revenues, primarily due to increased assessments.

### *System Restoration Rider*

In February 2016, the Company submitted its 2016 SRR rate filing which proposed no changes to either the SRR rate or the annual property damage reserve accrual of $3 million annually. On February 3, 2017, the Company submitted its 2017 SRR rate filing, which proposed an increase in the property damage reserve accrual of $1 million . These filings were suspended by the Mississippi PSC for review.

On January 21, 2017, a tornado caused extensive damage to the Company's transmission and distribution infrastructure. Storm damage repairs were approximately $9 million . A portion of these costs was charged to the retail property damage reserve and was addressed in the 2018 SRR rate filing.

On February 1, 2018, the Company submitted its 2018 SRR rate filing, including the effects of Tax Reform Legislation, which proposed that the SRR rate remain at zero and the annual accrual for the property damage reserve be reduced to $2 million in 2018.

The ultimate outcome of these matters cannot be determined at this time. See Note 1 under "Provision for Property Damage" for additional information.

### *Storm Damage Cost Recovery*

In connection with the damage associated with Hurricane Katrina, the Mississippi PSC authorized the issuance of system restoration bonds in 2006. In accordance with a Mississippi PSC order on January 24, 2017, the Company eliminated the applicable Storm Restoration Charge because the bond sinking fund managed by the Mississippi State Bond Commission is substantially funded.

## Kemper County Energy Facility

### *Overview*

The Kemper County energy facility was designed to utilize IGCC technology with an expected output capacity of 582 MWs and to be fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by the Company and situated adjacent to the Kemper County energy facility. The mine, operated by North American Coal Corporation, started commercial operation in 2013. In connection with the Kemper County energy facility construction, the Company constructed approximately 61 miles of $CO_2$ pipeline infrastructure for the transport of captured $CO_2$ for use in enhanced oil recovery.

### *Schedule and Cost Estimate*

In 2012, the Mississippi PSC issued the 2012 MPSC CPCN Order, confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper County energy facility . The certificated cost estimate of the Kemper County energy facility included in the 2012 MPSC CPCN Order was $2.4 billion , net of approximately $0.57 billion for the cost of the lignite mine and equipment, the cost of the $CO_2$ pipeline facilities, AFUDC, and certain general exceptions (Cost Cap Exceptions). The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion , with recovery of prudently-incurred costs subject to approval by the Mississippi PSC. The Kemper County energy facility was originally projected to be placed in service in May 2014. The Company placed the combined cycle and the associated common facilities portion of the Kemper County energy facility in service in August 2014.

The initial production of syngas began on July 14, 2016 for gasifier "B" and on September 13, 2016 for gasifier "A." The Company achieved integrated operation of both gasifiers on January 29, 2017, including the production of electricity from syngas in both combustion turbines. During testing, the plant produced and captured $CO_2$ , and produced sulfuric acid and ammonia, each of acceptable quality under the related off-take agreements. However, the Company experienced numerous challenges during the extended start-up process to achieve integrated operation of the gasifiers on a sustained basis. In May 2017, after achieving these milestones, the Company determined that a critical system component, the syngas coolers, would need replacement sooner than originally planned, which would require significant lead time and significant cost. In addition, the long-term natural gas price forecast had decreased significantly and the estimated cost of operating and maintaining the facility during the first five full years of operations had increased significantly since certification.

On June 21, 2017, the Mississippi PSC stated its intent to issue an order (which occurred on July 6, 2017) directing the Company to pursue a settlement under which the Kemper County energy facility would be operated as a natural gas plant, rather than an IGCC plant, and address all issues associated with the Kemper County energy facility (Kemper Settlement Order). The Kemper Settlement Order established a new docket for the purposes of pursuing a global settlement of the related costs (Kemper Settlement Docket). On June 28, 2017, the Company notified the Mississippi PSC that it would begin a process to suspend operations and start-up activities on the gasifier portion of the Kemper County energy facility, given the uncertainty as to its future. On February 6, 2018, the Mississippi PSC voted to approve a settlement agreement related to cost recovery for the Kemper County energy facility among the Company, the MPUS, and certain intervenors (Kemper Settlement Agreement).

At the time of project suspension in June 2017, the total cost estimate for the Kemper County energy facility was approximately $7.38 billion , including approximately $5.95 billion of costs subject to the construction cost cap, and was net of the $137 million in Additional DOE Grants. In the aggregate, the Company had recorded charges to income of $3.07 billion ( $1.89 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through May 31, 2017.

Given the Mississippi PSC's stated intent regarding no further rate increase for the Kemper County energy facility and the subsequent suspension, cost recovery of the gasifier portions became no longer probable; therefore, the Company recorded an additional charge to income in June 2017 of $2.8 billion ( $2.0 billion after tax), which included estimated costs associated with the gasifier portions of the plant and lignite mine. During the third and fourth quarters of 2017, the Company recorded charges to income of $242 million ( $206 million after tax), including $164 million for ongoing project costs, estimated mine and gasifier-related costs, and certain termination costs during the suspension period prior to conclusion of the Kemper Settlement Docket , as well as the charge associated with the Kemper Settlement Agreement discussed below. Additional pre-tax cancellation costs, including mine and plant closure and contract termination costs, currently estimated at approximately $50 million to $100 million (excluding salvage), are expected to be incurred in 2018. The Company has begun efforts to dispose of or abandon the mine and gasifier-related assets.

***Rate Recovery***

*Kemper Settlement Agreement*

On February 6, 2018, the Mississippi PSC voted to approve the Kemper Settlement Agreement. The Kemper Settlement Agreement provides for an annual revenue requirement of approximately $99.3 million for costs related to the Kemper County energy facility, which includes the impact of Tax Reform Legislation. The revenue requirement is based on (i) a fixed ROE for 2018 of 8.6% excluding any performance adjustment, (ii) a ROE for 2019 calculated in accordance with PEP, excluding the performance adjustment, (iii) for future years, a performance-based ROE calculated pursuant to PEP, and (iv) amortization periods for the related regulatory assets and liabilities of eight years and six years , respectively. The revenue requirement also reflects a disallowance related to a portion of the Company's investment in the Kemper County energy facility requested for inclusion in rate base, which was recorded in the fourth quarter 2017 as an additional charge to income of approximately $78 million ( $85 million net of accumulated depreciation of $7 million ) pre-tax ( $48 million after tax).

Under the Kemper Settlement Agreement, retail customer rates will reflect a reduction of approximately $26.8 million annually and include no recovery for costs associated with the gasifier portion of the Kemper County energy facility in 2018 or at any future date. On February 12, 2018, the Company made the required compliance filing with the Mississippi PSC. The Kemper Settlement Agreement also requires (i) the CPCN for the Kemper County energy facility to be modified to limit it to natural gas combined cycle operation and (ii) the Company to file a reserve margin plan with the Mississippi PSC by August 2018.

As of December 31, 2017, the balances associated with the Kemper County energy facility regulatory assets and liabilities were $114 million and $26 million , respectively.

As a result of the Mississippi PSC order on February 6, 2018, rate recovery for the Kemper County energy facility is resolved, subject to any future legal challenges.

*2015 Rate Case*

On December 3, 2015, the Mississippi PSC issued the In-Service Asset Rate Order r egarding the Kemper County energy facility assets that were commercially operational and currently providing service to customers (the transmission facilities, combined cycle, natural gas pipeline, and water pipeline) and other related costs. The In-Service Asset Rate Order provided for retail rate recovery of an annual revenue requirement of approximately $126 million , based on the Company's actual average capital structure, with a maximum common equity percentage of 49.733% , a 9.225% return on common equity, and actual embedded interest costs. The In-Service Asset Rate Order also included a prudence finding of all costs in the stipulated revenue requirement calculation for the in-service assets.

In connection with the implementation of the In-Service Asset Rate Order and wholesale rates, the Company began expensing certain ongoing project costs and certain retail debt carrying costs that previously were deferred and began amortizing certain regulatory assets associated with assets placed in service and consulting and legal fees over periods ranging from two years to 10 years. On July 6, 2017, the Mississippi PSC issued an order requiring the Company to establish a regulatory liability account to maintain current rates related to the Kemper County energy facility following the July 2017 completion of the amortization period for certain of these regulatory assets. See "FERC Matters" herein for additional information related to the 2016 settlement agreement with wholesale customers.

***Lignite Mine and $CO_2$ Pipeline Facilities***

The Company owns the lignite mine and equipment and mineral reserves located around the Kemper County energy facility site. The mine started commercial operation in June 2013.

In 2010, the Company executed a 40 -year management fee contract with Liberty Fuels Company, LLC (Liberty Fuels), a wholly-owned subsidiary of The North American Coal Corporation, which developed, constructed, and is responsible for the mining operations through the end of the mine reclamation. As the mining permit holder, Liberty Fuels has a legal obligation to perform mine reclamation and the Company has a contractual obligation to fund all reclamation activities. The Company expects mine reclamation to begin in 2018. In addition to the obligation to fund the reclamation activities, the Company provided working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses. See Note 1 under "Asset Retirement Obligations and Other Costs of Removal" and "Variable Interest Entities" for additional information.

In addition, the Company constructed the $CO_2$ pipeline for the planned transport of captured $CO_2$ for use in enhanced oil recovery and entered into an agreement with Denbury Onshore (Denbury) to purchase the captured $CO_2$ . Denbury has the right to terminate the contract at any time because the Company did not place the Kemper IGCC in service by July 1, 2017.

The ultimate outcome of these matters cannot be determined at this time.

***Litigation***

On April 26, 2016, a complaint against the Company was filed in Harrison County Circuit Court (Circuit Court) by Biloxi Freezing & Processing Inc., Gulfside Casino Partnership, and John Carlton Dean, which was amended and refiled on July 11, 2016 to include, among other things, Southern Company as a defendant. The individual plaintiff alleges that the Company and Southern Company violated the Mississippi Unfair Trade Practices Act. All plaintiffs have alleged that the Company and Southern Company concealed, falsely represented, and failed to fully disclose important facts concerning the cost and schedule of the Kemper County energy facility and that these alleged breaches have unjustly enriched the Company and Southern Company. The plaintiffs seek unspecified actual damages and punitive damages; ask the Circuit Court to appoint a receiver to oversee, operate, manage, and otherwise control all affairs relating to the Kemper County energy facility; ask the Circuit Court to revoke any licenses or certificates authorizing the Company or Southern Company to engage in any business related to the Kemper County energy facility in Mississippi; and seek attorney's fees, costs, and interest. The plaintiffs also seek an injunction to prevent any Kemper County energy facility costs from being charged to customers through electric rates. On June 23, 2017, the Circuit Court ruled in favor of motions by Southern Company and the Company and dismissed the case. On July 7, 2017, the plaintiffs filed notice of an appeal. The Company believes this legal challenge has no merit; however, an adverse outcome in this proceeding could have a material impact on the Company's results of operations, financial condition, and liquidity. The Company intends to vigorously defend itself in this matter and the ultimate outcome of this matter cannot be determined at this time.

On June 9, 2016, Treetop, Greenleaf $CO_2$ Solutions, LLC (Greenleaf), Tenrgys, LLC, Tellus Energy, LLC, WCOA, LLC, and Tellus Operating Group filed a complaint against the Company, Southern Company, and SCS in the state court in Gwinnett County, Georgia. The complaint related to the cancelled $CO_2$ contract with Treetop and alleged fraudulent misrepresentation, fraudulent concealment, civil conspiracy, and breach of contract on the part of the Company, Southern Company, and SCS and sought compensatory damages of $100 million , as well as unspecified punitive damages. Southern Company, the Company, and SCS moved to compel arbitration pursuant to the terms of the $CO_2$ contract, which the court granted on May 4, 2017. On June 28, 2017, Treetop, Greenleaf, Tenrgys, LLC, Tellus Energy, LLC, WCOA, LLC, and Tellus Operating Group filed a claim for arbitration requesting $500 million in damages. On December 28, 2017, the Company reached a settlement agreement with Treetop, Greenleaf, Tenrgys, LLC, Tellus Energy, LLC, WCOA, LLC, and Tellus Operating Group and the arbitration was dismissed.

## 4. JOINT OWNERSHIP AGREEMENTS

The Company and Alabama Power own, as tenants in common, Units 1 and 2 (total capacity of 500 MWs) at Greene County Steam Plant, which is located in Alabama and operated by Alabama Power. Additionally, the Company and Gulf Power, own as tenants in common, Units 1 and 2 (total capacity of 1,000 MWs) at Plant Daniel, which is located in Mississippi and operated by the Company. At December 31, 2017 , the Company's percentage ownership and investment in these jointly-owned facilities in commercial operation were as follows:

| Generating Plant | Company Ownership | Plant in Service | Accumulated Depreciation | CWIP |
|---|---|---|---|---|
| | | | *(in millions)* | |
| Greene County | | | | |
| Units 1 and 2 | 40% | $ 164 | $ 55 | $ 1 |
| Daniel | | | | |
| Units 1 and 2 | 50% | $ 713 | $ 189 | $ 4 |

The Company's proportionate share of plant operating expenses is included in the statements of operations and the Company is responsible for providing its own financing.

## 5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and various combined and separate state income tax returns. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

### Federal Tax Reform Legislation

Following the enactment of Tax Reform Legislation, the SEC staff issued Staff Accounting Bulletin 118 – "Income Tax Accounting Implications of the Tax Cuts and Jobs Act" (SAB 118), which provides for a measurement period of up to one year from the enactment date to complete accounting under GAAP for the tax effects of the legislation. Due to the complex and comprehensive nature of the enacted tax law changes, and their application under GAAP, the Company considers all amounts recorded in the financial statements as a result of Tax Reform Legislation to be "provisional" as discussed in SAB 118 and subject to revision. The Company is awaiting additional guidance from industry and income tax authorities in order to finalize its accounting. The ultimate impact of Tax Reform Legislation on deferred income tax assets and liabilities and the related regulatory assets and liabilities cannot be determined at this time. See Note 3 under "Regulatory Matters" for additional information.

**Current and Deferred Income Taxes**

Details of income tax provisions are as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| Federal — | | | |
| Current | **$ 194** | $ (31) | $ (768) |
| Deferred | **(753)** | (60) | 704 |
| | **(559)** | (91) | (64) |
| State — | | | |
| Current | **—** | (6) | (81) |
| Deferred | **27** | (7) | 73 |
| | **27** | (13) | (8) |
| Total | **$ (532)** | $ (104) | $ (72) |

**NOTES (continued)**
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The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| Deferred tax liabilities — | | |
| Accelerated depreciation | **$ 373** | $ 386 |
| Property basis difference | **242** | 852 |
| Regulatory assets associated with AROs | **34** | 72 |
| Pensions and other benefits | **28** | 49 |
| Regulatory assets associated with employee benefit obligations | **45** | 70 |
| Regulatory assets associated with the Kemper County energy facility | **31** | 82 |
| Regulatory assets associated with Plant Daniel | **9** | 13 |
| Rate differential | **—** | 141 |
| Federal effect of state deferred taxes | **9** | — |
| Ad valorem over/under recovery | **11** | 14 |
| Regulatory assets for Mercury and Air Toxics Standards compliance | **11** | 8 |
| Other | **11** | 91 |
| Total | **804** | 1,778 |
| Deferred tax assets — | | |
| Fuel clause over recovered | **—** | 26 |
| Estimated loss on Kemper IGCC | **722** | 484 |
| Pension and other benefits | **62** | 96 |
| Federal NOL | **40** | 109 |
| Property insurance | **15** | 27 |
| Premium on long-term debt | **7** | 14 |
| AROs | **34** | 72 |
| Property basis difference | **70** | — |
| Affirmative adjustments | **31** | — |
| Regulatory liability associated with Tax Reform Legislation (not subject to normalization) | **27** | — |
| Deferred state tax assets | **133** | 113 |
| Deferred federal tax assets | **—** | 31 |
| Federal effect of state deferred taxes | **—** | 19 |
| Other | **32** | 31 |
| Total | **1,173** | 1,022 |
| Valuation allowance (net of $35 million in federal benefit) | **122** | — |
| Accumulated deferred income tax (assets)/liabilities | **(247)** | 756 |

The implementation of Tax Reform Legislation significantly reduced accumulated deferred income taxes, partially offset by bonus depreciation provisions in the Protecting Americans from Tax Hikes Act. Tax Reform Legislation also significantly reduced tax-related regulatory assets and increased tax-related regulatory liabilities.

At December 31, 2017 , the tax-related regulatory assets were $36 million . These assets are primarily attributable to tax benefits flowed through to customers in prior years, deferred taxes previously recognized at rates lower than the current enacted tax law, and taxes applicable to capitalized interest.

At December 31, 2017 , the tax-related regulatory liabilities were $376 million . These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and unamortized ITCs.

In accordance with regulatory requirements, deferred federal ITCs are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of operations. Credits for non-Kemper County energy facility related deferred ITCs amortized in this manner amounted to $1 million in each of 2017, 2016, and 2015.

At December 31, 2017 , the Company had state of Mississippi NOL carryforwards totaling approximately $2.8 billion , resulting in deferred tax assets of approximately $111 million . The NOLs will expire between 2031 and 2037.

**Effective Tax Rate**

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| Federal statutory rate | **(35.0)%** | (35.0)% | (35.0)% |
| State income tax, net of federal deduction | **0.6** | (5.7) | (6.3) |
| Non-deductible book depreciation | **0.1** | 0.7 | 1.3 |
| AFUDC-equity | **—** | (28.5) | (49.6) |
| Non-deductible equity portion on Kemper IGCC write-off | **5.3** | — | — |
| Tax Reform Legislation | **11.9** | — | — |
| Other | **—** | — | (2.9) |
| Effective income tax rate (benefit rate) | **(17.1)%** | (68.5)% | (92.5)% |

The decrease in the Company's 2017 effective tax rate (benefit rate), as compared to 2016, is primarily due to an increase in estimated losses associated with the Kemper IGCC, a decrease in non-taxable AFUDC equity, and a decrease due to the remeasurement of deferred income taxes resulting from Tax Reform Legislation. The decrease in the Company's 2016 effective tax rate (benefit rate), as compared to 2015, is primarily due to an increase in estimated losses associated with the Kemper IGCC and an increase in non-taxable AFUDC equity.

Tax Reform Legislation reduced the corporate income tax rate from 35% to 21% . As a result of implementation, the Company restated future tax benefits/deductions recorded as deferred tax assets/liabilities to reflect the new rate. The implementation resulted in a $372 million increase in tax expense and a $375 million increase in regulatory liabilities.

In March 2016, the FASB issued ASU 2016-09, which changed the accounting for income taxes for share-based payment award transactions. Entities are required to recognize all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation as income tax expense or benefit in the income statement. The adoption of ASU 2016-09 did not have a material impact on the Company's overall effective tax rate. See Note 1 under "Recently Issued Accounting Standards" for additional information.

**Unrecognized Tax Benefits**

Changes during the year in unrecognized tax benefits were as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| Unrecognized tax benefits at beginning of year | **$ 465** | $ 421 | $ 165 |
| Tax positions increase from current periods | **—** | 26 | 32 |
| Tax positions increase from prior periods | **2** | 18 | 224 |
| Tax positions decrease from prior periods | **(177)** | — | — |
| Reductions due to settlements | **(290)** | — | — |
| Balance at end of year | **$ —** | $ 465 | $ 421 |

The tax positions increases from current periods and prior periods for 2017, 2016 and 2015 relate to state tax benefits, deductions for R&E expenditures, and charitable contribution carryforwards that were impacted as a result of the settlement of R&E expenditures associated with the Kemper County energy facility, as well as federal income tax benefits from deferred ITCs. The tax positions decrease from prior periods and reductions due to settlements for 2017 relate primarily to the settlement of R&E expenditures associated with the Kemper County energy facility. See "Section 174 Research and Experimental Deduction" herein for additional information. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

The impact on the Company's effective tax rate, if recognized, is as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| Tax positions impacting the effective tax rate | **$ —** | $ 1 | $ (2) |
| Tax positions not impacting the effective tax rate | **—** | 464 | 423 |
| Balance of unrecognized tax benefits | **$ —** | $ 465 | $ 421 |

The tax positions not impacting the effective tax rate primarily relate to state tax benefits and charitable contribution carryforwards that were impacted as a result of the settlement of R&E expenditures associated with the Kemper County energy facility. See "Section 174 Research and Experimental Deduction" herein for additional information.

Accrued interest for unrecognized tax benefits was as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| Interest accrued at beginning of year | **$ 28** | $ 13 | $ 3 |
| Interest accrued during the year | **(28)** | 15 | 10 |
| Balance at end of year | **$ —** | $ 28 | $ 13 |

The Company classifies interest on tax uncertainties as interest expense. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months . The settlement of federal and state audits could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2016. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2011.

***Section 174 Research and Experimental Deduction***

Southern Company, on behalf of the Company, has reflected deductions for R&E expenditures related to the Kemper County energy facility in its federal income tax calculations since 2013 and filed amended federal income tax returns for 2008 through 2013 to also include such deductions. In December 2016, Southern Company and the IRS reached a proposed settlement, which was approved on September 8, 2017 by the U.S. Congress Joint Committee on Taxation (JCT), resolving a methodology for these deductions. As a result of the JCT approval, Southern Company recognized $176 million of previously unrecognized tax benefits and reversed $36 million of associated accrued interest.

## 6. FINANCING

### Going Concern

The Company's financial statement presentation contemplates continuation of the Company as a going concern as a result of Southern Company's anticipated ongoing financial support of the Company. Specifically, the Company has been informed by Southern Company that in the event sufficient funds are not available from external sources, Southern Company intends to provide the Company with loans and/or equity to fund the remaining indebtedness to mature and other cash needs over the next 12 months. As of December 31, 2017, the Company's current liabilities exceeded current assets by approximately $911 million primarily due to a $900 million unsecured term loan that matures on March 31, 2018. The Company expects to refinance the unsecured term loan with external security issuances and/or borrowings from financial institutions or Southern Company. To fund the Company's capital needs over the next 12 months, the Company intends to utilize operating cash flows, external security issuances, lines of credit, bank term loans, equity contributions from Southern Company and, to the extent necessary, loans from Southern Company.

### Securities Due Within One Year

A summary of scheduled maturities and redemptions of securities due within one year at December 31, 2017 and 2016 was as follows:

| | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| Parent company loans | **$ —** | $ 551 |
| Senior notes | **—** | 35 |
| Bank term loans | **900** | — |
| Revenue bonds (*) | **90** | 40 |
| Capitalized leases | **—** | 3 |
| Unamortized debt issuance expense | **(1)** | — |
| **Outstanding at December 31** | **$ 989** | $ 629 |

(*) Includes $50 million in revenue bonds classified as short term at December 31, 2017 that were remarketed in an index rate mode subsequent to December 31, 2017. Also includes $40 million in pollution control revenue bonds classified as short term since they are variable rate demand obligations supported by short-term credit facilities; however, the final maturity dates range from 2020 to 2028.

Maturities through 2022 applicable to total long-term debt are as follows: $900 million in 2018, $125 million in 2019, and $270 million in 2021. For long-term debt, other than revenue bonds, there are no scheduled maturities for 2020 and 2022.

### Parent Company Loans and Equity Contributions

At December 31, 2016, the Company had $551 million of outstanding promissory notes to Southern Company.

In February 2017, the Company amended $551 million in promissory notes to Southern Company extending the maturity dates of the notes from December 1, 2017 to July 31, 2018. In the second quarter 2017, the Company borrowed an additional $40 million under a promissory note issued to Southern Company.

In June 2017, Southern Company made equity contributions totaling $1.0 billion to the Company. The Company used a portion of the proceeds to (i) prepay $300 million of the outstanding principal amount under its $1.2 billion unsecured term loan, which matures on March 30, 2018; (ii) repay all of the $591 million outstanding principal amount of promissory notes to Southern Company; and (iii) repay a $10 million short-term bank loan.

In September 2017, the Company issued a floating rate promissory note to Southern Company in an aggregate principal amount of up to $150 million bearing interest based on one-month LIBOR. The Company borrowed $109 million under this promissory note primarily to satisfy its federal income tax obligations for the quarter ending September 30, 2017 and subsequently repaid the promissory note upon receipt of its income tax refund from the U.S. federal government related to the settlement concerning deductible R&E expenditures. See Note 5 under "Section 174 Research and Experimental Deduction" for additional information. At December 31, 2017, the Company had no outstanding promissory notes to Southern Company.

### Bank Term Loans

In March 2017, the Company issued a $9 million short-term bank note bearing interest at 5% per annum, which was repaid in April 2017.

In June 2017, the Company used a portion of the proceeds from Southern Company equity contributions to prepay $300 million of the outstanding principal amount under its $1.2 billion unsecured term loan, which matures on March 30, 2018, and to repay $10 million of the outstanding principal amount of bank loans. See "Parent Company Loans and Equity Contributions" herein for more information.

This unsecured term loan has a covenant that limits debt levels to 65% of total capitalization, as defined in the agreement. For purposes of this definition, debt excludes any long-term debt payable to affiliated trusts and other hybrid securities. At December 31, 2017 , the Company was in compliance with its debt limit.

In August 2017, the Company repaid a $12.5 million short-term bank note.

At December 31, 2017 , the Company had a $900 million unsecured term loan outstanding, which was reflected in the statements of capitalization as securities due within one year. At December 31, 2016 , the Company had a $1.2 billion unsecured term loan outstanding, which was reflected in the statements of capitalization as long-term debt.

**Senior Notes**

At December 31, 2017 and 2016 , the Company had $755 million and $790 million of senior notes outstanding, respectively, which included senior notes due within one year . These senior notes are effectively subordinated to the secured debt of the Company. See "Plant Daniel Revenue Bonds" below for additional information regarding the Company's secured indebtedness.

**Plant Daniel Revenue Bonds**

In 2011, in connection with the Company's election under its operating lease of Plant Daniel Units 3 and 4 to purchase the assets, the Company assumed the obligations of the lessor related to $270 million aggregate principal amount of Mississippi Business Finance Corporation Taxable Revenue Bonds, 7.13% Series 1999A due October 20, 2021, issued for the benefit of the lessor. These bonds are secured by Plant Daniel Units 3 and 4 and certain related personal property. The bonds were recorded at fair value as of the date of assumption, or $346 million , reflecting a premium of $76 million . See "Assets Subject to Lien" herein for additional information.

**Pollution Control Revenue Bonds**

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of pollution control revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2017 and 2016 was $83 million .

**Other Revenue Bonds**

Other revenue bond obligations represent loans to the Company from a public authority of funds derived from the sale by such authority of revenue bonds issued to finance a portion of the costs of constructing the Kemper County energy facility and related facilities.

The Company had $50 million of such obligations outstanding related to tax-exempt revenue bonds at December 31, 2017 and 2016 . Such amounts are reflected in the statements of capitalization as long-term debt.

**Capital Leases**

In 2013, the Company entered into an agreement to sell the air separation unit for the Kemper County energy facility and also entered into a 20 -year nitrogen supply agreement. The nitrogen supply agreement was determined to be a sale/leaseback agreement, which resulted in a capital lease obligation of $74 million at December 31, 2016. Following the suspension of the Kemper IGCC, the Company entered into an asset purchase and settlement agreement in December 2017 with the lessor, which terminated the capital lease obligation. There were no contingent rentals in the contract and a portion of the monthly payment specified in the agreement was related to executory costs for the operation and maintenance of the air separation unit and excluded from the minimum lease payments. The minimum lease payments for 2017 were $7 million . See Note 3 under "Kemper County Energy facility" for additional information.

**Assets Subject to Lien**

The revenue bonds assumed in conjunction with the purchase of Plant Daniel Units 3 and 4 are secured by Plant Daniel Units 3 and 4 and certain related personal property. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy the obligations of Southern Company or another of its other subsidiaries. See "Plant Daniel Revenue Bonds" herein for additional information.

On October 4, 2017, the Company executed agreements with its largest retail customer, Chevron Products Company (Chevron), to continue providing retail service to the Chevron refinery in Pascagoula, Mississippi through 2038, subject to the approval of the Mississippi PSC. The agreements grant Chevron a security interest in its co-generation assets, with a net book value of approximately $93 million , located at Chevron's refinery that is exercisable upon the occurrence of (i) certain bankruptcy events or (ii) other events of default coupled with specific reductions in steam output at the facility and a downgrade of the Company's credit rating to below investment grade by two of the three rating agencies.

### Outstanding Classes of Capital Stock

The Company currently has preferred stock (including depositary shares which represent one-fourth of a share of preferred stock) and common stock authorized and outstanding. The preferred stock of the Company contains a feature that allows the holders to elect a majority of the Company's board of directors if preferred dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of the Company, this preferred stock is presented as "Cumulative Redeemable Preferred Stock" in a manner consistent with temporary equity under applicable accounting standards. The Company's preferred stock and depositary preferred stock, without preference between classes, rank senior to the Company's common stock with respect to payment of dividends and voluntary or involuntary dissolution. The preferred stock and depositary preferred stock is subject to redemption at the option of the Company at a redemption price equal to 100% of the liquidation amount of the stock. Information for each outstanding series is in the table below:

| Preferred Stock | Par Value/Stated Capital Per Share | Shares Outstanding | Redemption Price Per Share |
|---|---|---|---|
| 4.40% Preferred Stock | $ 100 | 8,867 | $ 104.32 |
| 4.60% Preferred Stock | $ 100 | 8,643 | $ 107.00 |
| 4.72% Preferred Stock | $ 100 | 16,700 | $ 102.25 |
| 5.25% Preferred Stock (*) | $ 100 | 300,000 | $ 100.00 |

(*) There are 1,200,000 outstanding depositary shares, each representing one-fourth of a share of the 5.25% preferred stock.

### Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

### Bank Credit Arrangements

At December 31, 2017 , committed credit arrangements with banks were as follows:

| Expires | | | Executable Term Loans | | Expires Within One Year | |
|---|---|---|---|---|---|---|
| 2018 | Total | Unused | One Year | Two Years | Term Out | No Term Out |
| *(in millions)* | *(in millions)* | | *(in millions)* | | *(in millions)* | |
| $100 | $100 | $100 | $— | $— | $— | $100 |

In November 2017, the Company amended certain of its one-year credit arrangements in an aggregate amount of $100 million to extend the maturity dates from 2017 to 2018.

Subject to applicable market conditions, the Company expects to renew its bank credit arrangements, as needed, prior to expiration. In connection therewith, the Company may extend the maturity dates and/or increase or decrease the lending commitments thereunder.

Most of these bank credit arrangements require payment of commitment fees based on the unused portions of the commitments or to maintain compensating balances with the banks. Commitment fees average less than 1/4 of 1% for the Company. Compensating balances are not legally restricted from withdrawal.

Most of these bank credit arrangements contain covenants that limit the Company's debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes certain hybrid securities.

A portion of the $100 million unused credit with banks is allocated to provide liquidity support to the Company's pollution control revenue bonds and its commercial paper borrowings. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2017 was $40 million . In addition, at December 31, 2017, the Company had approximately $50 million of fixed rate revenue bonds that were remarketed from a long-term interest rate mode to an index rate mode, subsequent to December 31, 2017 .

At December 31, 2017 and 2016 , there was no commercial paper debt outstanding.

At December 31, 2017 and 2016 , there was $4 million and $23 million , respectively, of short-term debt outstanding.

## 7. COMMITMENTS

### Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil fuel which are not recognized on the balance sheets. In 2017 , 2016 , and 2015 , the Company incurred fuel expense of $395 million , $343 million , and $443 million , respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other traditional electric operating companies and Southern Power. Under these agreements, each of the traditional electric operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional electric operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

In addition, the Company has entered into various long-term commitments for the purchase of energy through PPAs associated with solar facilities. The energy related costs associated with PPAs are recovered through the fuel cost recovery clause.

### Operating Leases

The Company has entered into operating leases with Southern Linc and third parties for the use of cellular tower space. These agreements have initial terms ranging from five to 10 years and renewal options of up to 20 years . The Company has other operating lease agreements with various terms and expiration dates. Total rent expense was $3 million , $3 million , and $5 million for 2017 , 2016 , and 2015 , respectively. The Company includes any step rents, fixed escalations, lease concessions, and reasonably assured renewal periods in its computation of minimum lease payments.

Estimated minimum lease payments under operating leases at December 31, 2017 were as follows:

| | Affiliate Operating Leases (a) | Non-Affiliate Operating Lease (b) | Total |
|---|---|---|---|
| | | *(in millions)* | |
| 2018 | $ 2 | $ 1 | $ 3 |
| 2019 | 2 | 1 | 3 |
| 2020 | 2 | 1 | 3 |
| 2021 | 2 | — | 2 |
| 2022 | 2 | — | 2 |
| 2023 and thereafter | 7 | — | 7 |
| Total | $ 17 | $ 3 | $ 20 |

(a) Includes operating leases with affiliates primarily related to cellular towers.

(b) Primarily includes railcar and fuel handling equipment leases for Plant Daniel.

In addition to the above rental commitments, the Company entered into operating lease agreements for aluminum railcars for the transportation of coal at Plant Daniel, which is jointly owned with Gulf Power. The Company has the option to purchase the railcars at the greater of lease termination value or fair market value or to renew the leases at the end of the lease term. The Company also has separate lease agreements for other railcars that do not contain a purchase option.

The Company's 50% share of the lease costs, charged to fuel stock and recovered through the fuel cost recovery clause, was $1 million in 2017 , $2 million in 2016 , and $2 million in 2015 .

In addition to railcar leases, the Company has other operating leases for fuel handling equipment at Plant Daniel. The Company's 50% share of the leases for fuel handling was charged to fuel handling expense annually from 2015 through 2017 ; however, those amounts were immaterial for the reporting period.

## 8. STOCK COMPENSATION

### Stock-Based Compensation

Stock-based compensation primarily in the form of Southern Company performance share units and restricted stock units may be granted through the Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. In 2015 and 2016, stock-based compensation consisted exclusively of performance share units. Beginning in 2017, stock-based compensation granted to employees includes restricted stock units in addition to performance share units. Prior to 2015, stock-based compensation also included stock options. As of December 31, 2017 , there were 180 current and former employees participating in the stock option, performance share unit, and restricted stock unit programs.

### *Performance Share Units*

Performance share units granted to employees vest at the end of a three -year performance period. All unvested performance share units vest immediately upon a change in control where Southern Company is not the surviving corporation. Shares of Southern Company common stock are delivered to employees at the end of the performance period with the number of shares issued ranging from 0% to 200% of the target number of performance share units granted, based on achievement of the performance goals established by the Compensation Committee of the Southern Company Board of Directors.

Southern Company issues performance share units with performance goals based on three performance goals to employees. These include performance share units with performance goals based on the total shareholder return (TSR) for Southern Company common stock during the three -year performance period as compared to a group of industry peers, performance share units with performance goals based on Southern Company's cumulative earnings per share (EPS) over the performance period, and performance share units with performance goals based on Southern Company's equity-weighted ROE over the performance period.

In 2015 and 2016, the EPS-based and ROE-based awards each represented 25% of the total target grant date fair value of the performance share unit awards granted. The remaining 50% of the total target grant date fair value consisted of TSR-based awards. Beginning in 2017, the total target grant date fair value of the stock compensation awards granted was comprised 20% each of EPS-based awards and ROE-based awards and 30% each of TSR-based awards and restricted stock units.

The fair value of TSR-based performance share unit awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's common stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three -year performance period without remeasurement.

The fair values of the EPS-based awards and the ROE-based awards are based on the closing stock price of Southern Company common stock on the date of the grant. Compensation expense for the EPS-based and ROE-based awards is generally recognized ratably over the three -year performance period initially assuming a 100% payout at the end of the performance period. Employees become immediately vested in the TSR-based performance share units, along with the EPS-based and ROE-based awards, upon retirement. As a result, compensation expense for employees that are retirement eligible at the grant date is recognized immediately while compensation expense for employees that become retirement eligible during the vesting period is recognized over the period from grant date to the date of retirement eligibility. The expected payout related to the EPS-based and ROE-based awards is reevaluated annually with expense recognized to date increased or decreased based on the number of shares currently expected to be issued. Unlike the TSR-based awards, the compensation expense ultimately recognized for the EPS-based awards and the ROE-based awards will be based on the actual number of shares issued at the end of the performance period.

For the years ended December 31, 2017 , 2016 , and 2015 , employees of the Company were granted performance share units of 30,933 , 62,435 , and 53,909 , respectively. The weighted average grant-date fair value of TSR-based performance share units granted during 2017 , 2016 , and 2015 , determined using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period, was \$49.24 , \$45.17 , and \$46.41 , respectively. The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2017, 2016, and 2015 was \$49.22 , \$48.84 , and \$47.77 , respectively.

For the years ended December 31, 2017 , 2016 , and 2015 , total compensation cost for performance share units recognized in income was \$2 million , \$4 million , and \$4 million , respectively, with the related tax benefit also recognized in income of \$1 million , \$1 million , and \$2 million , respectively. The compensation cost related to the grant of Southern Company performance share units to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2017 , total unrecognized compensation cost related to performance share award units was immaterial.

***Restricted Stock Units***

Beginning in 2017, stock-based compensation granted to employees included restricted stock units in addition to performance share units. One-third of the restricted stock units granted to employees vest each year throughout a three -year service period. All unvested restricted stock units vest immediately upon a change in control where Southern Company is not the surviving corporation. Shares of Southern Company common stock are delivered to employees at the end of the vesting period.

The fair value of restricted stock units is based on the closing stock price of Southern Company common stock on the date of the grant. Since one-third of the restricted stock units vest each year throughout a three -year service period, compensation expense for restricted stock unit awards is generally recognized over the corresponding one-, two-, or three-year period. Employees become immediately vested in the restricted stock units upon retirement. As a result, compensation expense for employees that are retirement eligible at the grant date is recognized immediately while compensation expense for employees that become retirement eligible during the vesting period is recognized over the period from grant date to the date of retirement eligibility.

For the year ended December 31, 2017 , employees of the Company were granted 13,260 restricted stock units. The weighted average grant-date fair value of restricted stock units granted during 2017 was $49.22 .

For the year ended December 31, 2017 , total compensation cost for restricted stock units and the related tax benefit also recognized in income was immaterial. As of December 31, 2017 , total unrecognized compensation cost related to restricted stock units was immaterial.

***Stock Options***

In 2015, Southern Company discontinued the granting of stock options. Stock options expire no later than 10 years after the grant date and the latest possible exercise will occur no later than November 2024.

The compensation cost related to the grant of Southern Company stock options to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. Compensation cost and related tax benefits recognized in the Company's financial statements were not material for any year presented. As of December 31, 2017 , all compensation cost related to stock option awards has been recognized.

The total intrinsic value of options exercised during the years ended December 31, 2017 , 2016 , and 2015 was $2 million , $4 million , and $3 million , respectively. No cash proceeds are received by the Company upon the exercise of stock options. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $1 million , $2 million , and $1 million for the years ended December 31, 2017 , 2016 , and 2015 , respectively. Prior to the adoption of ASU 2016-09 in 2016, the excess tax benefits related to the exercise of stock options were recognized in the Company's financial statements with a credit to equity. Upon the adoption of ASU 2016-09, beginning in 2016, all tax benefits related to the exercise of stock options are recognized in income. As of December 31, 2017 , the aggregate intrinsic value for the options outstanding and exercisable was $4 million .

**9. FAIR VALUE MEASUREMENTS**

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 2017 , assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

| | Fair Value Measurements Using | | | |
|---|---|---|---|---|
| **As of December 31, 2017:** | **Quoted Prices in Active Markets for Identical Assets (Level 1)** | **Significant Other Observable Inputs (Level 2)** | **Significant Unobservable Inputs (Level 3)** | **Total** |
| | | *(in millions)* | | |
| Assets: | | | | |
| Energy-related derivatives | $ — | $ 2 | $ — | $ 2 |
| Interest rate derivatives | — | 1 | — | 1 |
| Cash equivalents | 224 | — | — | 224 |
| Total | $ 224 | $ 3 | $ — | $ 227 |
| Liabilities: | | | | |
| Energy-related derivatives | $ — | $ 9 | $ — | $ 9 |

As of December 31, 2016 , assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

| | Fair Value Measurements Using | | | |
|---|---|---|---|---|
| **As of December 31, 2016:** | **Quoted Prices in Active Markets for Identical Assets (Level 1)** | **Significant Other Observable Inputs (Level 2)** | **Significant Unobservable Inputs (Level 3)** | **Total** |
| | | *(in millions)* | | |
| Assets: | | | | |
| Energy-related derivatives | $ — | $ 3 | $ — | $ 3 |
| Interest rate derivatives | — | 3 | — | 3 |
| Cash equivalents | 206 | — | — | 206 |
| Total | $ 206 | $ 6 | $ — | $ 212 |
| Liabilities: | | | | |
| Energy-related derivatives | $ — | $ 10 | $ — | $ 10 |

**Valuation Methodologies**

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. See Note 10 for additional information on how these derivatives are used.

As of December 31, 2017 and 2016 , other financial instruments for which the carrying amount did not equal fair value were as follows:

| | Carrying Amount | Fair Value |
|---|---|---|
| | *(in millions)* | |
| Long-term debt: | | |
| **2017** | **$ 2,086** | **$ 2,076** |
| 2016 | $ 2,979 | $ 2,922 |

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates offered to the Company.

## 10. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a net basis. See Note 9 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

### Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in energy-related commodity prices. The Company manages fuel-hedging programs, implemented per the guidelines of the Mississippi PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

Energy-related derivative contracts are accounted for under one of the following methods:

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the respective fuel cost recovery clauses.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of operations as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2017 , the net volume of energy-related derivative contracts for natural gas positions totaled 53 million mmBtu for the Company, with the longest hedge date of 2021 over which the Company is hedging its exposure to the variability in future cash flows for forecasted transactions.

In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 4 million mmBtu.

### Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to income.

At December 31, 2017 , the following interest rate derivatives were outstanding:

| | Notional Amount | Interest Rate Received | Weighted Average Interest Rate Paid | Hedge Maturity Date | Fair Value Gain (Loss) December 31, 2017 |
|---|---|---|---|---|---|
| | *(in millions)* | | | | *(in millions)* |
| ***Cash Flow Hedges of Existing Debt*** | $ 900 | 1-month LIBOR | 0.79% | March 2018 | $ 1 |

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the next 12-month period ending December 31, 2018 are $0.5 million . The Company has deferred gains and losses that are expected to be amortized into earnings through 2022 .

**Derivative Financial Statement Presentation and Amounts**

The Company enters into energy-related and interest rate derivative contracts that may contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Fair value amounts of derivative assets and liabilities on the balance sheets are presented net to the extent that there are netting arrangements or similar agreements with counterparties.

At December 31, 2017 and 2016 , the fair value of energy-related derivatives and interest rate derivatives was reflected on the balance sheets as follows:

| | **2017** | | 2016 | |
|---|---|---|---|---|
| **Derivative Category and Balance Sheet Location** | **Assets** | **Liabilities** | Assets | Liabilities |
| | | *(in millions)* | | |
| **Derivatives designated as hedging instruments for regulatory purposes** | | | | |
| Energy-related derivatives: | | | | |
| Other current assets/Other current liabilities | **$ 1** | **$ 6** | $ 2 | $ 6 |
| Other deferred charges and assets/Other deferred credits and liabilities | **1** | **3** | 2 | 5 |
| **Total derivatives designated as hedging instruments for regulatory purposes** | **$ 2** | **$ 9** | $ 4 | $ 11 |
| **Derivatives designated as hedging instruments in cash flow and fair value hedges** | | | | |
| Interest rate derivatives: | | | | |
| Other current assets/Other current liabilities | **$ 1** | **$ —** | $ 2 | $ — |
| Other deferred charges and assets/Other deferred credits and liabilities | **—** | **—** | 1 | — |
| **Total derivatives designated as hedging instruments in cash flow and fair value hedges** | **$ 1** | **$ —** | $ 3 | $ — |
| **Gross amounts recognized** | **$ 3** | **$ 9** | $ 7 | $ 11 |
| **Gross amounts offset** | **$ (2)** | **$ (2)** | $ (3) | $ (3) |
| **Net amounts recognized in the Balance Sheets** | **$ 1** | **$ 7** | $ 4 | $ 8 |

Energy-related derivatives not designated as hedging instruments were immaterial for 2017 and 2016 .

At December 31, 2017 and 2016 , the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivatives designated as regulatory hedging instruments and deferred were as follows:

| | Unrealized Losses | | | Unrealized Gains | | |
|---|---|---|---|---|---|---|
| **Derivative Category** | **Balance Sheet Location** | **2017** | 2016 | **Balance Sheet Location** | **2017** | 2016 |
| | | *(in millions)* | | | *(in millions)* | |
| Energy-related derivatives: | Other regulatory assets, current | **$ (5)** | $ (5) | Other current liabilities | **$ —** | $ 1 |
| | Other regulatory assets, deferred | **(2)** | (3) | Other regulatory liabilities, deferred | **—** | — |
| **Total energy-related derivative gains (losses)** | | **$ (7)** | $ (8) | | **$ —** | $ 1 |

For all years presented, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of operations were immaterial.

For the years ended December 31, 2017, 2016, and 2015, the pre-tax effects of derivatives designated as cash flow hedging instruments on the statements of operations were immaterial.

**Contingent Features**

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2017 , the Company had no collateral posted with its derivative counterparties.

At December 31, 2017 , the fair value of derivative liabilities with contingent features was $1 million . However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $12 million , and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

## 11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2017 and 2016 is as follows:

| Quarter Ended | Operating Revenues | Operating Income (Loss) | Net Income (Loss) After Dividends on Preferred Stock |
|---|---|---|---|
| | | *(in millions)* | |
| **March 2017** | **$ 272** | **$ (62)** | **$ (20)** |
| **June 2017** | **303** | **(2,954)** | **(2,054)** |
| **September 2017** | **341** | **51** | **40** |
| **December 2017** | **271** | **(177)** | **(556)** |
| | | | |
| March 2016 | $ 257 | $ (10) | $ 11 |
| June 2016 | 277 | (28) | 2 |
| September 2016 | 352 | 9 | 26 |
| December 2016 | 277 | (166) | (89) |

As a result of the revisions to the cost estimate for the Kemper IGCC and its June 2017 suspension, the Company recorded total pre-tax charges to income related to the Kemper IGCC of $208 million ( $185 million after tax) in the fourth quarter 2017, $34 million ( $21 million after tax) in the third quarter 2017, $3.0 billion ( $2.1 billion after tax) in the second quarter 2017, $108 million ( $67 million after tax) in the first quarter 2017, $206 million ( $127 million after tax) in the fourth quarter 2016, $88 million ( $54 million after tax) in the third quarter 2016, $81 million ( $50 million after tax) in the second quarter 2016, and $53 million ( $33 million after tax) in the first quarter 2016. See Note 3 under "Kemper County Energy Facility" for additional information.

As a result of Tax Reform Legislation, the Company recorded total income tax expense of $372 million in the fourth quarter 2017. See Note 5 for additional information.

The Company's business is influenced by seasonal weather conditions.

**SELECTED FINANCIAL AND OPERATING DATA 2013 - 2017**
**Mississippi Power Company 2017 Annual Report**

| | 2017 | 2016 | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|
| **Operating Revenues (in millions)** | **$ 1,187** | $ 1,163 | $ 1,138 | $ 1,243 | $ 1,145 |
| **Net Income (Loss) After Dividends on Preferred Stock (in millions)** [(a)] | **$ (2,590)** | $ (50) | $ (8) | $ (329) | $ (477) |
| **Cash Dividends on Common Stock (in millions)** | **$ —** | $ — | $ — | $ — | $ 72 |
| **Return on Average Common Equity (percent)** [(a)] | **(120.43)** | (1.87) | (0.34) | (15.43) | (24.28) |
| **Total Assets (in millions)** [(b)(c)] | **$ 4,866** | $ 8,235 | $ 7,840 | $ 6,642 | $ 5,822 |
| **Gross Property Additions (in millions)** | **$ 536** | $ 946 | $ 972 | $ 1,389 | $ 1,773 |
| **Capitalization (in millions):** | | | | | |
| Common stock equity | **$ 1,358** | $ 2,943 | $ 2,359 | $ 2,084 | $ 2,177 |
| Redeemable preferred stock | **33** | 33 | 33 | 33 | 33 |
| Long-term debt [(b)] | **1,097** | 2,424 | 1,886 | 1,621 | 2,157 |
| Total (excluding amounts due within one year) | **$ 2,488** | $ 5,400 | $ 4,278 | $ 3,738 | $ 4,367 |
| **Capitalization Ratios (percent):** | | | | | |
| Common stock equity | **54.6** | 54.5 | 55.1 | 55.8 | 49.9 |
| Redeemable preferred stock | **1.3** | 0.6 | 0.8 | 0.9 | 0.7 |
| Long-term debt [(b)] | **44.1** | 44.9 | 44.1 | 43.3 | 49.4 |
| Total (excluding amounts due within one year) | **100.0** | 100.0 | 100.0 | 100.0 | 100.0 |
| **Customers (year-end):** | | | | | |
| Residential | **153,115** | 153,172 | 153,158 | 152,453 | 152,585 |
| Commercial | **33,992** | 33,783 | 33,663 | 33,496 | 33,250 |
| Industrial | **452** | 451 | 467 | 482 | 480 |
| Other | **173** | 175 | 175 | 175 | 175 |
| Total | **187,732** | 187,581 | 187,463 | 186,606 | 186,490 |
| **Employees (year-end)** | **1,242** | 1,484 | 1,478 | 1,478 | 1,344 |

(a) A significant loss to income was recorded by the Company related to the suspension of the Kemper IGCC in June 2017. Earnings in all periods presented were impacted by losses related to the Kemper IGCC.

(b) A reclassification of debt issuance costs from Total Assets to Long-term debt of $9 million and $11 million is reflected for years 2014 and 2013, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(c) A reclassification of deferred tax assets from Total Assets of $105 million and $16 million is reflected for years 2014 and 2013, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

**SELECTED FINANCIAL AND OPERATING DATA 2013 - 2017 (continued)**
**Mississippi Power Company 2017 Annual Report**

| | 2017 | 2016 | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|
| **Operating Revenues (in millions):** | | | | | |
| Residential | $ 257 | $ 260 | $ 238 | $ 239 | $ 242 |
| Commercial | 285 | 279 | 256 | 257 | 266 |
| Industrial | 321 | 313 | 287 | 291 | 289 |
| Other | (9) | 7 | (5) | 8 | 2 |
| Total retail | 854 | 859 | 776 | 795 | 799 |
| Wholesale — non-affiliates | 259 | 261 | 270 | 323 | 294 |
| Wholesale — affiliates | 56 | 26 | 76 | 107 | 35 |
| Total revenues from sales of electricity | 1,169 | 1,146 | 1,122 | 1,225 | 1,128 |
| Other revenues | 18 | 17 | 16 | 18 | 17 |
| Total | $ 1,187 | $ 1,163 | $ 1,138 | $ 1,243 | $ 1,145 |
| **Kilowatt-Hour Sales (in millions):** | | | | | |
| Residential | 1,944 | 2,051 | 2,025 | 2,126 | 2,088 |
| Commercial | 2,764 | 2,842 | 2,806 | 2,860 | 2,865 |
| Industrial | 4,841 | 4,906 | 4,958 | 4,943 | 4,739 |
| Other | 39 | 39 | 40 | 40 | 40 |
| Total retail | 9,588 | 9,838 | 9,829 | 9,969 | 9,732 |
| Wholesale — non-affiliates | 3,672 | 3,920 | 3,852 | 4,191 | 3,929 |
| Wholesale — affiliates | 2,024 | 1,108 | 2,807 | 2,900 | 931 |
| Total | 15,284 | 14,866 | 16,488 | 17,060 | 14,592 |
| **Average Revenue Per Kilowatt-Hour (cents) (*) :** | | | | | |
| Residential | 13.22 | 12.68 | 11.75 | 11.26 | 11.59 |
| Commercial | 10.31 | 9.82 | 9.12 | 8.99 | 9.27 |
| Industrial | 6.63 | 6.38 | 5.79 | 5.89 | 6.10 |
| Total retail | 8.91 | 8.73 | 7.90 | 7.97 | 8.21 |
| Wholesale | 5.53 | 5.71 | 5.20 | 6.06 | 6.76 |
| Total sales | 7.65 | 7.71 | 6.80 | 7.18 | 7.73 |
| **Residential Average Annual Kilowatt-Hour Use Per Customer** | 12,692 | 13,383 | 13,242 | 13,934 | 13,680 |
| **Residential Average Annual Revenue Per Customer** | $ 1,680 | $ 1,697 | $ 1,556 | $ 1,568 | $ 1,585 |
| **Plant Nameplate Capacity Ratings (year-end) (megawatts)** | 3,628 | 3,481 | 3,561 | 3,867 | 3,088 |
| **Maximum Peak-Hour Demand (megawatts):** | | | | | |
| Winter | 2,390 | 2,195 | 2,548 | 2,618 | 2,083 |
| Summer | 2,322 | 2,384 | 2,403 | 2,345 | 2,352 |
| **Annual Load Factor (percent)** | 63.1 | 64.0 | 60.6 | 59.4 | 64.7 |
| **Plant Availability Fossil-Steam (percent)** | 89.1 | 91.4 | 90.6 | 87.6 | 89.3 |
| **Source of Energy Supply (percent):** | | | | | |
| Coal | 7.5 | 8.0 | 16.5 | 39.7 | 32.7 |
| Oil and gas | 88.0 | 84.9 | 81.6 | 55.3 | 57.1 |
| Purchased power — | | | | | |
| From non-affiliates | 0.5 | (0.3) | 0.4 | 1.4 | 2.0 |
| From affiliates | 4.0 | 7.4 | 1.5 | 3.6 | 8.2 |
| Total | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |

(*) The average revenue per kilowatt-hour (cents) is based on booked operating revenues and will not match billed revenue per kilowatt-hour.

# SOUTHERN POWER COMPANY

# FINANCIAL SECTION

**MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING**
**Southern Power Company and Subsidiary Companies 2017 Annual Report**

The management of Southern Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2017 .

/s/ Joseph A. Miller
Joseph A. Miller
Chairman, President, and Chief Executive Officer

/s/ William C. Grantham
William C. Grantham
Senior Vice President, Chief Financial Officer, and Treasurer

February 20, 2018

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the stockholder and the Board of Directors of Southern Power Company and Subsidiary Companies

**Opinion on the Financial Statements**

We have audited the accompanying consolidated balance sheets of Southern Power Company and Subsidiary Companies (the Company) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2017 and 2016 , the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2017 , and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements (pages II-508 to II-542 ) present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016 , and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017 , in conformity with accounting principles generally accepted in the United States of America.

**Basis for Opinion**

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 20, 2018

We have served as the Company's auditor since 2002.

**DEFINITIONS**

| Term | Meaning |
|---|---|
| Alabama Power | Alabama Power Company |
| AOCI | Accumulated other comprehensive income |
| ASC | Accounting Standards Codification |
| ASU | Accounting Standards Update |
| $CO_2$ | Carbon dioxide |
| COD | Commercial operation date |
| CWIP | Construction work in progress |
| EPA | U.S. Environmental Protection Agency |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| GAAP | U.S. generally accepted accounting principles |
| Georgia Power | Georgia Power Company |
| Gulf Power | Gulf Power Company |
| IRS | Internal Revenue Service |
| ITC | Investment tax credit |
| KWH | Kilowatt-hour |
| LTSA | Long-term service agreement |
| Mississippi Power | Mississippi Power Company |
| mmBtu | Million British thermal units |
| Moody's | Moody's Investors Service, Inc. |
| MW | Megawatt |
| MWH | Megawatt hour |
| $NO_X$ | Nitrogen oxide |
| OCI | Other comprehensive income |
| power pool | The operating arrangement whereby the integrated generating resources of the traditional electric operating companies and Southern Power (excluding subsidiaries) are subject to joint commitment and dispatch in order to serve their combined load obligations |
| PPA | Power purchase agreements, as well as contracts for differences that provide the owner of a renewable facility a certain fixed price for the electricity sold to the grid |
| PTC | Production tax credit |
| S&P | S&P Global Ratings, a division of S&P Global Inc. |
| SCS | Southern Company Services, Inc. (the Southern Company system service company) |
| SEC | U.S. Securities and Exchange Commission |
| $SO_2$ | Sulfur dioxide |
| Southern Company | The Southern Company |
| Southern Company Gas | Southern Company Gas and its subsidiaries |
| Southern Company system | Southern Company, the traditional electric operating companies, Southern Power Company, Southern Company Gas (as of July 1, 2016), Southern Electric Generating Company, Southern Nuclear, SCS, Southern Linc, PowerSecure, Inc. (as of May 9, 2016), and other subsidiaries |
| Southern Linc | Southern Communications Services, Inc. |
| Southern Nuclear | Southern Nuclear Operating Company, Inc. |
| Tax Reform Legislation | The Tax Cuts and Jobs Act, which was signed into law on December 22, 2017 and became effective on January 1, 2018 |
| traditional electric operating companies | Alabama Power, Georgia Power, Gulf Power, and Mississippi Power |

**MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS**
**Southern Power Company and Subsidiary Companies 2017 Annual Report**

## OVERVIEW

### Business Activities

Southern Power Company and its subsidiaries (the Company) develop, construct, acquire, own, and manage power generation assets, including renewable energy projects, and sell electricity at market-based rates in the wholesale market. The Company continually seeks opportunities to execute its strategy to create value through various transactions including acquisitions and sales of assets, development and construction of new generating facilities, and entry into PPAs primarily with investor-owned utilities, independent power producers, municipalities, electric cooperatives, and other load-serving entities, as well as commercial and industrial customers. In general, the Company has committed to the construction or acquisition of new generating capacity only after entering into or assuming long-term PPAs for the new facilities.

During 2017 , the Company acquired or commenced construction of approximately 424 MWs of additional wind facilities and completed construction of, and placed in service, approximately 222 MWs of solar facilities. In addition, the Company continued development of its portfolio of wind projects and continued expansion of the 345-MW Mankato natural gas facility. Subsequent to December 31, 2017 , the Company acquired Gaskell West 1, which is an approximately 20-MW solar facility. See FUTURE EARNINGS POTENTIAL – "Acquisitions" and "Construction Projects" herein for additional information.

As of December 31, 2017 , the Company's generation fleet totaled 12,940 MWs of nameplate capacity in commercial operation (including 5,152 MWs owned by its subsidiaries). The average remaining duration of the Company's total portfolio of wholesale contracts is approximately 15 years, which reduces remarketing risk for the Company. With the inclusion of the PPAs and investments associated with renewable and natural gas facilities currently under construction and acquired subsequent to December 31, 2017 , the Company has an average investment coverage ratio of 91 % through 2022 and 89 % through 2027.

The Company is pursuing the sale of a 33% equity interest in a newly-formed holding company that owns substantially all of the Company's solar assets, which, if successful, is expected to close in the middle of 2018. The ultimate outcome of this matter cannot be determined at this time.

The Company's future earnings will depend on the parameters of the wholesale market and the efficient operation of its wholesale generating assets, as well as the Company's ability to execute its growth strategy and to develop and construct generating facilities. In addition, the Company's earnings may be impacted by the availability of federal and state solar ITCs and wind PTCs on its renewable energy projects, which could be impacted by current or future potential tax reform legislation. See FUTURE EARNINGS POTENTIAL – "Acquisitions," "Construction Projects," and "Income Tax Matters" herein for additional information.

Effective in December 2017, 538 employees transferred from SCS to the Company. The Company became obligated for related employee costs including pension, other postretirement benefits, and stock-based compensation and has recognized the respective balance sheet assets and liabilities, including AOCI impacts, in its balance sheet at December 31, 2017. Prior to the transfer of employees, the Company's agreements with SCS provided for employee services rendered at amounts in compliance with FERC regulations.

To evaluate operating results and to ensure the Company's ability to meet its contractual commitments to customers, the Company continues to focus on several key performance indicators, including, but not limited to, peak season equivalent forced outage rate, contract availability, and net income.

See RESULTS OF OPERATIONS herein for information on the Company's financial performance.

### Earnings

The Company's 2017 net income was $1.1 billion , a $733 million increase from 2016 , primarily attributable to $743 million related to the Tax Reform Legislation. Also contributing to the change were increases in operating expenses and interest expense related to the Company's growth strategy and continuous construction program, largely offset by increased renewable energy sales.

The Company's 2016 net income was $338 million , a $123 million, or 57%, increase from 2015 . The increase was primarily due to increased federal income tax benefits from solar ITCs and wind PTCs and increased renewable energy sales, partially offset by increases in depreciation, operations and maintenance expenses, and interest expense from debt issuances, primarily related to new solar and wind facilities.

Benefits from solar ITCs, related to the Company's acquisition and construction of new facilities, and wind PTCs, related to wind generation, significantly impacted the Company's net income in 2017 and 2016. The Company's net income in 2015 was also significantly impacted by solar ITCs. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

## RESULTS OF OPERATIONS

A condensed statement of income follows:

| | Amount | Increase (Decrease) from Prior Year | |
|---|---|---|---|
| | **2017** | **2017** | 2016 |
| | | *(in millions)* | |
| Operating revenues | **$ 2,075** | **$ 498** | $ 187 |
| Fuel | **621** | **165** | 15 |
| Purchased power | **149** | **47** | 9 |
| Other operations and maintenance | **386** | **32** | 94 |
| Depreciation and amortization | **503** | **151** | 104 |
| Taxes other than income taxes | **48** | **25** | 1 |
| Total operating expenses | **1,707** | **420** | 223 |
| Operating income | **368** | **78** | (36) |
| Interest expense, net of amounts capitalized | **191** | **74** | 40 |
| Other income (expense), net | **1** | **(5)** | 5 |
| Income taxes (benefit) | **(939)** | **(744)** | (216) |
| Net income | **1,117** | **743** | 145 |
| Less: Net income attributable to noncontrolling interests | **46** | **10** | 22 |
| Net income attributable to the Company | **$ 1,071** | **$ 733** | $ 123 |

### *Operating Revenues*

Total operating revenues include PPA capacity revenues, which are derived primarily from long-term contracts involving natural gas and biomass generating facilities, and PPA energy revenues from the Company's generation facilities. To the extent the Company has capacity not contracted under a PPA, it may sell power into the wholesale market and, to the extent the generation assets are part of the Intercompany Interchange Contract (IIC), as approved by the FERC, it may sell power into the power pool.

*Natural Gas and Biomass Capacity and Energy Revenue*

Capacity revenues generally represent the greatest contribution to net income and are designed to provide recovery of fixed costs plus a return on investment.

Energy is generally sold at variable cost or is indexed to published natural gas indices. Energy revenues will vary depending on the energy demand of the Company's customers and their generation capacity, as well as the market prices of wholesale energy compared to the cost of the Company's energy. Energy revenues also include fees for support services, fuel storage, and unit start charges. Increases and decreases in energy revenues under PPAs that are driven by fuel or purchased power prices are accompanied by an increase or decrease in fuel and purchased power costs and do not have a significant impact on net income.

*Solar and Wind Energy Revenue*

The Company's energy sales from solar and wind generating facilities are predominantly through long-term PPAs that do not have a capacity charge. Customers either purchase the energy output of a dedicated renewable facility through an energy charge or pay a fixed price related to the energy sold to the grid. As a result, the Company's ability to recover fixed and variable operations and maintenance expenses is dependent upon the level of energy generated from these facilities, which can be impacted by weather conditions, equipment performance, transmission constraints, and other factors.

See FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" herein for additional information regarding the Company's PPAs.

Details of the Company's operating revenues were as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| PPA capacity revenues | $ 599 | $ 541 | $ 569 |
| PPA energy revenues | 970 | 694 | 560 |
| Total PPA revenues | 1,569 | 1,235 | 1,129 |
| Non-PPA revenues | 494 | 330 | 252 |
| Other revenues | 12 | 12 | 9 |
| Total operating revenues | $ 2,075 | $ 1,577 | $ 1,390 |

Operating revenues for 2017 were $2.1 billion , reflecting a $498 million , or 32%, increase from 2016 . The increase in operating revenues was primarily due to the following:

- PPA capacity revenues increased $58 million, or 11%, primarily due to additional customer capacity requirements, and a new PPA related to the Mankato natural gas facility acquired in late 2016.
- PPA energy revenues increased $276 million, or 40%, primarily due to a $213 million increase in renewable energy sales arising from new solar and wind facilities and a $50 million increase in sales from existing natural gas PPAs primarily due to an $85 million increase in the average cost of fuel, partially offset by a $35 million decrease in the volume of KWHs sold primarily due to reduced customer load.
- Non-PPA revenues increased $164 million, or 50%, primarily due to a $156 million increase in the volume of KWHs sold primarily from uncovered natural gas capacity through short-term opportunity sales, as well as an $8 million increase in the price of energy in the wholesale markets.

Operating revenues for 2016 were $1.6 billion, reflecting a $187 million, or 13%, increase from 2015 . The increase in operating revenues was primarily due to the following:

- PPA capacity revenues decreased $28 million as a result of a $44 million decrease in non-affiliate capacity revenues primarily as a result of PPA expirations and subsequent generation capacity remarketing into the short-term markets, partially offset by a $16 million increase in affiliate capacity revenues due to new PPAs.
- PPA energy revenues increased $134 million primarily due to a $170 million increase in renewable energy sales arising from new solar and wind facilities, partially offset by a decrease of $36 million in fuel revenues related to natural gas PPAs. Overall, total KWH sales under PPAs increased 7% in 2016 when compared to 2015.
- Non-PPA revenues increased $78 million primarily due to a 23% increase in KWH sales. Underlying this increase was a $113 million increase in short-term sales to non-affiliates as a result of remarketing generation capacity from expired PPAs, partially offset by a $35 million decrease in power pool sales primarily associated with a reduction in capacity available for sale.

***Fuel and Purchased Power Expenses***

Fuel costs constitute one of the largest expenses for the Company. In addition, the Company purchases a portion of its electricity needs from the wholesale market including the power pool. Details of the Company's generation and purchased power were as follows:

| | Total KWHs | Total KWH % Change | Total KWHs | Total KWH % Change |
|---|---|---|---|---|
| | 2017 | | 2016 | |
| | | *(in billions of KWHs)* | | |
| Generation | 44 | | 37 | |
| Purchased power | 5 | | 3 | |
| Total generation and purchased power | 49 | 23% | 40 | 14% |
| Total generation and purchased power, excluding solar, wind, and tolling agreements | 28 | 22% | 23 | 10% |

**MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)**
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The Company's PPAs for natural gas and biomass generation generally provide that the purchasers are responsible for either procuring the fuel (tolling agreements) or reimbursing the Company for substantially all of the cost of fuel relating to the energy delivered under such PPAs. Consequently, changes in such fuel costs are generally accompanied by a corresponding change in related fuel revenues and do not have a significant impact on net income. The Company is responsible for the cost of fuel for generating units that are not covered under PPAs. Power from these generating units is sold into the wholesale market or into the power pool for capacity owned directly by the Company.

Purchased power expenses will vary depending on demand, availability, and the cost of generating resources throughout the Southern Company system and other contract resources. Load requirements are submitted to the power pool on an hourly basis and are fulfilled with the lowest cost alternative, whether that is generation owned by the Company, an affiliate company, or external parties. Such purchased power costs are generally recovered through PPA revenues.

Details of the Company's fuel and purchased power expenses were as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| Fuel | **$ 621** | $ 456 | $ 441 |
| Purchased power | **149** | 102 | 93 |
| Total fuel and purchased power expenses | **$ 770** | $ 558 | $ 534 |

In 2017 , total fuel and purchased power expenses increased $212 million, or 38%, compared to 2016 . Fuel expense increased $165 million, or 36%, primarily due to an $83 million increase associated with the volume of KWHs generated and an $82 million increase associated with the average cost of natural gas per KWH generated. Purchased power expense increased $47 million, or 46%, primarily due to a $37 million increase associated with the volume of KWHs purchased and an $11 million increase associated with the average cost of purchased power.

In 2016 , total fuel and purchased power expenses increased $24 million, or 4%, compared to 2015 . Fuel expense increased $15 million, or 3%, primarily due to a $22 million increase associated with the volume of KWHs generated, partially offset by a $7 million decrease associated with the average cost of natural gas per KWH generated. Purchased power expense increased $9 million, or 10%, primarily due to a $53 million increase associated with the volume of KWHs purchased, partially offset by a $28 million decrease associated with the average cost of purchased power and a $16 million decrease associated with a PPA expiration.

***Other Operations and Maintenance Expenses***

In 2017 , other operations and maintenance expenses increased $32 million, or 9%, compared to 2016 . The increase was primarily due to increases of $56 million associated with new facilities, $21 million in business development and support expenses, and $6 million in employee compensation, all associated with the Company's overall growth. These increases were partially offset by decreases of $35 million associated with scheduled outage and maintenance expenses and $15 million in non-outage operations and maintenance expenses.

In 2016 , other operations and maintenance expenses increased $94 million, or 36%, compared to 2015 . The increase was primarily due to increases of $35 million associated with new plants placed in service in 2015 and 2016, $25 million associated with scheduled outage and maintenance expenses, and $21 million in business development and support expenses and $13 million in employee compensation all primarily associated with the Company's overall growth.

***Depreciation and Amortization***

In 2017 , depreciation and amortization increased $151 million, or 43%, compared to 2016 . In 2016 , depreciation and amortization increased $104 million, or 42%, compared to 2015 . These increases were primarily due to additional depreciation related to new solar, wind, and natural gas facilities placed in service. See Note 1 to the financial statements under "Depreciation" for additional information.

***Taxes Other Than Income Taxes***

In 2017 , taxes other than income taxes were $48 million compared to $23 million in 2016. In 2016 , taxes other than income taxes increased $1 million, or 5%, compared to 2015 . The increases were primarily due to additional property taxes due to new facilities.

***Interest Expense, Net of Amounts Capitalized***

In 2017 , interest expense, net of amounts capitalized increased $74 million, or 63%, compared to 2016 . The increase was primarily due to an increase of $44 million in interest expense related to an increase in average outstanding long-term debt, primarily to fund the Company's growth strategy and continuous construction program, as well as a $30 million decrease in capitalized interest associated with completing construction of and placing in service solar facilities.

In 2016 , interest expense, net of amounts capitalized increased $40 million, or 52%, compared to 2015 . The increase was primarily due to an increase of $66 million in interest expense related to additional debt issued during 2016 primarily to fund the Company's growth strategy and continuous construction program, partially offset by a $26 million increase in capitalized interest associated with the construction of solar facilities.

***Other Income (Expense), Net***

In 2017 , other income (expense), net decreased $5 million, or 83%, compared to 2016 . In 2016 , other income (expense), net increased $5 million compared to 2015 . For 2017, the amount includes $159 million from currency losses compared to $82 million from currency gains in 2016, arising from translation of €1.1 billion euro-denominated fixed-rate notes into U.S. dollars, each fully offset by an equal amount on the foreign currency hedges that were reclassified from accumulated OCI into earnings. See Note 9 to the financial statements under "Foreign Currency Derivatives" for additional information regarding hedging.

***Income Taxes (Benefit)***

In 2017 , income tax benefit was $939 million compared to $195 million for 2016 of which $743 million is related to the Tax Reform Legislation under which the Company remeasured its accumulated deferred income taxes based on the new federal income tax rates. The remaining increase in tax benefit was primarily due to an increase of $89 million in PTCs from wind generation in 2017 and other state income taxes, significantly offset by a decrease in tax benefits from lower ITCs from solar plants placed in service.

In 2016 , income tax benefit was $195 million compared to an expense of $21 million for 2015 . The $216 million change was primarily due to an increase of $180 million in federal income tax benefits related to ITCs for solar plants placed in service and PTCs from wind generation in 2016 and a $35 million decrease in tax expense related to lower pre-tax earnings in 2016 .

See FUTURE EARNINGS POTENTIAL – " Income Tax Matters – Federal Tax Reform Legislation " herein and Note 1 to the financial statements under "Income and Other Taxes" for information on how the Company recognizes the tax benefits related to federal ITCs and PTCs and Note 5 to the financial statements under "Effective Tax Rate" for additional information.

### Effects of Inflation

The Company is party to long-term contracts reflecting market-based rates, including inflation expectations. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

## FUTURE EARNINGS POTENTIAL

### General

The results of operations for the past three years are not necessarily indicative of the Company's future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's competitive wholesale business. These factors include: the Company's ability to achieve sales growth while containing costs; regulatory matters; creditworthiness of customers; total generating capacity available in the Company's market areas; the successful remarketing of capacity as current contracts expire; the Company's ability to execute its growth strategy, including successful additional investments in renewable and other energy projects, and to develop and construct generating facilities.

On December 22, 2017, the Tax Reform Legislation was signed into law and became effective on January 1, 2018, which among other things, reduces the federal corporate income tax rate to 21% and changes rates of depreciation and the business interest deduction. See " Income Tax Matters " and FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein and Note 5 to the financial statements for additional information.

In September 2017 , the Company began a legal entity reorganization of various direct and indirect subsidiaries that own and operate substantially all of the solar facilities, including certain subsidiaries owned in partnership with various third parties. The reorganization is expected to be substantially completed in the first quarter 2018. The Company is pursuing the sale of a 33% equity interest in the newly-formed holding company owning these solar assets, which, if successful, is expected to close in the middle of 2018. The ultimate outcome of this matter cannot be determined at this time.

Demand for electricity is primarily driven by the pace of economic growth that may be affected by changes in regional and global economic conditions, as well as renewable portfolio standards, which may impact future earnings. Other factors that could influence future earnings include weather, transmission constraints, cost of generation from units within the power pool, and operational limitations.

**Power Sales Agreements**

***General***

The Company has PPAs with some of Southern Company's traditional electric operating companies, other investor-owned utilities, independent power producers, municipalities, and other load-serving entities, as well as commercial and industrial customers. The PPAs are expected to provide the Company with a stable source of revenue during their respective terms.

Many of the Company's PPAs have provisions that require the Company or the counterparty to post collateral or an acceptable substitute guarantee in the event that S&P or Moody's downgrades the credit ratings of the respective company to an unacceptable credit rating or if the counterparty is not rated or fails to maintain a minimum coverage ratio. See FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein for additional information.

The Company is working to maintain and expand its share of the wholesale markets. The Company expects there to be new demand for capacity that will develop in the 2018-2020 timeframe. The size of available demand and timing will vary across the wholesale markets. The Company calculates an investment coverage ratio for its generating assets based on the ratio of investment under contract to total investment using the respective generation facilities' net book value (or expected in-service value for facilities under construction or being acquired) as the investment amount. With the inclusion of the PPAs and investments associated with the wind and natural gas facilities currently under construction and the Gaskell West 1 solar facility which was acquired subsequent to December 31, 2017 , as well as other capacity and energy contracts, the Company has an average investment coverage ratio of 91 % through 2022 and 89 % through 2027, with an average remaining contract duration of approximately 15 years. See "Acquisitions" and "Construction Projects" herein for additional information.

***Natural Gas and Biomass***

The Company's electricity sales from natural gas and biomass generating units are primarily through long-term PPAs that consist of two types of agreements. The first type, referred to as a unit or block sale, is a customer purchase from a dedicated generating unit where all or a portion of the generation from that unit is reserved for that customer. The Company typically has the ability to serve the unit or block sale customer from an alternate resource. The second type, referred to as requirements service, provides that the Company serve the customer's capacity and energy requirements from a combination of the customer's own generating units and from Company resources not dedicated to serve unit or block sales. The Company has rights to purchase power provided by the requirements customers' resources when economically viable.

As a general matter, substantially all of the PPAs provide that the purchasers are responsible for either procuring the fuel (tolling agreements) or reimbursing the Company for substantially all of the cost of fuel or purchased power relating to the energy delivered under such PPAs. To the extent a particular generating facility does not meet the operational requirements contemplated in the PPAs, the Company may be responsible for excess fuel costs. With respect to fuel transportation risk, most of the Company's PPAs provide that the counterparties are responsible for the availability of fuel transportation to the particular generating facility.

Capacity charges that form part of the PPA payments are designed to recover fixed and variable operation and maintenance costs based on dollars-per-kilowatt year. In general, to reduce the Company's exposure to certain operation and maintenance costs, the Company has LTSAs. See Note 1 to the financial statements under "Long-Term Service Agreements" for additional information.

***Solar and Wind***

The Company's electricity sales from solar and wind (renewables) generating facilities are also made pursuant to long-term PPAs; however, these solar and wind PPAs do not have a capacity charge and customers either purchase the energy output of a dedicated renewable facility through an energy charge or provide the Company a certain fixed price for the electricity sold to the grid. As a result, the Company's ability to recover fixed and variable operation and maintenance expenses is dependent upon the level of energy generated from these facilities, which can be impacted by weather conditions, equipment performance, transmission constraints, and other factors. Generally, under the solar and wind generation PPAs, the purchasing party retains the right to keep or resell the renewable energy credits.

**Environmental Matters**

The Company's operations are regulated by state and federal environmental agencies through a variety of laws and regulations governing air, water, land, and protection of other natural resources. The Company maintains a comprehensive environmental compliance strategy to assess upcoming requirements and compliance costs associated with these environmental laws and regulations. The costs, including capital expenditures and operations and maintenance costs, required to comply with environmental laws and regulations may impact results of operations, cash flows, and financial condition. Compliance costs may result from the installation of additional environmental controls. The ultimate impact of the environmental laws and regulations discussed below will depend on various factors, such as state adoption and implementation of requirements, the availability and cost of any deployed control technology, and the outcome of pending and/or future legal challenges.

New or revised environmental laws and regulations could affect many areas of the Company's operations. The Company's PPAs generally contain provisions that permit charging the counterparty with some of the new costs incurred as a result of changes in environmental laws and regulations.

Since the Company's units are newer natural gas and renewable generating facilities, costs associated with environmental compliance for these facilities have been less significant than for similarly situated coal or older natural gas generating facilities. Environmental, natural resource, and land use concerns, including the applicability of air quality limitations, the potential presence of wetlands or threatened and endangered species, the availability of water withdrawal rights, uncertainties regarding aesthetic impacts such as increased light or noise, and concerns about potential adverse health impacts can, however, increase the cost of siting and operating any type of future electric generating facility. The impact of such laws and regulations on the Company and subsequent recovery through PPA provisions cannot be determined at this time.

***Environmental Laws and Regulations***

*Air Quality*

In 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) and its $NO_X$ annual, $NO_X$ seasonal, and $SO_2$ annual programs. CSAPR is an emissions trading program that addresses the impacts of the interstate transport of $SO_2$ and $NO_X$ emissions from fossil fuel-fired power plants located in upwind states in the eastern half of the U.S. on air quality in downwind states. The Company has fossil fuel-fired generation subject to these requirements. In October 2016, the EPA published a final rule that revised the CSAPR seasonal $NO_X$ program, establishing more stringent $NO_X$ emissions budgets in Alabama and Texas . The EPA also removed North Carolina from the CSAPR $NO_X$ seasonal program and completely removed Florida from all CSAPR programs. Georgia's seasonal $NO_X$ budget remains unchanged. Increases in either future fossil fuel-fired generation or the cost of CSAPR allowances could have a negative financial impact on results of operations for the Company .

In 2015, the EPA published a final rule requiring certain states (including Alabama, Florida, Georgia, North Carolina, and Texas) to revise or remove the provisions of their state implementation plans (SIP) regulating excess emissions at industrial facilities, including electric generating facilities, during periods of startup, shut-down, or malfunction (SSM). The state excess emission rules provide necessary operational flexibility to affected units during periods of SSM and, if removed, could affect unit availability and result in increased operations and maintenance costs for the Company.

*Water Quality*

In 2014, the EPA finalized requirements under Section 316(b) of the Clean Water Act (CWA) to regulate cooling water intake structures at existing power plants and manufacturing facilities in order to minimize their effects on fish and other aquatic life. The regulation requires plant-specific studies to determine applicable measures to protect organisms that either get caught on the intake screens (impingement) or are drawn into the cooling system (entrainment). The ultimate impact of this rule will depend on the outcome of these plant-specific studies and any additional protective measures required to be incorporated into each plant's National Pollutant Discharge Elimination System (NPDES) permit based on site-specific factors.

In 2015, the EPA finalized the steam electric effluent limitations guidelines (ELG) rule that set national standards for wastewater discharges from steam electric generating units. The rule prohibits effluent discharges of certain wastestreams and imposes stringent arsenic, mercury, selenium, and nitrate/nitrite limits on scrubber wastewater discharges. The revised technology-based limits and compliance dates may require extensive modifications to existing wastewater management systems or the installation and operation of new wastewater management systems. Compliance with the ELG rule is expected to require capital expenditures and increased operational costs. Compliance applicability dates range from November 1, 2018 to December 31, 2023 with state environmental agencies' incorporating specific applicability dates in the NPDES permitting process based on information provided for each waste stream. The EPA has committed to a new rulemaking that could potentially revise the limitations and applicability dates of the ELG rule. The EPA expects to finalize this rulemaking in 2020.

In 2015, the EPA and the U.S. Army Corps of Engineers (Corps) jointly published a final rule that revised the regulatory definition of waters of the United States (WOTUS) for all CWA programs. The rule significantly expanded the scope of federal jurisdiction over waterbodies (such as rivers, streams, and canals), which could impact new generation projects . On July 27, 2017, the EPA and the Corps proposed to rescind the 2015 WOTUS rule. The WOTUS rule has been stayed by the U.S. Court of Appeals for the Sixth Circuit since late 2015, but on January 22, 2018, the U.S. Supreme Court determined that federal district courts have jurisdiction over the pending challenges to the rule. On February 6, 2018, the EPA and the Corps published a final rule delaying implementation of the 2015 WOTUS rule to 2020.

***Global Climate Issues***

In 2015, the EPA published final rules limiting $CO_2$ emissions from new, modified, and reconstructed fossil fuel-fired electric generating units and guidelines for states to develop plans to meet EPA-mandated $CO_2$ emission performance standards for existing units (known as the Clean Power Plan or CPP). In February 2016, the U.S. Supreme Court granted a stay of the CPP, which will remain in effect through the resolution of litigation in the U.S. Court of Appeals for the District of Columbia challenging the legality of the CPP and any review by the U.S. Supreme Court. On March 28, 2017, the U.S. President signed an executive order directing agencies to review actions that potentially burden the development or use of domestically produced energy resources, including review of the CPP and other $CO_2$ emissions rules. On October 10, 2017, the EPA published a proposed rule to repeal the CPP and, on December 28, 2017, published an advanced notice of proposed rulemaking regarding a CPP replacement rule.

In 2015, parties to the United Nations Framework Convention on Climate Change, including the United States, adopted the Paris Agreement, which established a non-binding universal framework for addressing greenhouse gas (GHG) emissions based on nationally determined contributions. On June 1, 2017, the U.S. President announced that the United States would withdraw from the Paris Agreement and begin renegotiating its terms. The ultimate impact of this agreement or any renegotiated agreement depends on its implementation by participating countries.

The EPA's GHG reporting rule requires annual reporting of GHG emissions expressed in terms of metric tons of $CO_2$ equivalent emissions for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2016 GHG emissions were approximately 13 million metric tons of $CO_2$ equivalent. The preliminary estimate of the Company's 2017 GHG emissions on the same basis is approximately 13 million metric tons of $CO_2$ equivalent.

**Income Tax Matters**

***Consolidated Income Taxes***

On behalf of the Company, Southern Company files a consolidated federal income tax return and various state income tax returns, some of which are combined, unitary, or consolidated. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

The impact of certain tax events at Southern Company and/or its other subsidiaries can, and does, affect the Company's ability to utilize certain tax credits. See "Tax Credits" and ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" herein and Note 5 to the financial statements for additional information.

The Company currently has unutilized federal ITC and PTC carryforwards totaling approximately $2.0 billion , and thus anticipates utilizing third-party tax equity partnerships as one of the financing sources to fund its renewable growth strategy where the tax partner will take significantly all of the respective federal tax benefits. These tax equity partnerships are expected to be consolidated in the Company's financial statements using a hypothetical liquidation at book value (HLBV) methodology to allocate partnership gains and losses to the Company.

***Federal Tax Reform Legislation***

On December 22, 2017, the Tax Reform Legislation was signed into law and became effective on January 1, 2018. The Tax Reform Legislation, among other things, reduces the federal corporate income tax rate to 21%, retains normalization provisions for public utility property and existing renewable energy incentives, and repeals the corporate alternative minimum tax.

For businesses other than regulated utilities, the Tax Reform Legislation allows 100% bonus depreciation of qualified property acquired and placed in service between September 28, 2017 and January 1, 2023 and phases down 20% each year until it completely phases out for qualified property placed in service after December 31, 2027. Further, the business interest deduction is limited to 30% of taxable income excluding interest, net operating loss (NOL) carryforward, and depreciation and amortization through December 31, 2021 and thereafter to 30% of taxable income excluding interest and NOL carryforwards.

In addition, under the Tax Reform Legislation, NOLs generated after December 31, 2017 can no longer be carried back to previous tax years but can be carried forward indefinitely, with utilization limited to 80% of taxable income of the subsequent tax year. The projected reduction of Southern Company's consolidated income tax liability resulting from the tax rate reduction also delays the expected utilization of existing tax credit carryforwards.

For the year ended December 31, 2017, implementation of the Tax Reform Legislation resulted in an estimated net tax benefit of $743 million, primarily due to the impact of the reduction of the corporate income tax rate on deferred tax assets and liabilities .

The Tax Reform Legislation is subject to further interpretation and guidance from the IRS, as well as each respective state's adoption. In addition, the regulatory treatment of certain impacts of the Tax Reform Legislation is subject to the discretion of the FERC.

See FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein and Note 5 to the financial statements under "Current and Deferred Income Taxes" for additional information.

The ultimate outcome of these matters cannot be determined at this time.

***Tax Credits***

The Tax Reform Legislation retained the renewable energy incentives that were included in the Protecting Americans from Tax Hikes (PATH) Act. The PATH Act allows for 30% ITC for solar projects that commence construction by December 31, 2019; 26% ITC for solar projects that commence construction in 2020; 22% ITC for solar projects that commence construction in 2021; and a permanent 10% ITC for solar projects that commence construction on or after January 1, 2022. In addition, the PATH Act allows for 100% PTC for wind projects that commenced construction in 2016; 80% PTC for wind projects that commenced construction in 2017; 60% PTC for wind projects that commence construction in 2018; and 40% PTC for wind projects that commence construction in 2019. Wind projects commencing construction after 2019 will not be entitled to any PTCs. The Company has received ITCs related to its investment in new solar facilities acquired or constructed and receives PTCs related to the first 10 years of energy production from its wind facilities, which have had, and will continue to have, a material impact on the Company's cash flows and net income. At December 31, 2017, the Company had approximately $2.0 billion of unutilized ITCs and PTCs, which are currently expected to be fully utilized by 2027, but could be further delayed as a result of the Company's continued growth strategy, as well as the impacts from the Tax Reform Legislation. See Note 1 to the financial statements under "Income and Other Taxes" and Note 5 to the financial statements under "Current and Deferred Income Taxes – Tax Credit Carryforwards" and "Effective Tax Rate" for additional information regarding utilization and amortization of credits and the tax benefit related to basis differences.

***Bonus Depreciation***

Under the Tax Reform Legislation, projects with binding contracts prior to September 28, 2017 and placed in service after September 27, 2017 remain eligible for bonus depreciation under the PATH Act. The PATH Act allowed for 50% bonus depreciation for 2015 through 2017, 40% bonus depreciation for 2018, and 30% bonus depreciation for 2019 and certain long-lived assets placed in service in 2020. Based on provisional estimates, approximately $130 million of positive cash flows is expected to result from bonus depreciation for the 2017 tax year. Should Southern Company have a NOL in 2018, all of these cash flows may not be fully realized in 2018. In addition, any cash flows resulting from bonus depreciation will also be impacted by the Company's use of third-party tax equity arrangements. See Note 5 to the financial statements under "Current and Deferred Income Taxes" for additional information. The ultimate outcome of these matters cannot be determined at this time.

***Legal Entity Reorganization***

In September 2017 , the Company began a legal entity reorganization of various direct and indirect subsidiaries that own and operate substantially all of the solar facilities, including certain subsidiaries owned in partnership with various third parties. The reorganization included the purchase of all of the redeemable noncontrolling interests, representing 10% of the membership interests, in Southern Turner Renewable Energy, LLC. The reorganization is expected to be substantially completed in the first quarter 2018 and is expected to result in estimated tax benefits totaling between $50 million and $55 million related to certain changes in state apportionment rates and net operating loss carryforward utilization that will be recorded in the first quarter 2018. The Company is pursuing the sale of a 33% equity interest in the newly-formed holding company owning these solar assets. The ultimate outcome of this matter cannot be determined at this time.

### Acquisitions

During 2017 and subsequent to December 31, 2017, in accordance with its overall growth strategy, the Company acquired the projects discussed below, as well as the Cactus Flats wind facility discussed under "Construction Projects" herein. See Note 11 to the financial statements for additional information.

| Project Facility | Resource | Seller, Acquisition Date | Approximate Nameplate Capacity ( *MW* ) | Location | Percentage Ownership | Actual/Expected COD | PPA Counterparties | PPA Contract Period |
|---|---|---|---|---|---|---|---|---|
| **Business Acquisitions During the Year Ended December 31, 2017** | | | | | | | | |
| Bethel | Wind | Invenergy Wind Global LLC, January 6, 2017 | 276 | Castro County, TX | 100% | January 2017 | Google Energy, LLC | 12 years |
| **Asset Acquisitions Subsequent to December 31, 2017** | | | | | | | | |
| Gaskell West 1 | Solar | Recurrent Energy Development Holdings, LLC , January 26, 2018 | 20 | Kern County, CA | 100% of Class B (*) | March 2018 | Southern California Edison | 20 years |

(*) The Company owns 100% of the class B membership interest under a tax equity partnership agreement.

### Construction Projects

#### *Construction Projects Completed and in Progress*

During 2017, in accordance with its overall growth strategy, the Company completed construction of and placed in service, or continued construction of, the projects set forth in the table below.

| Project Facility | Resource | Approximate Nameplate Capacity ( *MW* ) | Location | Ownership Percentage | Actual / Expected COD | PPA Counterparties | PPA Contract Period |
|---|---|---|---|---|---|---|---|
| **Construction Projects Completed During the Year Ended December 31, 2017** | | | | | | | |
| East Pecos | Solar | 120 | Pecos County, TX | 100% | March 2017 | Austin Energy | 15 years |
| Lamesa | Solar | 102 | Dawson County, TX | 100% | April 2017 | City of Garland, Texas | 15 years |
| **Projects Under Construction at December 31, 2017** | | | | | | | |
| Cactus Flats | Wind | 148 | Concho County, TX | 100% (*) | Third quarter 2018 | General Motors and General Mills | 12 years and 15 years |
| Mankato Expansion | Natural Gas | 345 | Mankato, MN | 100% | Second quarter 2019 | Northern States Power Company | 20 years |

(*) On July 31, 2017, the Company purchased 100% of the Cactus Flats facility and commenced construction. Upon placing the facility in service, the Company expects to close on a tax equity partnership agreement that has already been executed, subject to various customary conditions at closing, and will then own 100% of the class B membership interests.

Total aggregate construction costs for projects under construction at December 31, 2017, excluding acquisition costs and including construction costs to complete the subsequently-acquired Gaskell West 1 solar project, are expected to be between $385 million and $430 million . At December 31, 2017 , total costs of construction incurred for these projects was $188 million , all of which remained in CWIP.

#### *Development Projects*

During 2017, as part of the Company's renewable development strategy, the Company purchased wind turbine equipment from Siemens Wind Power, Inc. and Vestas-American Wind Technology, Inc. to be used for various development and construction projects, up to 900 MWs in total. Once these wind projects reach commercial operations, which is expected in 2021, they are expected to qualify for 80% PTCs.

During 2016, the Company entered into a joint development agreement with Renewable Energy Systems Americas, Inc. to develop and construct approximately 3,000 MWs of wind projects expected to be placed in service between 2018 and 2020. In addition, in 2016, the Company purchased wind turbine equipment from Siemens Wind Power, Inc. and Vestas-American Wind Technology, Inc. to be used for construction of the facilities. Once these wind projects reach commercial operations, they are expected to qualify for 100% PTCs.

The ultimate outcome of these matters cannot be determined at this time.

### FERC Matters

The Company has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies and the Company filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In 2015, the FERC issued an order finding that the traditional electric operating companies' and the Company's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The FERC directed the traditional electric operating companies and the Company to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional electric operating companies and the Company filed a request for rehearing and filed their response with the FERC in 2015.

In December 2016, the traditional electric operating companies and the Company filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' and the Company's potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. On May 17, 2017, the FERC accepted the traditional electric operating companies' and the Company's compliance filing accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

On October 25, 2017, the FERC issued an order in response to the traditional electric operating companies' and the Company's June 29, 2017 triennial updated market power analysis. The FERC directed the traditional electric operating companies and the Company to show cause within 60 days why market-based rate authority should not be revoked in certain areas adjacent to the area presently under mitigation in accordance with the February 2, 2017 order or to provide a mitigation plan to further address market power concerns. On November 10, 2017, the traditional electric operating companies and the Company responded to the FERC and proposed to resolve matters by applying the alternative mitigation authorized by the February 2, 2017 order to the adjacent areas made the subject of the October 25, 2017 order.

The ultimate outcome of these matters cannot be determined at this time.

### Other Matters

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as standards for air, water, land, and protection of other natural resources, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by $CO_2$ and other emissions and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters.

The ultimate outcome of such pending or potential litigation or regulatory matters cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

During 2015, the Company indirectly acquired a 51% membership interest in RE Roserock LLC (Roserock), the owner of the Roserock facility in Pecos County, Texas, which was under construction by Recurrent Energy, LLC and was subsequently placed in service in November 2016. Prior to placing the facility in service, certain solar panels were damaged during installation. While the facility currently is generating energy consistent with operational expectations and PPA obligations, the Company is pursuing remedies under its insurance policies and other contracts to repair or replace these solar panels. In connection therewith, the Company is withholding payments of approximately $26 million from the construction contractor, who has placed a lien on the

Roserock facility for the same amount. The amounts withheld are included in other accounts payable and other current liabilities on the Company's consolidated balance sheets. On May 18, 2017, Roserock filed a lawsuit in the state district court in Pecos County, Texas, against XL Insurance America, Inc. (XL) and North American Elite Insurance Company (North American Elite) seeking recovery from an insurance policy for damages resulting from a hail storm and certain installation practices by the construction contractor, McCarthy Building Companies, Inc. (McCarthy). On May 19, 2017, Roserock filed a separate lawsuit against McCarthy in the state district court in Travis County, Texas alleging breach of contract and breach of warranty for the damages sustained at the Roserock facility, which has since been moved to the U.S. District Court for the Western District of Texas. On May 22, 2017, McCarthy filed a counter lawsuit against Roserock, Array Technologies, Inc., Canadian Solar (USA), Inc., XL, and North American Elite in the U.S. District Court for the Western District of Texas alleging, among other things, breach of contract, and requesting foreclosure of mechanic's liens against Roserock. On July 18, 2017, the U.S. District Court for the Western District of Texas consolidated the two pending lawsuits. On December 11, 2017, the U.S. District Court for the Western District of Texas dismissed McCarthy's claims against Canadian Solar (USA), Inc. and dismissed cross-claims that XL and North American Elite had sought to bring against Roserock. The Company intends to vigorously pursue and defend these matters, the ultimate outcome of which cannot be determined at this time.

## ACCOUNTING POLICIES

### Application of Critical Accounting Policies and Estimates

The Company prepares its consolidated financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

***Revenue Recognition***

The Company's revenue recognition depends on appropriate classification and documentation of transactions in accordance with GAAP. In general, the Company's power sale transactions, which include PPAs, can be classified in one of four categories: leases, non-derivatives or normal sale derivatives, derivatives designated as cash flow hedges, and derivatives not designated as hedges. For more information on derivative transactions, see FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" herein and Notes 1 and 9 to the financial statements. The Company's revenues are dependent upon significant judgments used to determine the appropriate transaction classification, which must be documented upon the inception of each contract.

*Lease Transactions*

The Company considers the following factors to determine whether the sales contract is a lease:

- Assessing whether specific property is explicitly or implicitly identified in the agreement;
- Determining whether the fulfillment of the arrangement is dependent on the use of the identified property; and
- Assessing whether the arrangement conveys to the purchaser the right to use the identified property.

If the contract meets the above criteria for a lease, the Company performs further analysis as to whether the lease is classified as operating, financing, or sales-type. All of the Company's power sales contracts that are determined to be leases are accounted for as operating leases and the capacity revenue is recognized on a straight-line basis over the term of the contract and is included in the Company's operating revenues. Energy revenues and other contingent revenues are recognized in the period the energy is delivered or the service is rendered.

*Non-Derivative and Normal Sale Derivative Transactions*

If the power sales contract is not classified as a lease, the Company further considers the following factors to determine proper classification:

- Assessing whether the contract meets the definition of a derivative;
- Assessing whether the contract meets the definition of a capacity contract;
- Assessing the probability at inception and throughout the term of the individual contract that the contract will result in physical delivery; and
- Ensuring that the contract quantities do not exceed available generating capacity (including purchased capacity).

Contracts that do not meet the definition of a derivative or are designated as normal sales (i.e. capacity contracts which provide for the sale of electricity that involve physical delivery in quantities within the Company's available generating capacity) are accounted for as executory contracts. The related capacity revenue, if any, is recognized on an accrual basis in amounts equal to the lesser of the cumulative levelized amount or the cumulative amount billable under the contract over the respective contract periods. Revenues related to energy and ancillary services are recognized in the period the energy is delivered or the service is rendered.

*Cash Flow Hedge Transactions*

The Company further considers the following in designating other derivative contracts for the sale of electricity as cash flow hedges of anticipated sale transactions:

- Identifying the hedging instrument, the forecasted hedged transaction, and the nature of the risk being hedged; and
- Assessing hedge effectiveness at inception and throughout the contract term.

These contracts are accounted for on a fair value basis and are recorded in AOCI over the life of the contract. Realized gains and losses are then recognized in operating revenues as incurred.

*Mark-to-Market Transactions*

Contracts for sales of electricity, which meet the definition of a derivative and that either do not qualify or are not designated as normal sales or as cash flow hedges, are accounted for on a fair value basis and are recorded in operating revenues.

***Impairment of Long-Lived Assets and Intangibles***

The Company's investments in long-lived assets are primarily generation assets, whether in service or under construction. The Company's intangible assets arise from certain acquisitions and consist of acquired PPAs, which are amortized to revenue over the term of the respective PPAs. The Company evaluates the carrying value of these assets whenever indicators of potential impairment exist. Examples of impairment indicators could include significant changes in construction schedules, current period losses combined with a history of losses or a projection of continuing losses, a significant decrease in market prices, and the inability to remarket generating capacity for an extended period. If an indicator exists, the asset is tested for recoverability by comparing the asset carrying value to the sum of the undiscounted expected future cash flows directly attributable to the asset. If the estimate of undiscounted future cash flows is less than the carrying value of the asset, the fair value of the asset is determined and a loss is recorded. A high degree of judgment is required in developing estimates related to these evaluations, which are based on projections of various factors, including the following:

- Future demand for electricity based on projections of economic growth and estimates of available generating capacity;
- Future power and natural gas prices, which have been quite volatile in recent years; and
- Future operating costs.

***Acquisition Accounting***

The Company may acquire generation assets as part of its overall growth strategy. At the time of an acquisition, the Company will assess if these assets and activities meet the definition of a business. For acquisitions that meet the definition of a business, the Company includes operating results from the date of acquisition in its consolidated financial statements. The purchase price, including any contingent consideration, is allocated based on the fair value of the identifiable assets acquired and liabilities assumed (including any intangible assets). Assets acquired that do not meet the definition of a business are accounted for as an asset acquisition.

The purchase price of each asset acquisition is allocated based on the relative fair value of assets acquired. Determining the fair value of assets acquired and liabilities assumed requires management judgment and the Company may engage independent valuation experts to assist in this process. Fair values are determined by using market participant assumptions, and typically include the timing and amounts of future cash flows, incurred construction costs, the nature of acquired contracts, discount rates, power market prices, and expected asset lives. Any due diligence or transition costs incurred by the Company for potential or successful acquisitions are expensed as incurred.

Contingent consideration primarily relates to fixed amounts due to the seller once the facility is placed in service. For contingent consideration with variable payments, the Company fair values the arrangement with any changes recorded in the consolidated statements of income. See Note 8 to the financial statements for additional fair value information.

***Accounting for Income Taxes***

The consolidated income tax provision and deferred income tax assets and liabilities, as well as any unrecognized tax benefits and valuation allowances, require significant judgment and estimates. These estimates are supported by historical tax return data, reasonable projections of taxable income, and interpretations of applicable tax laws and regulations across multiple taxing jurisdictions. The effective tax rate reflects the statutory tax rates and calculated apportionments for the various states in which the Company operates.

On behalf of the Company, Southern Company files a consolidated federal income tax return and various state income tax returns, some of which are combined or unitary. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. Certain deductions and credits can be limited at the consolidated or combined level resulting in NOL and tax credit carryforwards that would not otherwise result on a stand-alone basis. Utilization of NOL and tax credit carryforwards and the assessment of valuation allowances are based on significant judgment and extensive analysis of the Company's, as well as Southern Company's, current financial position and result of operations, including currently available information about future years, to estimate when future taxable income will be realized.

Current and deferred state income tax liabilities and assets are estimated based on laws of multiple states that determine the income to be apportioned to their jurisdictions. States utilize various formulas to calculate the apportionment of taxable income, primarily using sales, assets, or payroll within the jurisdiction compared to the consolidated totals. In addition, each state varies as to whether a stand-alone, combined, or unitary filing methodology is required. The calculation of deferred state taxes considers apportionment factors and filing methodologies that are expected to apply in future years. The apportionments and methodologies which are ultimately finalized in a manner inconsistent with expectations could have a material effect on the Company's financial statements.

Given the significant judgment involved in estimating NOL and tax credit carryforwards and multi-state apportionments for all subsidiaries, the Company considers state deferred income tax liabilities and assets to be critical accounting estimates.

***Federal Tax Reform Legislation***

Following the enactment of the Tax Reform Legislation, the SEC staff issued Staff Accounting Bulletin 118 – "Income Tax Accounting Implications of the Tax Cuts and Jobs Act" (SAB 118), which provides for a measurement period of up to one year from the enactment date to complete accounting under GAAP for the tax effects of the legislation. Due to the complex and comprehensive nature of the enacted tax law changes, and their application under GAAP, the Company considers all amounts recorded in the financial statements as a result of the Tax Reform Legislation to be "provisional" as discussed in SAB 118 and subject to revision. The Company is awaiting additional guidance from industry and income tax authorities in order to finalize its accounting. The ultimate impact of the Tax Reform Legislation on deferred income tax assets and liabilities cannot be determined at this time. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation" herein and Note and 5 to the financial statements under "Current and Deferred Income Taxes" for additional information.

**Recently Issued Accounting Standards**

***Revenue***

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers* (ASC 606), replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the new standard is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

The Company has completed the evaluation of all revenue streams and determined that the adoption of ASC 606 will not change the current timing or amounts of revenue recognized in the Company's financial statements. Some contractual arrangements, such as certain capacity and energy payments, are excluded from the scope of ASC 606 and included in the scope of the current leasing guidance or the current derivative guidance.

The new standard is effective for reporting periods beginning after December 15, 2017. The Company applied the modified retrospective method of adoption effective January 1, 2018. The Company also utilized practical expedients which allowed it to apply the standard to open contracts at the date of adoption and to reflect the aggregate effect of all modifications when identifying performance obligations and allocating the transaction price for contracts modified before the effective date. The adoption of ASC 606 did not result in a cumulative adjustment.

***Leases***

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged . ASU 2016-02 is effective for fiscal years beginning after December 15, 2018 and the Company will adopt the new standard effective January 1, 2019.

The Company is currently implementing an information technology system along with the related changes to internal controls and accounting policies that will support the accounting for leases under ASU 2016-02. In addition, the Company has substantially completed a detailed inventory and analysis of its leases where the majority relate to land leases for its renewable generation facilities. While the Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet for lessee arrangements.

***Other***

In November 2016, the FASB issued ASU No. 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash* (ASU 2016-18). ASU 2016-18 eliminates the need to reflect transfers between cash and restricted cash in operating, investing, and financing activities in the statement of cash flows. Upon adoption, the net change in cash and cash equivalents during the period will include amounts generally described as restricted cash or restricted cash equivalents. ASU 2016-18 is effective for fiscal years beginning after December 15, 2017, and will be applied retrospectively to each period presented. The Company adopted ASU 2016-18 effective January 1, 2018 with no material impact on its financial statements.

On March 10, 2017, the FASB issued ASU No. 2017-07, *Compensation - Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017-07). ASU 2017-07 requires that an employer report the service cost component in the same line item or items as other compensation costs and requires the other components of net periodic pension and postretirement benefit costs to be separately presented in other income (expense) in the income statement. Additionally, only the service cost component related to construction labor is eligible for capitalization, when applicable. The Company adopted ASU 2017-07 which is effective for periods beginning after December 15, 2017; however, since the Company only became a sponsor of a qualified pension plan and postretirement benefit plan in December 2017, no retrospective presentation of net periodic benefits costs for 2016 or 2017 is required. See Note 2 to the financial statements for additional information.

On August 28, 2017, the FASB issued ASU No. 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities* (ASU 2017-12), amending the hedge accounting recognition and presentation requirements. ASU 2017-12 makes more financial and non-financial hedging strategies eligible for hedge accounting, amends the related presentation and disclosure requirements, and simplifies hedge effectiveness assessment requirements. ASU 2017-12 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

## FINANCIAL CONDITION AND LIQUIDITY

### Overview

The Company's financial condition remained stable at December 31, 2017 . The Company's cash requirements primarily consist of funding ongoing business operations, common stock dividends, distributions to noncontrolling interests, capital expenditures, and debt maturities. Capital expenditures and other investing activities may include investments in acquisitions or new construction associated with the Company's overall growth strategy and to maintain the existing generation fleet's performance. Operating cash flows, which may include the utilization of tax credits, will only provide a portion of the Company's cash needs. For the three-year period from 2018 through 2020, the Company's projected dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt issuances, borrowings from financial institutions, and equity contributions from Southern Company. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit agreements as needed to meet its future capital and liquidity needs. See "Sources of Capital" herein for additional information on lines of credit.

The Company also anticipates utilizing third-party tax equity partnerships as one of the financing sources to fund its renewable growth strategy where the tax partner will take significantly all of the federal tax benefits. These tax equity partnerships are expected to be consolidated in the Company's financial statements using a HLBV methodology to allocate partnership gains and losses to the Company. The Company recently secured third-party tax equity funding for the Cactus Flats project subject to achieving commercial operation and various other customary conditions to closing as well as for the Gaskell West 1 project. The ultimate outcome of these matters cannot be determined at this time.

In addition, the Company is pursuing the sale of a 33% equity interest in a newly-formed holding company that owns substantially all of the Company's solar assets, which, if successful, is expected to close in the middle of 2018. Proceeds from the sale may be used for debt redemptions, common stock dividends, working capital, and general corporate purposes as well to support the Company's continuing growth strategy.

Net cash provided from operating activities totaled $1.2 billion in 2017 , an increase of $816 million compared to 2016 . The increase in net cash provided from operating activities was primarily due to income tax refunds received and an increase in energy sales from new solar and wind facilities, partially offset by an increase in interest paid. As of December 31, 2017 , the Company had $2.0 billion of unutilized ITCs and PTCs which are not expected to be fully utilized until 2027. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Tax Credits" herein for additional information. Net cash provided from operating activities totaled $339 million in 2016 , a decrease of $664 million compared to 2015 primarily due to an increase in unutilized ITCs and PTCs.

Net cash used for investing activities totaled $1.6 billion , $4.8 billion , and $2.5 billion in 2017 , 2016 , and 2015 , respectively, and was primarily due to acquisitions and the construction of renewable and natural gas facilities. See FUTURE EARNINGS POTENTIAL – "Acquisitions" and "Construction Projects" herein for additional information.

Net cash used for financing activities totaled $502 million in 2017 primarily due to payments of common stock dividends and distributions to noncontrolling interests. Net cash provided from financing activities totaled $4.7 billion in 2016 primarily due to the issuance of additional senior notes and capital contributions from Southern Company and noncontrolling interests. Net cash provided from financing activities totaled $2.3 billion in 2015 primarily due to the issuance of additional senior notes and a 13-month term loan.

Significant balance sheet changes include a $1.0 billion increase in plant in service primarily due to new solar and wind facilities being acquired or placed in service, a $284 million increase in deferred income taxes primarily due to additional unutilized PTCs, and a $113 million increase in CWIP primarily due to the construction of a new wind facility and the Mankato natural gas expansion project. In addition, ITC benefits that are deferred and amortized over the asset lives increased $45 million as a result of additional ITCs from new solar facilities being placed in service, offset by ongoing ITC amortization. Other significant changes include a $970 million decrease in cash and cash equivalents and a $456 million decrease in acquisitions payable.

**Sources of Capital**

The Company plans to obtain the funds required for acquisitions, construction, development, debt maturities, and other purposes from operating cash flows, external securities issuances, borrowings from financial institutions, tax equity partnership contributions, and equity contributions from Southern Company. The Company also plans to utilize funds resulting from any potential sale of a 33% equity interest in substantially all of its solar asset portfolio, if completed. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors. With respect to the public offering of securities, the Company (excluding its subsidiaries) issues and offers debt registered on registration statements filed with the SEC under the Securities Act of 1933, as amended.

At December 31, 2017, the Company's current liabilities exceeded current assets by $474 million due to long-term debt maturing in the next 12 months, the use of short-term debt as a funding source, and fluctuations in cash needs, due to both seasonality and the stage of acquisitions and construction projects. The Company believes the need for working capital can be adequately met by utilizing the commercial paper program, the Facility (as defined below), borrowings from financial institutions, the debt capital markets, the commercial paper program, and operating cash flows.

The Company obtains financing separately without credit support from any affiliate. To meet liquidity and capital resource requirements, the Company had cash and cash equivalents of approximately $129 million at December 31, 2017 .

The Company's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes, including maturing debt. The Company's subsidiaries are not issuers under the commercial paper program.

Details of commercial paper were as follows:

| | Commercial Paper at the End of the Period | | Commercial Paper During the Period (*) | | |
|---|---|---|---|---|---|
| | Amount Outstanding | Weighted Average Interest Rate | Average Amount Outstanding | Weighted Average Interest Rate | Maximum Amount Outstanding |
| | *(in millions)* | | *(in millions)* | | *(in millions)* |
| **December 31, 2017** | **$ 105** | **2.0%** | **$ 232** | **1.4%** | **$ 628** |
| December 31, 2016 | $ — | N/A | $ 56 | 0.8% | $ 310 |
| December 31, 2015 | $ — | N/A | $ 166 | 0.5% | $ 385 |

(*) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2017 , 2016 , and 2015 .

### *Company Credit Facilities*

At December 31, 2017 , the Company had a committed credit facility (Facility) of $ 750 million expiring in 2022, of which $ 22 million has been used for letters of credit and $ 728 million remains unused. In May 2017, the Company amended the Facility, which, among other things, extended the maturity date from 2020 to 2022 and increased the Company's borrowing ability under this Facility to $750 million from $600 million . The Company's subsidiaries are not borrowers under the Facility. Proceeds from the Facility may be used for working capital and general corporate purposes as well as liquidity support for the Company's commercial paper program. Subject to applicable market conditions, the Company expects to renew or replace the Facility, as needed, prior to expiration. In connection therewith, the Company may extend the maturity date and/or increase or decrease the lending commitment thereunder. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Facility, as well as the Company's term loan agreements, contains a covenant that limits the ratio of debt to capitalization (as defined in the Facility) to a maximum of 65% and contains a cross-default provision that is restricted only to indebtedness of the Company. For purposes of this definition, debt excludes any project debt incurred by certain subsidiaries of the Company to the extent such debt is non-recourse to the Company, and capitalization excludes the capital stock or other equity attributable to such subsidiary. The Company is currently in compliance with all covenants in the Facility.

The Company also has a $120 million continuing letter of credit facility expiring in 2019 for standby letters of credit. At December 31, 2017, $101 million has been used for letters of credit, primarily as credit support for PPA requirements, and $19 million remains unused. The Company's subsidiaries are not parties to this letter of credit facility.

In addition, at both December 31, 2017 and 2016, the Company had $113 million of cash collateral posted related to PPA requirements.

### *Subsidiary Project Credit Facilities*

In connection with the construction of solar facilities by RE Tranquillity LLC, RE Garland Holdings LLC, and RE Roserock LLC, indirect subsidiaries of the Company, each subsidiary had entered into separate credit agreements (Project Credit Facilities), which were non-recourse to the Company (other than the subsidiary party to the agreement). Each Project Credit Facility provided (a) a senior secured construction loan credit facility, (b) a senior secured bridge loan facility, and (c) a senior secured letter of credit facility that was secured by the membership interests of the respective project company, with proceeds directed to finance project costs related to the respective solar facilities. Each Project Credit Facility was secured by the assets of the applicable project subsidiary and membership interests of the applicable project subsidiary. The Tranquillity, Garland, and Roserock Project Credit Facilities were fully repaid on October 14, 2016, December 29, 2016, and January 31, 2017, respectively.

Furthermore, in connection with the acquisition of the Henrietta solar facility on July 1, 2016, a subsidiary of the Company assumed a $217 million construction loan, which was fully repaid in September 2016.

## Financing Activities

### *Senior Notes*

In November 2017, the Company issued $525 million aggregate principal amount of Series 2017A Floating Rate Senior Notes due December 20, 2020, which bear interest based on three-month LIBOR. The net proceeds were used to redeem all of the $500 million aggregate principal amount of Series 2015D 1.85% Senior Notes due December 1, 2017 and to repay a portion of the Company's outstanding short-term debt.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

***Other Debt***

In September 2017, the Company amended its $60 million aggregate principal amount floating rate term loan to, among other things, increase the aggregate principal amount to $100 million and extend the maturity date from September 2017 to October 2018. The additional $40 million of proceeds were used to repay existing indebtedness and for other general corporate purposes. At December 31, 2017 , this outstanding term loan was included in securities due within one year.

In addition, during 2017 , the Company issued a total of $21 million in letters of credit under the Company's credit facilities.

### Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB and/or Baa2 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, energy price risk management, and transmission.

The maximum potential collateral requirements under these contracts at December 31, 2017 were as follows:

| Credit Ratings | Maximum Potential Collateral Requirements |
|---|---|
| | *(in millions)* |
| At BBB and/or Baa2 | $ 39 |
| At BBB- and/or Baa3 | $ 415 |
| At BB+ and/or Ba1 (*) | $ 1,118 |

(*) Any additional credit rating downgrades at or below BB- and/or Ba3 could increase collateral requirements up to an additional $38 million .

Included in these amounts are certain agreements that could require collateral in the event that Alabama Power or Georgia Power has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact the ability of the Company to access capital markets and would be likely to impact the cost at which it does so.

In addition, the Company has a PPA that could require collateral, but not accelerated payment, in the event of a downgrade of the Company's credit. The PPA requires credit assurances without stating a specific credit rating. The amount of collateral required would depend upon actual losses resulting from a credit downgrade.

On March 24, 2017, S&P revised its consolidated credit rating outlook for Southern Company and its subsidiaries (including the Company) from stable to negative.

While it is unclear how the credit rating agencies may respond to the Tax Reform Legislation, certain financial metrics, such as the funds from operations to debt percentage, used by the credit rating agencies to assess Southern Company and its subsidiaries, including the Company, may be negatively impacted. Absent actions by the Company to mitigate the resulting impacts, which, among other alternatives, could include adjusting the Company's capital structure, the Company's credit ratings could be negatively affected.

### Market Price Risk

The Company is exposed to market risks, primarily commodity price risk, interest rate risk, and occasionally foreign currency exchange rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the consolidated balance sheets as either assets or liabilities and are presented on a gross basis. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

At December 31, 2017 , the Company had $945 million of long-term variable rate notes outstanding. If the Company sustained a 100 basis point change in interest rates for its variable interest rate exposure, the change would effect annualized interest expense by approximately $9 million at December 31, 2017. Since a significant portion of outstanding indebtedness bears interest at fixed rates, the Company is not aware of any facts or circumstances that would significantly affect exposure on existing indebtedness in the near term. However, the impact on future financing costs cannot be determined at this time.

The Company had foreign currency denominated debt of €1.1 billion at December 31, 2017. The Company has mitigated its exposure to foreign currency exchange rate risk through the use of foreign currency swaps converting all interest and principal payments to fixed-rate U.S. dollars.

Because energy from the Company's facilities is primarily sold under long-term PPAs with tolling agreements and provisions shifting substantially all of the responsibility for fuel cost to the counterparties, the Company's exposure to market volatility in commodity fuel prices and prices of electricity is generally limited. However, the Company has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of uncontracted generating capacity.

For the years ended December 31, 2017 and 2016, the changes in fair value of energy-related derivative contracts associated with both power and natural gas positions were as follows:

| | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| Contracts outstanding at the beginning of period, assets (liabilities), net | **$ 16** | $ 1 |
| Contracts realized or settled | **(17)** | (3) |
| Current period changes (*) | **(9)** | 18 |
| Contracts outstanding at the end of period, assets (liabilities), net | **$ (10)** | $ 16 |

(*) Current period changes also include changes in the fair value of new contracts entered into during the period, if any.

For the years ending December 31, 2017 and 2016, the changes in contracts outstanding were attributable to both the volume and the prices of power and natural gas as follows:

| | **2017** | 2016 |
|---|---|---|
| **Power – net sold** | | |
| MWH (in millions) | **3.0** | 6.1 |
| Weighted average contract cost per MWH above (below) market prices (in dollars) | **$ (2.67)** | $ 1.45 |
| **Natural Gas – net purchased** | | |
| Commodity - mmBtu (in millions) | **14.4** | 27.1 |
| Commodity - weighted average contract cost per mmBtu above (below) market prices (in dollars) | **$ 0.12** | $ (0.27) |

Gains and losses on energy-related derivatives designated as cash flow hedges which are used by the Company to hedge anticipated purchases and sales are initially deferred in OCI before being recognized in income in the same period as the hedged transactions are reflected in earnings. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the consolidated statements of income as incurred.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2 of the fair value hierarchy. See Note 8 to the financial statements for further discussion of fair value measurements. The energy-related derivative contracts outstanding at December 31, 2017 all mature in 2018.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by S&P and Moody's or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance. See Note 1 to the financial statements under "Financial Instruments" and Note 9 to the financial statements for additional information.

### Capital Requirements and Contractual Obligations

The capital program of the Company is subject to periodic review and revision and is currently estimated to total $7.2 billion over the next five years through 2022. This includes approximately $0.9 billion in committed construction, capital improvements, and work to be performed under LTSAs, totaling approximately $400 million for 2018 and an average of approximately $137 million each year from 2019 through 2022. In addition, the capital program includes a further $6.3 billion in planned expenditures for plant acquisitions and placeholder growth, which averages approximately $1.3 billion per year. Planned expenditures for plant acquisitions and placeholder growth may vary materially due to market opportunities and the Company's ability to execute its growth strategy. Actual construction costs may vary from these estimates because of numerous factors such as: changes in business conditions; changes in the expected environmental compliance program; changes in environmental laws and regulations; the outcome of any legal challenges to the environmental rules; changes in FERC rules and regulations; changes in load projections; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. See Note 11 to the financial statements for additional information.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, leases, derivative obligations, other purchase commitments, and pension and other postretirement benefit plans are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 9 to the financial statements for additional information.

**Contractual Obligations**

Contractual obligations at December 31, 2017 were as follows:

| | 2018 | 2019-2020 | 2021-2022 | After 2022 | Total |
|---|---|---|---|---|---|
| | | | *(in millions)* | | |
| Long-term debt [(a)] — | | | | | |
| Principal | $ 770 | $ 1,425 | $ 977 | $ 2,630 | $ 5,802 |
| Interest | 189 | 334 | 278 | 1,524 | 2,325 |
| Financial derivative obligations [(b)] | 13 | — | — | — | 13 |
| Operating leases [(c)] | 22 | 45 | 45 | 815 | 927 |
| Purchase commitments — | | | | | |
| Capital [(d)] | 1,099 | 3,661 | 1,750 | — | 6,510 |
| Fuel [(e)] | 453 | 555 | 327 | 56 | 1,391 |
| Purchased power [(f)] | 40 | 82 | 42 | — | 164 |
| Other [(g)] | 149 | 315 | 216 | 1,770 | 2,450 |
| Pension and other postretirement benefit plans [(h)] | — | 1 | — | — | 1 |
| Total | $ 2,735 | $ 6,418 | $ 3,635 | $ 6,795 | $ 19,583 |

(a) All amounts are reflected based on final maturity dates and include the effects of interest rate derivatives employed to manage interest rate risk and effects of foreign currency swaps employed to manage foreign currency exchange rate risk. Included in debt principal is a $77 million gain related to the foreign currency hedge of €1.1 billion. The Company plans to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.
(b) For additional information, see Notes 1 and 9 to the financial statements.
(c) Operating lease commitments include certain land leases for solar and wind facilities that are subject to annual price escalation based on indices. See Note 7 to the financial statements under "Commitments" for additional information.
(d) The Company provides estimated capital expenditures for a five-year period, including capital expenditures associated with environmental regulations. Included in these amounts are planned expenditures for plant acquisitions and placeholder growth, which averages approximately $1.3 billion per year, and may vary materially each year due to market opportunities and the Company's ability to execute its growth strategy. Amounts represent current estimates of total expenditures, excluding capital expenditures covered under LTSAs which are reflected in "Other." See Note (g) below. At December 31, 2017, significant purchase commitments were outstanding in connection with the construction program.
(e) Primarily includes commitments to purchase, transport, and store natural gas. Amounts reflected are based on contracted cost and may contain provisions for price escalation. Amounts reflected for natural gas purchase commitments are based on various indices at the time of delivery and have been estimated based on the New York Mercantile Exchange future prices at December 31, 2017 .
(f) Purchased power commitments will be resold under a third party agreement at cost.
(g) Includes commitments related to LTSAs, operation and maintenance agreements, and transmission. LTSAs include price escalation based on inflation indices. Transmission commitments are based on the Southern Company system's current tariff rate for point-to-point transmission.
(h) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

**Cautionary Statement Regarding Forward-Looking Statements**

The Company's 2017 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning the strategic goals for the Company's business, economic conditions, fuel and environmental cost recovery , current and proposed environmental regulations and related compliance plans and estimated expenditures, pending or potential litigation matters, access to sources of capital, financing activities, estimated sales and purchases under power sale and purchase agreements, timing of expected future capacity need in existing markets, completion dates of construction projects, projections for the qualified pension plan and postretirement benefit plans contributions, filings with federal regulatory authorities, impacts of the Tax Reform Legislation, federal and state income tax benefits, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including environmental laws and regulations governing air, water, land, and protection of other natural resources , and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- the uncertainty surrounding the recently enacted Tax Reform Legislation, including implementing regulations and IRS interpretations, actions that may be taken in response by regulatory authorities, and its impact, if any, on the credit ratings of the Company;
- current and future litigation or regulatory investigations, proceedings, or inquiries ;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- transmission constraints;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of generating facilities, to construct facilities in accordance with the requirements of permits and licenses , and to satisfy any environmental performance standards , including the requirements of tax credits and other incentives ;
- investment performance of the Company's employee and retiree benefit plans ;
- advances in technology;
- ongoing renewable energy partnerships and development agreements;
- state and federal rate regulations ;
- the ability to successfully operate generating facilities and the successful performance of necessary corporate functions;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, including the potential sale of a 33% equity interest in substantially all of the Company's solar assets, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or physical attack and the threat of physical attacks;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on foreign currency exchange rates, counterparty performance, and the economy in general ;

- the ability of the Company to obtain additional generating capacity (or sell excess generating capacity) at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports filed by the Company from time to time with the SEC.

**The Company expressly disclaims any obligation to update any forward-looking statements.**

**CONSOLIDATED STATEMENTS OF INCOME**
**For the Years Ended December 31, 2017 , 2016 , and 2015**
**Southern Power Company and Subsidiary Companies 2017 Annual Report**

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| **Operating Revenues:** | | | |
| Wholesale revenues, non-affiliates | **$ 1,671** | $ 1,146 | $ 964 |
| Wholesale revenues, affiliates | **392** | 419 | 417 |
| Other revenues | **12** | 12 | 9 |
| Total operating revenues | **2,075** | 1,577 | 1,390 |
| **Operating Expenses:** | | | |
| Fuel | **621** | 456 | 441 |
| Purchased power | **149** | 102 | 93 |
| Other operations and maintenance | **386** | 354 | 260 |
| Depreciation and amortization | **503** | 352 | 248 |
| Taxes other than income taxes | **48** | 23 | 22 |
| Total operating expenses | **1,707** | 1,287 | 1,064 |
| **Operating Income** | **368** | 290 | 326 |
| **Other Income and (Expense):** | | | |
| Interest expense, net of amounts capitalized | **(191)** | (117) | (77) |
| Other income (expense), net | **1** | 6 | 1 |
| Total other income and (expense) | **(190)** | (111) | (76) |
| **Earnings Before Income Taxes** | **178** | 179 | 250 |
| Income taxes (benefit) | **(939)** | (195) | 21 |
| **Net Income** | **1,117** | 374 | 229 |
| Less: Net income attributable to noncontrolling interests | **46** | 36 | 14 |
| **Net Income Attributable to the Company** | **$ 1,071** | $ 338 | $ 215 |

The accompanying notes are an integral part of these consolidated financial statements.

**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**
**For the Years Ended December 31, 2017 , 2016 , and 2015**
**Southern Power Company and Subsidiary Companies 2017 Annual Report**

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| **Net Income** | **$ 1,117** | $ 374 | $ 229 |
| Other comprehensive income (loss): | | | |
| Qualifying hedges: | | | |
| Changes in fair value, net of tax of $39, $(17), and $-, respectively | **63** | (27) | — |
| Reclassification adjustment for amounts included in net income, net of tax of $(46), $36, and $-, respectively | **(73)** | 58 | 1 |
| Total other comprehensive income (loss) | **(10)** | 31 | 1 |
| Less: Comprehensive income attributable to noncontrolling interests | **46** | 36 | 14 |
| **Comprehensive Income Attributable to the Company** | **$ 1,061** | $ 369 | $ 216 |

The accompanying notes are an integral part of these consolidated financial statements.

**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**For the Years Ended December 31, 2017 , 2016 , and 2015**
**Southern Power Company and Subsidiary Companies 2017 Annual Report**

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | *(in millions)* | | |
| **Operating Activities:** | | | |
| Net income | **$ 1,117** | $ 374 | $ 229 |
| Adjustments to reconcile net income to net cash provided from operating activities — | | | |
| Depreciation and amortization, total | **536** | 370 | 254 |
| Deferred income taxes | **(263)** | (1,063) | 42 |
| Investment tax credits | **—** | — | 162 |
| Amortization of investment tax credits | **(57)** | (37) | (19) |
| Collateral deposits | **(4)** | (102) | — |
| Accrued income taxes, non-current | **14** | (109) | 109 |
| Income taxes receivable, non-current | **(61)** | (13) | — |
| Other, net | **(9)** | 12 | (2) |
| Changes in certain current assets and liabilities — | | | |
| -Receivables | **(60)** | (54) | 18 |
| -Other current assets | **(4)** | (25) | (30) |
| -Accrued taxes | **(55)** | 940 | 269 |
| -Other current liabilities | **1** | 46 | (29) |
| Net cash provided from operating activities | **1,155** | 339 | 1,003 |
| **Investing Activities:** | | | |
| Business acquisitions | **(1,032)** | (2,294) | (1,719) |
| Property additions | **(268)** | (2,114) | (1,005) |
| Change in construction payables | **(153)** | (57) | 251 |
| Investment in restricted cash | **(16)** | (733) | (159) |
| Distribution of restricted cash | **34** | 736 | 154 |
| Payments pursuant to LTSAs and for equipment not yet received | **(203)** | (350) | (82) |
| Other investing activities | **15** | 15 | 22 |
| Net cash used for investing activities | **(1,623)** | (4,797) | (2,538) |
| **Financing Activities:** | | | |
| Increase (decrease) in notes payable, net | **(104)** | 73 | (58) |
| Proceeds — | | | |
| Capital contributions | **—** | 1,850 | 646 |
| Senior notes | **525** | 2,831 | 1,650 |
| Other long-term debt | **43** | 65 | 402 |
| Redemptions — | | | |
| Senior notes | **(500)** | (200) | (525) |
| Other long-term debt | **(18)** | (86) | (4) |
| Distributions to noncontrolling interests | **(119)** | (57) | (18) |
| Capital contributions from noncontrolling interests | **80** | 682 | 341 |
| Purchase of membership interests from noncontrolling interests | **(59)** | (129) | — |
| Payment of common stock dividends | **(317)** | (272) | (131) |
| Other financing activities | **(33)** | (30) | (13) |
| Net cash provided from (used for) financing activities | **(502)** | 4,727 | 2,290 |
| **Net Change in Cash and Cash Equivalents** | **(970)** | 269 | 755 |
| **Cash and Cash Equivalents at Beginning of Year** | **1,099** | 830 | 75 |
| **Cash and Cash Equivalents at End of Year** | **$ 129** | $ 1,099 | $ 830 |
| **Supplemental Cash Flow Information:** | | | |
| Cash paid (received) during the period for — | | | |
| Interest (net of $11, $44, and $14 capitalized, respectively) | **$ 189** | $ 89 | $ 74 |
| Income taxes (net of refunds and investment tax credits) | **(487)** | 116 | (518) |

| | | | |
|---|---|---|---|
| Noncash transactions — | | | |
| Accrued property additions at year-end | **32** | 251 | 257 |
| Accrued acquisitions at year-end | **—** | 461 | — |

The accompanying notes are an integral part of these consolidated financial statements.

**CONSOLIDATED BALANCE SHEETS**
**At December 31, 2017 and 2016**
**Southern Power Company and Subsidiary Companies 2017 Annual Report**

| **Assets** | | **2017** | | 2016 |
|---|---|---|---|---|
| | | *(in millions)* | | |
| **Current Assets:** | | | | |
| Cash and cash equivalents | **$** | **129** | $ | 1,099 |
| Receivables — | | | | |
| Customer accounts receivable | | **117** | | 102 |
| Affiliated | | **50** | | 57 |
| Other | | **98** | | 34 |
| Materials and supplies | | **278** | | 337 |
| Prepaid income taxes | | **50** | | 74 |
| Other current assets | | **36** | | 54 |
| Total current assets | | **758** | | 1,757 |
| **Property, Plant, and Equipment:** | | | | |
| In service | | **13,755** | | 12,728 |
| Less: Accumulated provision for depreciation | | **1,910** | | 1,484 |
| Plant in service, net of depreciation | | **11,845** | | 11,244 |
| Construction work in progress | | **511** | | 398 |
| Total property, plant, and equipment | | **12,356** | | 11,642 |
| **Other Property and Investments:** | | | | |
| Intangible assets, net of amortization of $47 and $22 at December 31, 2017 and December 31, 2016, respectively | | **411** | | 436 |
| Total other property and investments | | **411** | | 436 |
| **Deferred Charges and Other Assets:** | | | | |
| Prepaid LTSAs | | **118** | | 101 |
| Accumulated deferred income taxes | | **925** | | 594 |
| Income taxes receivable, non-current | | **72** | | 11 |
| Other deferred charges and assets | | **566** | | 628 |
| Total deferred charges and other assets | | **1,681** | | 1,334 |
| **Total Assets** | **$** | **15,206** | $ | 15,169 |

The accompanying notes are an integral part of these consolidated financial statements.

**CONSOLIDATED BALANCE SHEETS**
**At December 31, 2017 and 2016**
**Southern Power Company and Subsidiary Companies 2017 Annual Report**

| **Liabilities and Stockholders' Equity** | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Current Liabilities:** | | |
| Securities due within one year | **$ 770** | $ 560 |
| Notes payable | **105** | 209 |
| Accounts payable — | | |
| Affiliated | **102** | 88 |
| Other | **103** | 278 |
| Accrued taxes — | | |
| Accrued income taxes | **—** | 148 |
| Other accrued taxes | **4** | 7 |
| Acquisitions payable | **5** | 461 |
| Other current liabilities | **143** | 152 |
| Total current liabilities | **1,232** | 1,903 |
| **Long-Term Debt:** | | |
| Senior notes — | | |
| 1.50% due 2018 | **—** | 350 |
| 1.95% due 2019 | **600** | 600 |
| 2.375% due 2020 | **300** | 300 |
| 2.50% due 2021 | **300** | 300 |
| 1.00% due 2022 | **720** | 632 |
| 1.85% to 5.25% due 2023-2046 | **2,664** | 2,592 |
| Other long-term debt — | | |
| Variable rate (1.88% at 12/31/17) due 2018 | **—** | 320 |
| Variable rate (2.18% at 12/31/17) due 2020 | **525** | — |
| Variable rate (3.75% at 1/1/17) due 2032-2036 | **—** | 15 |
| Unamortized debt premium (discount), net | **(10)** | (12) |
| Unamortized debt issuance expense | **(28)** | (29) |
| Long-term debt | **5,071** | 5,068 |
| **Deferred Credits and Other Liabilities:** | | |
| Accumulated deferred income taxes | **199** | 152 |
| Accumulated deferred ITCs | **1,884** | 1,839 |
| Other deferred credits and liabilities | **322** | 368 |
| Total deferred credits and other liabilities | **2,405** | 2,359 |
| **Total Liabilities** | **8,708** | 9,330 |
| **Redeemable Noncontrolling Interests** | **—** | 164 |
| **Common Stockholder's Equity:** | | |
| Common stock, par value $0.01 per share — | | |
| Authorized — 1,000,000 shares | | |
| Outstanding — 1,000 shares | **—** | — |
| Paid-in capital | **3,662** | 3,671 |
| Retained earnings | **1,478** | 724 |
| Accumulated other comprehensive income | **(2)** | 35 |
| Total common stockholder's equity | **5,138** | 4,430 |
| **Noncontrolling Interests** | **1,360** | 1,245 |
| **Total Stockholders' Equity** | **6,498** | 5,675 |
| **Total Liabilities and Stockholders' Equity** | **$ 15,206** | $ 15,169 |
| **Commitments and Contingent Matters** (See notes) | | |

The accompanying notes are an integral part of these consolidated financial statements.

**CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY**
**For the Years Ended December 31, 2017 , 2016 , and 2015**
**Southern Power Company and Subsidiary Companies 2017 Annual Report**

| | Number of Common Shares Issued | Common Stock | Paid-In Capital | Retained Earnings | Accumulated Other Comprehensive Income | Total Common Stockholder's Equity | Noncontrolling Interests [(a)] | Total |
|---|---|---|---|---|---|---|---|---|
| | | | | | *(in millions)* | | | |
| **Balance at December 31, 2014** | — | $ — | $ 1,176 | $ 573 | $ 3 | $ 1,752 | $ 219 | $ 1,971 |
| Net income attributable to Southern Power | — | — | — | 215 | — | 215 | — | 215 |
| Capital contributions from parent company | — | — | 646 | — | — | 646 | — | 646 |
| Other comprehensive income | — | — | — | — | 1 | 1 | — | 1 |
| Cash dividends on common stock | — | — | — | (131) | — | (131) | — | (131) |
| Capital contributions from noncontrolling interests | — | — | — | — | — | — | 567 | 567 |
| Distributions to noncontrolling interests | — | — | — | — | — | — | (17) | (17) |
| Net loss attributable to noncontrolling interests | — | — | — | — | — | — | 12 | 12 |
| **Balance at December 31, 2015** | — | — | 1,822 | 657 | 4 | 2,483 | 781 | 3,264 |
| Net income attributable to Southern Power | — | — | — | 338 | — | 338 | — | 338 |
| Capital contributions from parent company | — | — | 1,850 | — | — | 1,850 | — | 1,850 |
| Other comprehensive income | — | — | — | — | 31 | 31 | — | 31 |
| Cash dividends on common stock | — | — | — | (272) | — | (272) | — | (272) |
| Capital contributions from noncontrolling interests | — | — | — | — | — | — | 618 | 618 |
| Distributions to noncontrolling interests | — | — | — | — | — | — | (57) | (57) |
| Purchase of membership interests from noncontrolling interests | — | — | — | — | — | — | (129) | (129) |
| Net income attributable to noncontrolling interests | — | — | — | — | — | — | 32 | 32 |
| Other | — | — | (1) | 1 | — | — | — | — |
| **Balance at December 31, 2016** | **—** | **—** | **3,671** | **724** | **35** | **4,430** | **1,245** | **5,675** |
| Net income attributable to Southern Power | **—** | **—** | **—** | **1,071** | **—** | **1,071** | **—** | **1,071** |
| Capital contributions from parent company | **—** | **—** | **(2)** | **—** | **—** | **(2)** | **—** | **(2)** |
| Other comprehensive income | **—** | **—** | **—** | **—** | **(10)** | **(10)** | **—** | **(10)** |
| Cash dividends on common stock | **—** | **—** | **—** | **(317)** | **—** | **(317)** | **—** | **(317)** |
| Other comprehensive income transfer from SCS [(b)] | **—** | **—** | **—** | **—** | **(27)** | **(27)** | **—** | **(27)** |
| Capital contributions from noncontrolling interests | **—** | **—** | **—** | **—** | **—** | **—** | **79** | **79** |
| Distributions to noncontrolling interests | **—** | **—** | **—** | **—** | **—** | **—** | **(122)** | **(122)** |
| Net income attributable to noncontrolling interests | **—** | **—** | **—** | **—** | **—** | **—** | **44** | **44** |
| Reclassification from redeemable noncontrolling interests | **—** | **—** | **—** | **—** | **—** | **—** | **114** | **114** |
| Other | **—** | **—** | **(7)** | **—** | **—** | **(7)** | **—** | **(7)** |
| **Balance at December 31, 2017** | **—** | **$ —** | **$ 3,662** | **$ 1,478** | **$ (2)** | **$ 5,138** | **$ 1,360** | **$ 6,498** |

(a) Excludes redeemable noncontrolling interests. See Note 10 to the financial statements under "Noncontrolling Interests" for additional information.
(b) In connection with the Company becoming a participant to the Southern Company qualified pension plan and other postretirement benefit plan, $27 million of other comprehensive income, net of tax of $9 million, was transferred from SCS.

The accompanying notes are an integral part of these consolidated financial statements.

**NOTES TO FINANCIAL STATEMENTS**
**Southern Power Company and Subsidiary Companies 2017 Annual Report**

## Index to the Notes to Financial Statements

## 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

### General

Southern Power Company is a wholly-owned subsidiary of Southern Company, which is also the parent company of four traditional electric operating companies, Southern Company Gas (as of July 1, 2016), SCS, and other direct and indirect subsidiaries. The traditional electric operating companies – Alabama Power, Georgia Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. Southern Power Company and its subsidiaries (the Company) develop, construct, acquire, own, and manage power generation assets, including renewable energy projects, and sell electricity at market-based rates in the wholesale market. Southern Company Gas distributes natural gas through utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies.

Effective in December 2017, 538 employees transferred from SCS to the Company. The Company became obligated for related employee costs including pension, other postretirement benefits, and stock-based compensation and has recognized the respective balance sheet assets and liabilities, including AOCI impacts, in its balance sheet at December 31, 2017. Prior to the transfer of employees, the Company's agreements with SCS provided for employee services rendered at amounts in compliance with FERC regulations. The Company adopted the same compensation and benefits plans that SCS has and, therefore, future expenses are not expected to be materially different on a per employee basis.

The preparation of consolidated financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the consolidated financial statements have been reclassified to conform to the current year presentation.

The consolidated financial statements include the accounts of Southern Power Company and its wholly-owned and majority-owned subsidiaries. Intercompany accounts and transactions have been eliminated in consolidation.

### Recently Issued Accounting Standards

#### *Revenue*

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers* (ASC 606), replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the new standard is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

The Company has completed the evaluation of all revenue streams and determined that the adoption of ASC 606 will not change the current timing or amounts of revenue recognized in the Company's financial statements. Some contractual arrangements, such as certain capacity and energy payments, are excluded from the scope of ASC 606 and included in the scope of the current leasing guidance or the current derivative guidance.

The new standard is effective for reporting periods beginning after December 15, 2017. The Company applied the modified retrospective method of adoption effective January 1, 2018. The Company also utilized practical expedients which allowed it to apply the standard to open contracts at the date of adoption and to reflect the aggregate effect of all modifications when identifying performance obligations and allocating the transaction price for contracts modified before the effective date. The adoption of ASC 606 did not result in a cumulative adjustment.

#### *Leases*

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged . ASU 2016-02 is effective for fiscal years beginning after December 15, 2018 and the Company will adopt the new standard effective January 1, 2019.

The Company is currently implementing an information technology system along with the related changes to internal controls and accounting policies that will support the accounting for leases under ASU 2016-02. In addition, the Company has substantially completed a detailed inventory and analysis of its leases where the majority relate to land leases for its renewable generation facilities. While the Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet for lessee arrangements.

***Other***

In November 2016, the FASB issued ASU No. 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash* (ASU 2016-18). ASU 2016-18 eliminates the need to reflect transfers between cash and restricted cash in operating, investing, and financing activities in the statement of cash flows. Upon adoption, the net change in cash and cash equivalents during the period will include amounts generally described as restricted cash or restricted cash equivalents. ASU 2016-18 is effective for fiscal years beginning after December 15, 2017, and will be applied retrospectively to each period presented. The Company adopted ASU 2016-18 effective January 1, 2018 with no material impact on its financial statements.

On March 10, 2017, the FASB issued ASU No. 2017-07, *Compensation - Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017-07). ASU 2017-07 requires that an employer report the service cost component in the same line item or items as other compensation costs and requires the other components of net periodic pension and postretirement benefit costs to be separately presented in other income (expense) in the income statement. Additionally, only the service cost component related to construction labor is eligible for capitalization, when applicable. The Company adopted ASU 2017-07 which is effective for periods beginning after December 15, 2017; however, since the Company became a sponsor of a qualified pension plan and postretirement benefit plan in December 2017, no retrospective presentation of net periodic benefits costs for 2016 or 2017 is required. See Note 2 for additional information.

On August 28, 2017, the FASB issued ASU No. 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities* (ASU 2017-12), amending the hedge accounting recognition and presentation requirements. ASU 2017-12 makes more financial and non-financial hedging strategies eligible for hedge accounting, amends the related presentation and disclosure requirements, and simplifies hedge effectiveness assessment requirements. ASU 2017-12 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

**Affiliate Transactions**

Total revenues from all PPAs with affiliates, included in wholesale revenue affiliates on the consolidated statements of income, were $233 million , $258 million , and $219 million for the years ended December 31, 2017 , 2016 , and 2015 , respectively. Included within these revenues were affiliate PPAs accounted for as operating leases, which totaled $81 million for the year ended December 31, 2017 and $109 million for each of the years ended December 31, 2016 and 2015 .

The Company has an agreement with SCS under which the following services are rendered to the Company at amounts in compliance with FERC regulation: general and design engineering, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, labor, and other services with respect to business and operations, construction management, and transactions associated with the Southern Company system's fleet of generating units. Prior to December 2017, the Company did not have employees and thus all employee-related charges were rendered at amounts in compliance with FERC regulation under agreements with SCS. Costs for all of these services from SCS totaled $218 million , $193 million , and $146 million for the years ended December 31, 2017 , 2016 , and 2015 , respectively. Of these costs, $192 million , $173 million , and $138 million for the years ended December 31, 2017 , 2016 , and 2015 , respectively, were charged to other operations and maintenance expenses; the remainder was primarily capitalized to property, plant, and equipment. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

Total power purchased from affiliates through the power pool, included in purchased power in the consolidated statements of income, totaled $27 million for the year ended December 31, 2017 and $21 million for each of the years ended December 31, 2016 and 2015.

The Company also has several agreements with SCS for transmission services. Transmission services purchased from SCS totaled $13 million for the year ended December 31, 2017 and $11 million for each of the years ended December 31, 2016 and 2015 and were charged to other operations and maintenance in the consolidated statements of income. All charges were billed to the Company based on the Southern Company Open Access Transmission Tariff as filed with the FERC.

Prior to Southern Company's acquisition of Southern Company Gas, SCS, as agent for the Company, had agreements with various subsidiaries of Southern Company Gas to purchase natural gas. Natural gas purchases made by the Company from Southern Company Gas' subsidiaries were $119 million for the year ended December 31, 2017 and $17 million for the period subsequent to

Southern Company's acquisition of Southern Company Gas through December 31, 2016, and are included in fuel expense on the consolidated statements of income.

On September 1, 2016, Southern Company Gas acquired a 50% equity interest in Southern Natural Gas Company, L.L.C. (SNG). Prior to completion of the acquisition, SCS, as agent for the Company, had entered into a long-term interstate natural gas transportation agreement with SNG. The interstate transportation service provided to the Company by SNG pursuant to this agreement is governed by the terms and conditions of SNG's natural gas tariff and is subject to FERC regulation. Transportation costs under this agreement were $25 million for the year ended December 31, 2017 and $7 million for the period subsequent to Southern Company Gas' investment in SNG through December 31, 2016.

The Company and the traditional electric operating companies may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See "Revenues" herein for additional information. The Company and the traditional electric operating companies generally settle amounts related to the above transactions on a monthly basis in the month following the performance of such services or the purchase or sale of electricity.

**Acquisition Accounting**

The Company may acquire generation assets as part of its overall growth strategy. At the time of an acquisition, the Company will assess if these assets and activities meet the definition of a business. For acquisitions that meet the definition of a business, the Company includes operating results from the date of acquisition in its consolidated financial statements. The purchase price, including any contingent consideration, is allocated based on the fair value of the identifiable assets acquired and liabilities assumed (including any intangible assets). Assets acquired that do not meet the definition of a business are accounted for as an asset acquisition.

The purchase price of each asset acquisition is allocated based on the relative fair value of assets acquired. Determining the fair value of assets acquired and liabilities assumed requires management judgment and the Company may engage independent valuation experts to assist in this process. Fair values are determined by using market participant assumptions, and typically include the timing and amounts of future cash flows, incurred construction costs, the nature of acquired contracts, discount rates, power market prices, and expected asset lives. Any due diligence or transition costs incurred by the Company for potential or successful acquisitions are expensed as incurred.

Contingent consideration primarily relates to fixed amounts due to the seller once the facility is placed in service. For contingent consideration with variable payments, the Company fair values the arrangement with any changes recorded in the consolidated statements of income. See Note 8 for additional fair value information.

**Revenues**

The Company sells capacity at rates specified under contractual terms for long-term PPAs. These PPAs are generally accounted for as operating leases, non-derivatives, or normal sale derivatives. Capacity revenues from PPAs classified as operating leases are recognized on a straight-line basis over the term of the agreement. Capacity revenues from PPAs classified as non-derivatives or normal sales are recognized at the lesser of the levelized amount or the amount billable under the contract over the respective contract periods. When multiple contracts exist with the same counterparty, the revenues from each contract are accounted for as separate arrangements. All capacity revenues are included in wholesale revenues.

The Company may also enter into contracts to sell short-term capacity in the wholesale electricity markets. These sales are generally classified as mark-to-market derivatives and net unrealized gains (losses) on such contracts are recorded in wholesale revenues. See Note 9 for additional information.

Energy revenues and other contingent revenues are recognized in the period the energy is delivered or the service is rendered. Transmission revenues and other fees are recognized as earned as other operating revenues. See "Financial Instruments" herein for additional information.

**NOTES (continued)**
**Southern Power Company and Subsidiary Companies 2017 Annual Report**

Significant portions of the Company's revenues have been derived from certain customers pursuant to PPAs. The following table shows the percentage of total revenues for the Company's top three customers for each of the years presented:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| Georgia Power | **11.3%** | 16.5% | 15.8% |
| Duke Energy Corporation | **6.7%** | 7.8% | 8.2% |
| Morgan Stanley Capital Group | **4.5%** | N/A | N/A |
| San Diego Gas & Electric Company | **N/A** | 5.7% | N/A |
| Florida Power & Light Company | **N/A** | N/A | 10.7% |

**Fuel Costs**

Fuel costs are expensed as the fuel is used. Fuel costs also include emissions allowances which are expensed as the emissions occur.

**Development Costs**

The Company capitalizes development costs once a project is probable of completion, primarily based on a review of its economics and operational feasibility, as well as status of power off-take agreements and regulatory approvals, if applicable. Capitalized development costs are included in construction work in progress on the consolidated balance sheets. All development costs incurred prior to the determination that a project is probable of completion are expensed as incurred and included in other operations and maintenance expense in the consolidated statements of income. If it is determined that a project is no longer probable of completion, any capitalized development costs are expensed and included in other operations and maintenance expense in the consolidated statements of income.

**Income and Other Taxes**

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences.

Under current tax regulation, certain projects related to the construction of renewable facilities are eligible for federal ITCs. The Company estimates eligible costs which, as they relate to acquisitions, may not be finalized until the allocation of the purchase price to assets has been finalized. The Company applies the deferred method to ITCs as opposed to the flow-through method. Under the deferred method the ITCs are recorded as a deferred credit and amortized to income tax expense over the life of the respective asset. Furthermore, the tax basis of the asset is reduced by 50% of the ITCs received, resulting in a net deferred tax asset. The Company has elected to recognize the tax benefit of this basis difference as a reduction to income tax expense in the year in which the plant reaches commercial operation. In addition, certain projects are eligible for federal PTCs, which are recorded as an income tax benefit based on KWH production. Federal ITCs and PTCs available to reduce income taxes payable were not fully utilized during 2017 and will be carried forward and utilized in future years. The Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 for additional information.

**Property, Plant, and Equipment**

The Company's depreciable property, plant, and equipment consists primarily of generation assets.

Property, plant, and equipment is stated at original cost or acquired fair value. Original cost includes: materials, direct labor incurred by contractors and affiliated companies, and interest capitalized. Interest is capitalized on qualifying projects during the development and construction period. The cost to replace significant items of property defined as retirement units is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred.

When depreciable property, plant, and equipment is retired, or otherwise disposed of in the normal course of business, the applicable cost and accumulated depreciation is removed and a gain or loss is recognized in the consolidated statements of income.

**Depreciation**

The Company applies component depreciation, where depreciation is computed principally by the straight-line method over the estimated useful life of the asset. Certain generation assets related to natural gas-fired facilities are depreciated on a units-of-production basis, using hours or starts, to better match outage and maintenance costs to the usage of, and revenues from, these assets.

The primary assets in property, plant, and equipment are generating facilities, which generally have estimated useful lives as follows:

| Generating facility | Useful life |
|---|---|
| Natural gas | Up to 45 years |
| Biomass | Up to 40 years |
| Solar | Up to 35 years |
| Wind | Up to 30 years |

The Company reviews its estimated useful lives and salvage values on an ongoing basis. The results of these reviews could result in changes which could have a material impact on net income in the near term.

**Asset Retirement Obligations**

Asset retirement obligations (ARO) are computed as the present value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities. The ARO liability primarily relates to the Company's solar and wind facilities, which are located on long-term land leases requiring the restoration of land at the end of the lease. See Note 11 for acquisitions during 2017 and 2016 which contributed to the increased liability.

Details of the AROs included on the consolidated balance sheets are as follows:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| Balance at beginning of year | **$ 64** | $ 21 |
| Liabilities incurred | **6** | 42 |
| Accretion | **4** | 1 |
| Cash flow revisions | **4** | — |
| Balance at end of year | **$ 78** | $ 64 |

**Long-Term Service Agreements**

The Company has entered into LTSAs for the purpose of securing maintenance support for its natural gas-fired generating facilities. The LTSAs cover all planned inspections on the covered equipment, which generally includes the cost of all labor and materials. The LTSAs also obligate the counterparties to cover the costs of unplanned maintenance on the covered equipment subject to limits and scope specified in each contract.

Payments made under the LTSAs prior to the performance of any planned inspections or unplanned capital maintenance are recorded as a prepayment in other current assets and noncurrent assets on the consolidated balance sheets and are recorded as payments pursuant to LTSAs and for equipment not yet received in the statements of cash flows. At the time work is performed, which typically occurs during planned inspections, an appropriate amount is transferred from the prepayment to property, plant, and equipment or charged to expense. The receipt of major parts into materials and supplies inventory prior to planned inspections is treated as a noncash transaction for purposes of the consolidated statements of cash flows.

**Impairment of Long-Lived Assets and Intangibles**

The Company evaluates long-lived assets and finite-lived intangibles for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The Company's intangible assets consist primarily of certain PPAs acquired, which are amortized over the term of the PPAs, which have a weighted average term of 19 years . The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If the estimate of undiscounted future cash flows is less than the carrying value of the asset, the fair value of the asset is determined and a loss is recorded.

Amortization expense for acquired PPAs was $25 million , $10 million , and $3 million for the years ended December 31, 2017 , 2016 , and 2015 , respectively, and is recorded in operating revenues. The estimated annual amortization expense is $25 million for each of the next five years.

**Transmission Receivables/Prepayments**

As a result of the Company's growth from the acquisition and construction of generating facilities, the Company has transmission receivables and/or prepayments representing the portion of interconnection network and transmission upgrades that will be reimbursed to the Company. Upon completion of the related project, transmission costs are generally reimbursed by the interconnection provider within a five -year period and the receivable/prepayments are reduced as payments or services are received.

**Restricted Cash**

The Company has restricted cash primarily related to certain acquisitions and construction projects. The aggregate amount of restricted cash at December 31, 2017 and 2016 was $11 million and $13 million , respectively.

**Cash and Cash Equivalents**

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

**Materials and Supplies**

Materials and supplies include the average cost of generating plant materials and are recorded as inventory when purchased and then expensed or capitalized to property, plant, and equipment, as appropriate, at weighted average cost when installed. In addition, certain major parts are recorded as inventory when acquired and then capitalized at cost when installed to property, plant, and equipment.

**Fuel Inventory**

Fuel inventory, which is included in other current assets, includes the cost of oil, natural gas, biomass, and emissions allowances. The Company maintains oil inventory for use at several natural gas generating units. The Company has contracts in place for natural gas storage to support normal operations of the Company's natural gas generating units. The Company also maintains biomass inventory for use at Plant Nacogdoches. Inventory is maintained using the weighted average cost method. Fuel inventory and emissions allowances are recorded at actual cost when purchased and then expensed at weighted average cost as used. Emissions allowances granted by the EPA are included at zero cost.

**Financial Instruments**

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, electricity purchases and sales, and foreign currency exchange rates. All derivative financial instruments are recognized as either assets or liabilities on the consolidated balance sheets (included in "Other") and are measured at fair value. See Note 8 for additional information regarding fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions result in the deferral of related gains and losses in AOCI until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded in the financial statement line item where they will eventually settle. Cash flows from derivatives are classified on the statement of cash flows in the same category as the hedged item. See Note 9 for additional information regarding derivatives.

The Company offsets the fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2017 or 2016.

The Company is exposed to potential losses related to financial instruments in the event of counterparties' nonperformance. The Company has established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

**Comprehensive Income**

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, certain changes in pension and other postretirement benefit plans, and reclassifications of amounts included in net income.

Accumulated OCI (loss) balances, net of tax effects, were as follows:

| | Qualifying Hedges | Pension and Other Postretirement Benefit Plans | Accumulated Other Comprehensive Income (Loss) |
|---|---|---|---|
| | | *(in millions)* | |
| Balance at December 31, 2016 | $ 35 | $ — | $ 35 |
| Current period change | (10) | — | (10) |
| Other comprehensive income transfer from SCS (*) | — | (27) | (27) |
| Balance at December 31, 2017 | $ 25 | $ (27) | $ (2) |

(*) In connection with the Company becoming a participant to the Southern Company qualified pension plan and other postretirement benefit plan, $27 million of OCI, net of tax of $9 million , was transferred from SCS.

**Variable Interest Entities**

The primary beneficiary of a variable interest entity (VIE) is required to consolidate the VIE when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE.

The Company has certain wholly-owned subsidiaries that are determined to be VIEs. The Company is considered the primary beneficiary of these VIEs because it controls the most significant activities of the VIEs, including operating and maintaining the respective assets, and has the obligation to absorb expected losses of these VIEs to the extent of its equity interests.

## 2. RETIREMENT BENEFITS

Effective in December 2017, 538 employees transferred from SCS to the Company. Accordingly, the Company assumed various compensation and benefit plans including a defined benefit, trusteed, pension plan covering substantially all employees. The qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). With the transfer of employees, the Company assumed the related benefit obligations from SCS of $139 million for the qualified pension plan (along with trust assets of $138 million ) and $11 million for other postretirement benefit plans, together with $36 million in prior service costs and net gains/losses that are in OCI. In 2018, the Company will also begin providing certain defined benefits under a non-qualified pension plan for a select group of management and highly compensated employees. No obligation related to these benefits was assumed in the employee transfer; however, obligations under the non-qualified pension plan for future services rendered by employees will be recognized beginning in 2018 and ultimately funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans that are to be funded on a cash basis.

Prior to the transfer of employees in December 2017, substantially all expenses charged by SCS, including pension and other postretirement benefit costs, were recorded in other operations and maintenance expense. Beginning in 2018, in connection with the adoption of ASU 2017-07, the service cost component of pension and postretirement benefit costs will be recorded in other operations and maintenance expense while the non-service cost components of pension and postretirement benefit costs will be recorded in other income (expense). See Note 1 under "General" for additional information.

### Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine the benefit obligations for the pension and other postretirement plans as of the December 31, 2017 measurement date are presented below.

| **Assumptions used to determine benefit obligations:** | **2017** |
|---|---|
| **Pension plans** | |
| Discount rate | **3.94%** |
| Annual salary increase | **4.46** |
| **Other postretirement benefit plans** | |
| Discount rate | **3.81%** |
| Annual salary increase | **4.46** |

In determining the amount of pension cost to be recognized in 2018, the Company estimates the expected rate of return on pension plan assets using a financial model to project the expected return on the current investment portfolio. The analysis projects an expected rate of return on each of the different asset classes in order to arrive at the expected return on the entire portfolio relying on the trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), the trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of the trust's portfolio.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) is a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2017 were as follows:

| | **Initial Cost Trend Rate** | **Ultimate Cost Trend Rate** | **Year That Ultimate Rate is Reached** |
|---|---|---|---|
| Pre-65 | **6.50%** | **4.50%** | **2026** |
| Post-65 medical | **5.00** | **4.50** | **2026** |
| Post-65 prescription | **10.00** | **4.50** | **2026** |

An annual increase or decrease in the assumed medical care cost trend rate of 1% would have an immaterial effect on the APBO at December 31, 2017.

### Pension Plan

The total accumulated benefit obligation for the pension plan was $111 million at December 31, 2017 . The projected benefit obligation for the pension plan was $139 million and the fair value of plan assets was $138 million at December 31, 2017 .

Presented below are the amounts included in AOCI at December 31, 2017 related to the Company's pension plan that had not yet been recognized in net periodic pension cost, along with the estimated amortization of such amounts for 2018.

| | **2017** | **Estimated Amortization in 2018** |
|---|---|---|
| | *(in millions)* | |
| Prior service cost | **$ 1** | **$ —** |
| Net (gain) loss | **32** | **2** |
| AOCI | **$ 33** | |

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plan. At December 31, 2017 , estimated benefit payments average approximately $4 million each year for the next five years, and for the five-year period from 2023 to 2027 estimated benefit payments are $27 million .

**Other Postretirement Benefits**

The APBO for the other postretirement benefit plan at December 31, 2017 is $11 million . Amounts recognized in the balance sheet at December 31, 2017 related to the Company's other postretirement benefit plan consist of the following:

| | 2017 |
|---|---|
| | *(in millions)* |
| Employee benefit obligations (included in other deferred credits and liabilities) | $ (11) |
| AOCI | 3 |

Presented below are the amounts included in AOCI at December 31, 2017 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2018.

| | 2017 | Estimated Amortization in 2018 |
|---|---|---|
| | *(in millions)* | |
| Net (gain) loss | $ 3 | $ — |
| AOCI | $ 3 | |

Future benefit payments, which include any prescription drug benefits, and any offset from drug subsidiary receipts, are immaterial for each of the years 2018-2027.

**Benefit Plan Assets**

Pension plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended. The Company's investment policies for the pension plan cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The composition of the Company's pension plan assets as of December 31, 2017 , along with the targeted mix of assets for the plan, is presented below:

| | Target | 2017 |
|---|---|---|
| **Pension plan assets:** | | |
| Domestic equity | 26% | 31% |
| International equity | 25 | 25 |
| Fixed income | 23 | 24 |
| Special situations | 3 | 1 |
| Real estate investments | 14 | 13 |
| Private equity | 9 | 6 |
| Total | 100% | 100% |

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns and interest rates, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices. Management believes the portfolio is well-diversified with no significant concentrations of risk.

***Investment Strategies***

Detailed below is a description of the investment strategies for each major asset category for the pension benefit plan disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

***Benefit Plan Asset Fair Values***

Following are the fair value measurements for the pension plan assets as of December 31, 2017 . The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- ***Domestic and international equity.*** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- ***Fixed income.*** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- ***Real estate investments, private equity, and special situations investments.*** Investments in real estate, private equity, and special situations are generally classified as Net Asset Value as a Practical Expedient, since the underlying assets typically do not have publicly available observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. Techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, discounted cash flow analysis, prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals. The fair value of partnerships is determined by aggregating the value of the underlying assets less liabilities.

**NOTES (continued)**
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The fair values of pension plan assets as of December 31, 2017 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| **As of December 31, 2017:** | **Quoted Prices in Active Markets for Identical Assets (Level 1)** | **Significant Other Observable Inputs (Level 2)** | **Significant Unobservable Inputs (Level 3)** | **Net Asset Value as a Practical Expedient (NAV)** | **Total** |
| | | | *(in millions)* | | |
| Assets: | | | | | |
| Domestic equity (*) | $ 28 | $ 13 | $ — | $ — | $ 41 |
| International equity (*) | 18 | 16 | — | — | 34 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 10 | — | — | 10 |
| Corporate bonds | — | 14 | — | — | 14 |
| Pooled funds | — | 8 | — | — | 8 |
| Cash equivalents and other | 2 | — | — | — | 2 |
| Real estate investments | 5 | — | — | 14 | 19 |
| Special situations | — | — | — | 2 | 2 |
| Private equity | — | — | — | 8 | 8 |
| Total | $ 53 | $ 61 | $ — | $ 24 | $ 138 |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

## 3. CONTINGENCIES AND REGULATORY MATTERS

### General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as standards for air, water, land, and protection of other natural resources, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by $CO_2$ and other emissions and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. The ultimate outcome of such pending or potential litigation against the Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

During 2015, the Company indirectly acquired a 51% membership interest in RE Roserock LLC (Roserock), the owner of the Roserock facility in Pecos County, Texas, which was under construction by Recurrent Energy, LLC and was subsequently placed in service in November 2016. Prior to placing the facility in service, certain solar panels were damaged during installation. While the facility currently is generating energy consistent with operational expectations and PPA obligations, the Company is pursuing remedies under its insurance policies and other contracts to repair or replace these solar panels. In connection therewith, the Company is withholding payments of approximately $26 million from the construction contractor, who has placed a lien on the Roserock facility for the same amount. The amounts withheld are included in other accounts payable and other current liabilities on the Company's consolidated balance sheets. On May 18, 2017, Roserock filed a lawsuit in the state district court in Pecos County, Texas, against XL Insurance America, Inc. (XL) and North American Elite Insurance Company (North American Elite) seeking recovery from an insurance policy for damages resulting from a hail storm and certain installation practices by the construction contractor, McCarthy Building Companies, Inc. (McCarthy). On May 19, 2017, Roserock filed a separate lawsuit against McCarthy in the state district court in Travis County, Texas alleging breach of contract and breach of warranty for the damages sustained at the Roserock facility, which has since been moved to the U.S. District Court for the Western District of Texas. On May 22, 2017, McCarthy filed a counter lawsuit against Roserock, Array Technologies, Inc., Canadian Solar (USA), Inc., XL, and North American Elite in the U.S. District Court for the Western District of Texas alleging, among other things, breach of contract, and requesting foreclosure of mechanic's liens against Roserock. On July 18, 2017, the U.S. District Court for the Western District of Texas consolidated the two pending lawsuits. On December 11, 2017, the U.S. District Court for the Western District of Texas dismissed McCarthy's claims against Canadian Solar (USA), Inc. and dismissed cross-claims that XL and North American Elite had sought to bring against Roserock. The Company intends to vigorously pursue and defend these matters, the ultimate outcome of which cannot be determined at this time.

### FERC Matters

The Company and certain of its generation subsidiaries are subject to regulation by the FERC. The Company has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies and the Company filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In 2015, the FERC issued an order finding that the traditional electric operating companies' and the Company's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The FERC directed the traditional electric operating companies and the Company to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional electric operating companies and the Company filed a request for rehearing and filed their response with the FERC in 2015.

In December 2016, the traditional electric operating companies and the Company filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' and the Company's potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. On May 17, 2017, the FERC accepted the traditional electric operating companies' and the Company's compliance filing accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

On October 25, 2017, the FERC issued an order in response to the traditional electric operating companies' and the Company's June 29, 2017 triennial updated market power analysis. The FERC directed the traditional electric operating companies and the Company to show cause within 60 days why market-based rate authority should not be revoked in certain areas adjacent to the area presently under mitigation in accordance with the February 2, 2017 order or to provide a mitigation plan to further address market power concerns. On November 10, 2017, the traditional electric operating companies and the Company responded to the FERC and proposed to resolve matters by applying the alternative mitigation authorized by the February 2, 2017 order to the adjacent areas made the subject of the October 25, 2017 order.

The ultimate outcome of these matters cannot be determined at this time.

## 4. JOINT OWNERSHIP AGREEMENTS

The Company is a 65% owner of Plant Stanton A, a natural gas-fired combined-cycle unit with a nameplate capacity of 659 MWs. The unit is co-owned by the Orlando Utilities Commission ( 28% ), the Florida Municipal Power Agency ( 3.5% ), and the Kissimmee Utility Authority ( 3.5% ). The Company has a service agreement with SCS whereby SCS is responsible for the operation and maintenance of Plant Stanton A. As of December 31, 2017 , $155 million was recorded in plant in service with associated accumulated depreciation of $55 million . These amounts represent the Company's share of total plant assets and each owner is responsible for providing its own financing. The Company's proportionate share of Plant Stanton A's operating expense is included in the corresponding operating expenses in the consolidated statements of income.

## 5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and various state income tax returns, some of which are combined, unitary, or consolidated. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

**Federal Tax Reform Legislation**

Following the enactment of the Tax Reform Legislation, the SEC staff issued Staff Accounting Bulletin 118 – "Income Tax Accounting Implications of the Tax Cuts and Jobs Act" (SAB 118), which provides for a measurement period of up to one year from the enactment date to complete accounting under GAAP for the tax effects of the legislation. Due to the complex and comprehensive nature of the enacted tax law changes, and their application under GAAP, Southern Company considers all amounts recorded in the financial statements as a result of the Tax Reform Legislation to be "provisional" as discussed in SAB 118 and subject to revision. The Company is awaiting additional guidance from industry and income tax authorities in order to finalize its accounting. The ultimate impact of the Tax Reform Legislation on deferred income tax assets and liabilities cannot be determined at this time.

**Current and Deferred Income Taxes**

Details of income tax provisions are as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| Federal — | | | |
| Current (*) | **$ (566)** | $ 928 | $ 12 |
| Deferred (*) | **(312)** | (1,098) | 10 |
| | **(878)** | (170) | 22 |
| State — | | | |
| Current | **(110)** | (60) | (32) |
| Deferred | **49** | 35 | 31 |
| | **(61)** | (25) | (1) |
| Total | **$ (939)** | $ (195) | $ 21 |

(*) ITCs and PTCs generated in the current tax year and carried forward from prior tax years that cannot be utilized in the current tax year are reclassified from current to deferred taxes in federal income tax expense above. ITCs and PTCs reclassified in this manner include $316 million for 2017 , $1.13 billion for 2016 , and $246 million for 2015. These ITCs and PTCs are included in the following table of temporary differences as unrealized tax credits.

**NOTES (continued)**
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The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| Deferred tax liabilities — | | |
| Accelerated depreciation and other property basis differences | **$ 1,922** | $ 2,440 |
| Levelized capacity revenues | **26** | 28 |
| Other | **6** | 27 |
| Total deferred income tax liabilities | **1,954** | 2,495 |
| Deferred tax assets — | | |
| Federal effect of state deferred taxes | **42** | 53 |
| Basis difference on ITCs | **184** | 292 |
| Alternative minimum tax carryforward | **21** | 15 |
| Unrealized tax credits | **2,002** | 1,685 |
| Federal net operating loss (NOL) | **333** | 808 |
| Deferred state tax assets | **77** | 60 |
| Other partnership basis differences | **24** | 16 |
| Other | **10** | 8 |
| Total deferred income tax assets | **2,693** | 2,937 |
| Valuation Allowance | **(13)** | — |
| Net deferred income tax assets | **2,680** | 2,937 |
| Total deferred income tax asset (liability) | **$ 726** | $ 442 |
| | | |
| Recognized in the consolidated balance sheets: | | |
| Accumulated deferred income taxes – assets | **$ 925** | $ 594 |
| Accumulated deferred income taxes – liability | **$ (199)** | $ (152) |

Deferred tax liabilities are primarily the result of property-related timing differences, which increased due to bonus depreciation. However, the implementation of the Tax Reform Legislation significantly reduced the amount of accumulated deferred income taxes at December 31, 2017.

Deferred tax assets consist primarily of timing differences related to the carryforward of unrealized federal ITCs, PTCs, net operating loss, and net basis differences on federal ITCs.

***Tax Credit Carryforwards***

At December 31, 2017, the Company had federal ITC and PTC carryforwards, which are expected to result in $2.0 billion of federal income tax benefits. The federal ITC carryforwards begin expiring in 2034 but are expected to be fully utilized by 2027. The PTC carryforwards begin expiring in 2036 but are also expected to be fully utilized by 2027. The acquisition of additional renewable projects could further delay the utilization of existing tax credit carryforwards. The ultimate outcome of these matters cannot be determined at this time.

***Net Operating Loss***

After carrying back portions of the federal NOL generated in 2016, Southern Company had a consolidated federal NOL carryforward of approximately $2.3 billion at December 31, 2017. The federal NOL will expire in 2037 but is expected to be fully utilized by 2019. The ultimate outcome of this matter cannot be determined at this time.

The Company had state NOL carryforwards of approximately $1.3 billion at December 31, 2017, which will expire from 2029 to 2035. These carryforwards resulted in deferred tax assets of approximately $61 million as of December 31, 2017. The state NOL carryforwards by state jurisdiction were as follows:

| Jurisdiction | Approximate NOL Carryforwards | Approximate Net State Income Tax Benefit | Tax Year NOL Expires |
|---|---|---|---|
| | *(in millions)* | | |
| Oklahoma | $ 978 | $ 46 | 2035 |
| Florida | 283 | 12 | 2033 |
| South Carolina | 48 | 2 | 2035 |
| Other states | 23 | 1 | 2029-2035 |
| Balance at year end | $ 1,332 | $ 61 | |

**Effective Tax Rate**

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| Federal statutory rate | **35.0 %** | 35.0 % | 35.0 % |
| State income tax, net of federal deduction | **(22.2)** | (9.1) | (0.3) |
| Amortization of ITC | **(31.8)** | (20.6) | (5.0) |
| ITC basis difference | **(10.0)** | (89.0) | (21.5) |
| Production tax credits | **(72.5)** | (23.3) | (0.6) |
| Tax Reform Legislation | **(416.1)** | — | — |
| Noncontrolling interests | **(8.6)** | (6.2) | (1.7) |
| Other | **0.5** | 4.6 | 2.5 |
| Effective income tax rate (benefit) | **(525.7)%** | (108.6)% | 8.4 % |

The Company's effective tax rate decreased in 2017 primarily due to the Tax Reform Legislation. The decrease in 2016 was primarily due to changes in federal ITCs and PTCs.

The Company's deferred federal ITCs are amortized to income tax expense over the life of the respective asset. ITCs amortized in this manner amounted to $57 million in 2017, $37 million in 2016, and $19 million in 2015. Also, the Company received cash related to federal ITCs under the renewable energy incentives of $162 million for the year ended December 31, 2015. While no cash was received related to these incentives in 2017 or 2016, the Company recognized tax credits. Furthermore, the tax basis of the asset is reduced by 50% of the ITCs received, resulting in a net deferred tax asset. The Company has elected to recognize the tax benefit of this basis difference as a reduction to income tax expense in the year in which the plant reaches commercial operation. The tax benefit of the related basis differences reduced income tax expense by $18 million in 2017, $173 million in 2016, and $54 million in 2015. The tax benefit of PTCs reduced income tax expense by $129 million in 2017, $42 million in 2016 and $1 million in 2015. See "Unrecognized Tax Benefits" herein for further information.

**Legal Entity Reorganization**

In September 2017, Southern Power began a legal entity reorganization of various direct and indirect subsidiaries that own and operate substantially all of the solar facilities, including certain subsidiaries owned in partnership with various third parties. The reorganization included the purchase of all of the redeemable noncontrolling interests, representing 10% of the membership interests, in Southern Turner Renewable Energy, LLC. The reorganization is expected to be substantially completed in the first quarter 2018 and is expected to result in estimated tax benefits totaling between $50 million and $55 million related to certain changes in state apportionment rates and net operating loss carryforward utilization that will be recorded in the first quarter 2018. The ultimate outcome of this matter cannot be determined at this time.

### Unrecognized Tax Benefits

Changes during the year in unrecognized tax benefits were as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| Balance at beginning of year | **$ 17** | $ 8 | $ 5 |
| Tax positions increase from current periods | **—** | 17 | 9 |
| Tax positions decrease from prior periods | **(17)** | (8) | (6) |
| Balance at end of year | **$ —** | $ 17 | $ 8 |

The increase in unrecognized tax benefits from current periods for all years presented, and the decrease from prior periods for all years presented, primarily relate to federal income tax benefits from deferred ITCs and would all impact the Company's effective tax rate, if recognized. The impact on the effective tax rate is determined based on the amount of ITCs which are uncertain.

The Company classifies interest on tax uncertainties as interest expense. Accrued interest for unrecognized tax benefits was immaterial for all periods presented. The Company did no t accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months . The settlement of federal and state audits could impact the balances. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2016. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2011.

## 6. FINANCING

Southern Power Company's senior notes, bank term loans, commercial paper, and Facility (as defined herein) are unsecured senior indebtedness, which rank equally with all other unsecured and unsubordinated debt of Southern Power Compan y. The Company's subsidiaries are not issuers, borrowers, or obligors, as applicable, under the senior notes, borrowings from financial institutions , commercial paper, or the Facility. The se nior notes, borrowings from financial institutions, commercial paper, and the Facility are effectively subordinated to any future secured debt of Southern Power Company and any potential claims of creditors of the Company's subsidiaries. As of December 31, 2017 , the Company had no secured debt .

### Securities Due Within One Year

At December 31, 2017 , the Company had $420 million in term loans and $350 million of senior notes due within one year. At December 31, 2016 , the Company had a $60 million term loan, $ 500 million of senior notes, and $1 million of long-term notes due within one year.

Maturities of long-term debt for the next five years are as follows:

| | December 31, 2017 |
|---|---|
| | *(in millions)* |
| 2018 | $ 770 |
| 2019 | 600 |
| 2020 | 825 |
| 2021 | 300 |
| 2022 (*) | 677 |

(*) Represents euro-denominated debt at the U.S. dollar denominated hedge settlement amount.

### Senior Notes

In November 2017, the Company issued $525 million aggregate principal amount of Series 2017A Floating Rate Senior Notes due December 20, 2020, which bear interest based on three-month LIBOR. The net proceeds were used to redeem all of the $500 million aggregate principal amount of Series 2015D 1.85% Senior Notes due December 1, 2017 and to repay a portion of the Company's outstanding short-term debt.

**NOTES (continued)**
**Southern Power Company and Subsidiary Companies 2017 Annual Report**

At December 31, 2017 and 2016 , the Company had $5.5 billion and $5.3 billion of senior notes outstanding, respectively, which included senior notes due within one year.

**Other Long-Term Notes**

In September 2017, the Company amended its $60 million aggregate principal amount floating rate term loan to, among other things, increase the aggregate principal amount to $100 million and extend the maturity date from September 2017 to October 2018. The additional $40 million of proceeds were used to repay existing indebtedness and for other general corporate purposes.

At December 31, 2017 , outstanding term loans were included in securities due within one year.

The outstanding term loans as of December 31, 2017 have a covenant that limits debt levels to 65% of total capitalization, as defined in the agreements. For purposes of this definition, debt excludes any project debt incurred by certain subsidiaries of the company to the extent such debt is non-recourse to the company, and capitalization excludes the capital stock or other equity attributable to such subsidiary.

At December 31, 2017 , the Company was in compliance with its debt limits.

**Bank Credit Arrangements**

***Company Credit Facilities***

At December 31, 2017 , the Company had a committed credit facility (Facility) of $750 million expiring in 2022, of which $22 million has been used for letters of credit and $728 million remains unused. In May 2017, the Company amended the Facility, which, among other things, extended the maturity date from 2020 to 2022 and increased the Company's borrowing ability under the Facility to $750 million from $600 million . Proceeds from the Facility may be used for working capital and general corporate purposes as well as liquidity support for the Company's commercial paper program. As of December 31, 2016 , $78 million was used for letters of credit and $522 million remained unused. The Facility does not contain a material adverse change clause at the time of borrowing. Subject to applicable market conditions, the Company expects to renew or replace the Facility, as needed, prior to expiration. In connection therewith, the Company may extend the maturity date and/or increase or decrease the lending commitment thereunder. The Company's subsidiaries are not parties to the Facility.

The Company is required to pay a commitment fee on the unused balance of the Facility. This fee is less than 1/4 of 1%. The Facility contains a covenant that limits the ratio of debt to capitalization (each as defined in the Facility) to a maximum of 65% . For purposes of this definition, debt excludes any project debt incurred by certain subsidiaries of the Company to the extent such debt is non-recourse to the Company, and capitalization excludes the capital stock or other equity attributable to such subsidiary. At December 31, 2017 , the Company was in compliance with its debt limits.

The Company also has a $120 million continuing letter of credit facility expiring in 2019 for standby letters of credit. At December 31, 2017 , $101 million has been used for letters of credit, primarily as credit support for PPA requirements, and $19 million remains unused. At December 31, 2016, the total amount available under this facility was $82 million . The Company's subsidiaries are not parties to this letter of credit facility.

In addition, at both December 31, 2017 and 2016, the Company has $ 113 million of cash collateral posted related to PPA requirements, which is included in other deferred charges and assets in the consolidated balance sheets.

***Commercial Paper Program***

The Company's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes. The Company's subsidiaries are not parties to the commercial paper program. Commercial paper is included in notes payable in the consolidated balance sheets as noted below:

| | Commercial Paper at the End of the Period | |
|---|---|---|
| | **Amount Outstanding** | **Weighted Average Interest Rate** |
| | *(in millions)* | |
| **December 31, 2017** | **$ 105** | **2.0%** |
| December 31, 2016 | $ — | N/A |

**NOTES (continued)**
**Southern Power Company and Subsidiary Companies 2017 Annual Report**

***Subsidiary Project Credit Facilities***

In connection with the construction of solar facilities by RE Tranquillity LLC, RE Garland Holdings LLC, and RE Roserock LLC, indirect subsidiaries of the Company, each subsidiary had entered into separate credit agreements (Project Credit Facilities), which were non-recourse to the Company (other than the subsidiary party to the agreement). Each Project Credit Facility provided (a) a senior secured construction loan credit facility, (b) a senior secured bridge loan facility, and (c) a senior secured letter of credit facility that was secured by the membership interests of the respective project company, with proceeds directed to finance project costs related to the respective solar facilities. Each Project Credit Facility was secured by the assets of the applicable project subsidiary and membership interests of the applicable project subsidiary. The Tranquillity and Garland Project Credit Facilities were fully repaid on October 14, 2016 and December 29, 2016, respectively. The table below summarizes the Roserock Project Credit Facility as of December 31, 2016, which was extended to January 31, 2017 and fully repaid on January 17, 2017.

| | Construction Loan Facility | Bridge Loan Facility | Total Loan Facility | Loan Facility Undrawn | Letter of Credit Facility | Letter of Credit Facility Undrawn |
|---|---|---|---|---|---|---|
| | | | | *(in millions)* | | |
| December 31, 2016 | $ 63 | $ 180 | $ 243 | $ 34 | $ 23 | $ 16 |

The Project Credit Facilities had no amount outstanding at December 31, 2017 and $209 million outstanding with a weighted average interest rate of 2.1% as of December 31, 2016 .

**Assets Subject to Lien**

Under the terms of the PPA and the expansion PPA for the Mankato project, approximately $442 million of assets, primarily related to property, plant, and equipment, are subject to lien at December 31, 2017 . See Note 11 for additional information.

Roserock is in a litigation dispute with McCarthy regarding damage to certain solar panels during installation. In connection therewith, Roserock is withholding payments of approximately $26 million from McCarthy, and McCarthy has filed mechanic's liens on the Roserock facility for the same amount. See Note 3 for additional information.

**Dividend Restrictions**

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

**7. COMMITMENTS**

**Fuel Agreements**

SCS, as agent for the Company and the traditional electric operating companies, has entered into various fuel transportation and procurement agreements to supply a portion of the fuel (primarily natural gas) requirements for the Company's generating facilities. These purchase obligations are not recognized on the Company's consolidated balance sheets. The Company incurred fuel expense of $621 million , $456 million , and $441 million for the years ended December 31, 2017 , 2016 , and 2015 , respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and Southern Company's traditional electric operating companies. Under these agreements, each of the traditional electric operating companies and the Company may be jointly and severally liable. Southern Company has entered into keep-well agreements with each of the traditional electric operating companies to ensure they will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of the Company as a contracting party under these agreements.

**Operating Leases**

The Company has operating lease agreements with various terms and expiration dates. Total rent expense was $29 million , $22 million , and $7 million for the years ended December 31, 2017 , 2016 , and 2015 , respectively. These amounts include contingent rent expense related to land leases based on wind production and escalation in the Consumer Price Index for All Urban Consumers. The Company excludes contingent rent but includes step rents, fixed escalations, lease concessions, and lease extensions in its computation of minimum lease payments, which are recognized on a straight-line basis over the minimum lease term. As of December 31, 2017 , estimated minimum lease payments under operating leases were $22 million in each of 2018 , 2019 , and 2020 , $23 million in each of 2021 and 2022 , and $815 million in 2023 and thereafter. The majority of the committed future expenditures are related to land leases for solar and wind facilities.

**Redeemable Noncontrolling Interests**

See Note 10.

## 8. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 2017 , assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

| | Fair Value Measurements Using | | | |
|---|---|---|---|---|
| **As of December 31, 2017:** | **Quoted Prices in Active Markets for Identical Assets (Level 1)** | **Significant Other Observable Inputs (Level 2)** | **Significant Unobservable Inputs (Level 3)** | **Total** |
| | | *(in millions)* | | |
| Assets: | | | | |
| Energy-related derivatives | $ — | $ 3 | $ — | $ 3 |
| Foreign currency derivatives | — | 129 | — | 129 |
| Cash equivalents | 21 | — | — | 21 |
| Total | $ 21 | $ 132 | $ — | $ 153 |
| Liabilities: | | | | |
| Energy-related derivatives | $ — | $ 13 | $ — | $ 13 |
| Foreign currency derivatives | — | 23 | — | 23 |
| Contingent consideration | — | — | 22 | 22 |
| Total | $ — | $ 36 | $ 22 | $ 58 |

**NOTES (continued)**
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As of December 31, 2016 , assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

| | Fair Value Measurements Using | | | |
|---|---|---|---|---|
| As of December 31, 2016: | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Total |
| | | *(in millions)* | | |
| Assets: | | | | |
| Energy-related derivatives | $ — | $ 21 | $ — | $ 21 |
| Interest rate derivatives | — | 1 | — | 1 |
| Cash equivalents | 628 | — | — | 628 |
| Total | $ 628 | $ 22 | $ — | $ 650 |
| Liabilities: | | | | |
| Energy-related derivatives | $ — | $ 5 | $ — | $ 5 |
| Foreign currency derivatives | — | 58 | — | 58 |
| Contingent consideration | — | — | 18 | 18 |
| Total | $ — | $ 63 | $ 18 | $ 81 |

**Valuation Methodologies**

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard over-the-counter products that are valued using observable market data and assumptions commonly used by market participants. The fair value of interest rate derivatives reflects the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk, and occasionally, implied volatility of interest rate options. The fair value of cross-currency swaps reflects the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future foreign currency exchange rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk, and discount rates. The interest rate derivatives and cross-currency swaps are categorized as Level 2 under Fair Value Measurements as these inputs are based on observable data and valuations of similar instruments. See Note 9 for additional information on how these derivatives are used.

The Company has contingent payment obligations related to certain acquisitions whereby the Company is primarily obligated to make generation-based payments to the seller commencing at the commercial operation date through 2026. The obligation is categorized as Level 3 under Fair Value Measurements as the fair value is determined using significant unobservable inputs for the forecasted facility generation in MW-hours, as well as other inputs such as a fixed dollar amount per MW-hour, and a discount rate, and is evaluated periodically. The fair value of contingent consideration reflects the net present value of expected payments and any periodic change arising from forecasted generation is expected to be immaterial.

As of December 31, 2017 and 2016 , other financial instruments for which the carrying amount did not equal fair value were as follows:

| | Carrying Amount | Fair Value |
|---|---|---|
| | *(in millions)* | |
| Long-term debt, including securities due within one year: | | |
| **2017** | **$ 5,841** | **$ 6,079** |
| 2016 | $ 5,628 | $ 5,691 |

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates available to the Company.

## 9. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk, and occasionally foreign currency exchange rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the consolidated balance sheets as either assets or liabilities and are presented on a net basis. See Note 8 for additional fair value information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities. The cash impacts of settled foreign currency derivatives are classified as operating or financing activities to correspond with classification of the hedged interest or principal, respectively. See Note 1 under "Financial Instruments" for additional information.

### Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, natural gas, and other fuel price changes. The Company has limited exposure to market volatility in energy-related commodity prices because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, the Company has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of uncontracted generating capacity.

Energy-related derivative contracts are accounted for under one of two methods:

- *Cash Flow Hedges* – Gains and losses on energy-related derivatives designated as cash flow hedges which are used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in the consolidated statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the consolidated statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2017 , the net volume of energy-related derivative contracts for natural gas positions totaled 14 million mmBtu, all of which expire in 2018 . At December 31, 2017 , the net volume of energy-related derivative contracts for power positions was 3 million MWHs, all of which expire in 2018 .

In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess natural gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 10 million mmBtu.

For cash flow hedges, gains (losses) expected to be reclassified from accumulated OCI to earnings for the 12 -month period ending December 31, 2018 is $(7) million .

### Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to earnings. Fair value gains or losses on derivatives that are not designated or fail to qualify as hedges are recognized in the consolidated statements of income as incurred. At December 31, 2017 , the Company did not have any interest rate derivatives outstanding and does not have any deferred gains and losses in AOCI related to cash flow hedges that would be reclassified from AOCI to interest expense.

### Foreign Currency Derivatives

The Company may also enter into foreign currency derivatives to hedge exposure to changes in foreign currency exchange rates, such as that arising from the issuance of debt denominated in a currency other than U.S. dollars. Derivatives related to forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time that the hedged transactions affect earnings, including foreign currency gains or losses arising from changes in the U.S. currency exchange rates. Any ineffectiveness is recorded directly to earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness.

At December 31, 2017 , the following foreign currency derivatives were outstanding:

| | Pay Notional | Pay Rate | Receive Notional | Receive Rate | Hedge Maturity Date | Fair Value Gain (Loss) at December 31, 2017 |
|---|---|---|---|---|---|---|
| | *(in millions)* | | *(in millions)* | | | *(in millions)* |
| ***Cash Flow Hedges of Existing Debt*** | | | | | | |
| | $ 677 | 2.95% | € 600 | 1.00% | June 2022 | $ 55 |
| | 564 | 3.78% | 500 | 1.85% | June 2026 | 51 |
| Total | $ 1,241 | | € 1,100 | | | $ 106 |

The estimated pre-tax gains (losses) related to foreign currency derivatives that will be reclassified from accumulated OCI to earnings for the next 12 -month period ending December 31, 2018 total $(23) million .

### Derivative Financial Statement Presentation and Amounts

The Company enters into energy-related and interest rate derivative contracts that may contain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Fair value amounts of derivative assets and liabilities on the consolidated balance sheets are presented net to the extent that there are netting arrangements or similar agreements with counterparties.

At December 31, 2017 and 2016 , the fair value of energy-related, interest rate, and foreign currency derivatives reflected in the consolidated balance sheets is as follows:

**NOTES (continued)**
**Southern Power Company and Subsidiary Companies 2017 Annual Report**

| | 2017 | | 2016 | |
|---|---|---|---|---|
| **Derivative Category and Balance Sheet Location** | **Assets** | **Liabilities** | Assets | Liabilities |
| | | *(in millions)* | | |
| **Derivatives designated as hedging instruments in cash flow and fair value hedges** | | | | |
| Energy-related derivatives: | | | | |
| Other current assets/Other current liabilities | **$ 3** | **$ 11** | $ 18 | $ 4 |
| Foreign currency derivatives: | | | | |
| Other current assets/Other current liabilities | **—** | **23** | — | 25 |
| Other deferred charges and assets/Other deferred credits and liabilities | **129** | **—** | — | 33 |
| **Total derivatives designated as hedging instruments in cash flow and fair value hedges** | **$ 132** | **$ 34** | $ 18 | $ 62 |
| **Derivatives not designated as hedging instruments** | | | | |
| Energy-related derivatives: | | | | |
| Other current assets/Other current liabilities | **$ —** | **$ 2** | $ 3 | $ 1 |
| Interest rate derivatives: | | | | |
| Other current assets/Other current liabilities | **—** | **—** | 1 | — |
| **Total derivatives not designated as hedging instruments** | **$ —** | **$ 2** | $ 4 | $ 1 |
| **Gross amounts of recognized assets and liabilities** | **$ 132** | **$ 36** | $ 22 | $ 63 |
| **Gross amounts offset** | **$ (3)** | **$ (3)** | $ (5) | $ (5) |
| **Net amounts of assets and liabilities** | **$ 129** | **$ 33** | $ 17 | $ 58 |

For the years ended December 31, 2017 , 2016 , and 2015 , the pre-tax effects of energy-related, interest rate, and foreign currency derivatives designated as cash flow hedging instruments on the consolidated statements of income were as follows:

| Derivatives in Cash Flow Hedging Relationships | Gain (Loss) Recognized in OCI on Derivative (Effective Portion) | | | Gain (Loss) Reclassified from AOCI into Income (Effective Portion) | | | |
|---|---|---|---|---|---|---|---|
| **Derivative Category** | **2017** | 2016 | 2015 | **Statements of Income Location** | **2017** | 2016 | 2015 |
| | | *(in millions)* | | | | *(in millions)* | |
| Energy-related derivatives | **$ (38)** | $ 14 | $ — | Amortization | **$ (17)** | $ 2 | $ — |
| Interest rate derivatives | **—** | — | — | Interest expense, net of amounts capitalized | **—** | (1) | (1) |
| Foreign currency derivatives | **140** | (58) | — | Interest expense, net of amounts capitalized | **(23)** | (13) | — |
| | | | | Other income (expense), net | **159** | (82) | — |
| Total | **$ 102** | $ (44) | $ — | | **$ 119** | $ (94) | $ (1) |

There was no material ineffectiveness recorded in earnings for any period presented.

The pre-tax effects of energy-related derivatives and interest rate derivatives not designated as hedging instruments on the Company's consolidated statements of income were not material for any year presented.

**Contingent Features**

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2017 , there was no collateral posted with the Company's derivative counterparties.

At December 31, 2017 , the fair value of derivative liabilities with contingent features was $8 million . However, the fair value of derivative liabilities with contingent features, including certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade because of joint and several liability features underlying these derivatives, was $12 million at December 31, 2017 .

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

The Company maintains accounts with certain regional transmission organizations to facilitate financial derivative transactions. Based on the value of the positions in these accounts and the associated margin requirements, the Company may be required to post collateral. At December 31, 2017 , cash collateral posted was immaterial.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

## 10. NONCONTROLLING INTERESTS

In April 2017, approximately $114 million was reclassified from redeemable noncontrolling interests to non-redeemable noncontrolling interests due to the expiration of an option allowing SunPower Corporation to require the Company to purchase its redeemable noncontrolling interest at fair market value. In addition, Turner Renewable Energy, LLC owned a 10% redeemable noncontrolling interest in certain of the Company's solar facilities. These noncontrolling interests were redeemed in October 2017 at fair market value pursuant to the partnership agreement. As of December 31, 2017 , there were no outstanding redeemable noncontrolling interests.

**NOTES (continued)**
**Southern Power Company and Subsidiary Companies 2017 Annual Report**

The following table presents the changes in redeemable noncontrolling interests for the years ended December 31:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| Beginning balance | $ 164 | $ 43 | $ 39 |
| Net income attributable to redeemable noncontrolling interests | 2 | 4 | 2 |
| Distributions to redeemable noncontrolling interests | (2) | (1) | — |
| Capital contributions from redeemable noncontrolling interests | 2 | 118 | 2 |
| Redemption of redeemable noncontrolling interests | (59) | — | — |
| Reclassification to non-redeemable noncontrolling interests | (114) | — | — |
| Change in fair value of redeemable noncontrolling interests | 7 | — | — |
| Ending balance | $ — | $ 164 | $ 43 |

The following table presents the attribution of net income to the Company and the noncontrolling interests for the years ended December 31:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | *(in millions)* | |
| Net income | $ 1,117 | $ 374 | $ 229 |
| Less: Net income attributable to noncontrolling interests | 44 | 32 | 12 |
| Less: Net income attributable to redeemable noncontrolling interests | 2 | 4 | 2 |
| Net income attributable to the Company | $ 1,071 | $ 338 | $ 215 |

## 11. ACQUISITIONS

During 2017 and 2016 , in accordance with its overall growth strategy, the Company or one of its wholly-owned subsidiaries, acquired or contracted to acquire the projects discussed below. Also, in March 2016, the Company acquired an additional 15% interest in Desert Stateline, 51% of which was initially acquired in 2015. As a result, the Company and the class B member are now entitled to 66% and 34% , respectively, of all cash distributions from Desert Stateline. In addition, the Company will continue to be entitled to substantially all of the federal tax benefits with respect to the transaction. Acquisition-related costs were expensed as incurred and were not material for any of the years presented.

The following table presents the Company's acquisition activity for the year ended, and subsequent to, December 31, 2017.

| Project Facility | Resource | Seller, Acquisition Date | Approximate Nameplate Capacity ( *MW* ) | Location | Ownership Percentage | Actual / Expected COD | PPA Contract Period |
|---|---|---|---|---|---|---|---|
| **Business Acquisitions During the Year Ended December 31, 2017** | | | | | | | |
| Bethel | Wind | Invenergy Wind Global LLC, January 6, 2017 | 276 | Castro County, TX | 100% | January 2017 | 12 years |
| Cactus Flats [(a)] | Wind | RES America Developments, Inc., July 31, 2017 | 148 | Concho County, TX | 100% | Third quarter 2018 | 12 years and 15 years |
| **Asset Acquisitions Subsequent to December 31, 2017** | | | | | | | |
| Gaskell West 1 | Solar | Recurrent Energy Development Holdings, LLC, January 26, 2018 | 20 | Kern County, CA | 100% of Class B [(b)] | March 2018 | 20 years |

(a) On July 31, 2017, the Company purchased 100% of the Cactus Flats facility and commenced construction. Upon placing the facility in service, the Company expects to close on a tax equity partnership agreement that has already been executed, subject to various customary conditions at closing, and will then own 100% of the class B membership interests.

(b) The Company owns 100% of the class B membership interest under a tax equity partnership agreement.

**Business Acquisitions During the Year Ended December 31, 2017**

The Company's aggregate purchase price for acquisitions during the year ended December 31, 2017 was $539 million . The fair values of the assets acquired and liabilities assumed were finalized in 2017 and recorded as follows:

| | | 2017 |
|---|---|---|
| | | *(in millions)* |
| Restricted cash | $ | 16 |
| CWIP | | 534 |
| Other assets | | 5 |
| Accounts payable | | (16) |
| Total purchase price | $ | 539 |

In 2017, total revenues of $15 million and net income of $17 million , primarily as a result of PTCs, was recognized in the consolidated statements of income by the Company related to the 2017 acquisitions. The Bethel facility did not have operating revenues or activities prior to completion of construction and being placed in service, and the Cactus Flats facility is still under construction. Therefore, supplemental pro forma information as though the acquisitions occurred as of the beginning of 2017 and for the comparable 2016 period is not meaningful and has been omitted.

**Construction Projects in Progress**

During the year ended December 31, 2017 , in accordance with its overall growth strategy, the Company continued construction on the 345 -MW Mankato expansion project and commenced construction on the Cactus Flats facility. Total aggregate construction costs for these facilities, excluding acquisition costs and including construction costs to complete the subsequently-acquired Gaskell West 1 solar project, are expected to be between $385 million and $430 million . At December 31, 2017 , construction costs included in CWIP related to these projects totaled $188 million . The ultimate outcome of these matters cannot be determined at this time.

**Development Projects**

During 2017, as part of the Company's renewable development strategy, the Company purchased wind turbine equipment from Siemens Wind Power, Inc. and Vestas-American Wind Technology, Inc. to be used for various development and construction projects, up to 900 MWs in total. Once these wind projects reach commercial operations, which is expected in 2021, they are expected to qualify for 80% PTCs.

During 2016, the Company entered into a joint development agreement with Renewable Energy Systems Americas, Inc. to develop and construct approximately 3,000 MWs of wind projects expected to be placed in service between 2018 and 2020. In addition, in 2016, the Company purchased wind turbine equipment from Siemens Wind Power, Inc. and Vestas-American Wind Technology, Inc. to be used for construction of the facilities. Once these wind projects reach commercial operations, they are expected to qualify for 100% PTCs.

The ultimate outcome of these matters cannot be determined at this time.

**NOTES (continued)**
**Southern Power Company and Subsidiary Companies 2017 Annual Report**

The following table presents the Company's acquisitions for the year ended December 31, 2016 .

| Project Facility | Resource | Seller, Acquisition Date | Approximate Nameplate Capacity ( *MW* ) | Location | Ownership Percentage | Actual COD | PPA Contract Period |
|---|---|---|---|---|---|---|---|
| **Acquisitions for the Year Ended December 31, 2016** | | | | | | | |
| Boulder 1 | Solar | SunPower Corporation, November 16, 2016 | 100 | Clark County, NV | 51% [(a)] | December 2016 | 20 years |
| Calipatria | Solar | Solar Frontier Americas Holding LLC, February 11, 2016 | 20 | Imperial County, CA | 100% [(b)] | February 2016 | 20 years |
| East Pecos | Solar | First Solar, Inc., March 4, 2016 | 120 | Pecos County, TX | 100% | March 2017 | 15 years |
| Grant Plains | Wind | Apex Clean Energy Holdings, LLC, August 26, 2016 | 147 | Grant County, OK | 100% | December 2016 | 20 years and 12 years [(c)] |
| Grant Wind | Wind | Apex Clean Energy Holdings, LLC, April 7, 2016 | 151 | Grant County, OK | 100% | April 2016 | 20 years |
| Henrietta | Solar | SunPower Corporation, July 1, 2016 | 102 | Kings County, CA | 51% [(a)] | July 2016 | 20 years |
| Lamesa | Solar | RES America Developments Inc., July 1, 2016 | 102 | Dawson County, TX | 100% | April 2017 | 15 years |
| Mankato [(d)] | Natural Gas | Calpine Corporation, October 26, 2016 | 375 | Mankato, MN | 100% | N/A [(e)] | 10 years |
| Passadumkeag | Wind | Quantum Utility Generation, LLC, June 30, 2016 | 42 | Penobscot County, ME | 100% | July 2016 | 15 years |
| Rutherford | Solar | Cypress Creek Renewables, LLC, July 1, 2016 | 74 | Rutherford County, NC | 100% [(b)] | December 2016 | 15 years |
| Salt Fork | Wind | EDF Renewable Energy, Inc., December 1, 2016 | 174 | Donley and Gray Counties, TX | 100% | December 2016 | 14 years and 12 years |
| Tyler Bluff | Wind | EDF Renewable Energy, Inc., December 21, 2016 | 125 | Cooke County, TX | 100% | December 2016 | 12 years |
| Wake Wind | Wind | Invenergy Wind Global LLC, October 26, 2016 | 257 | Floyd and Crosby Counties, TX | 90.1% [(f)] | October 2016 | 12 years |

(a) The Company owns 100% of the class A membership interests and a wholly-owned subsidiary of the seller owns 100% of the class B membership interests. The Company and the class B member are entitled to 51% and 49% , respectively, of all cash distributions from the project. In addition, the Company is entitled to substantially all of the federal tax benefits with respect to the transaction.
(b) The Company originally purchased 90% , with a minority owner owning 10% . During 2017, the Company acquired the remaining 10% ownership interest. See Note 10 for additional information.
(c) In addition to the 20 -year and 12 -year PPAs, the facility has a 10 -year contract with Allianz Risk Transfer (Bermuda) Ltd.
(d) Under the terms of the PPA and the expansion PPA, approximately $442 million of assets, primarily related to property, plant, and equipment, are subject to lien at December 31, 2017.
(e) The acquisition included a fully operational 375 -MW natural gas-fired combined-cycle facility.
(f) The Company owns 90.1% , with the minority owner, Invenergy Wind Global LLC, owning 9.9% .

**NOTES (continued)**
**Southern Power Company and Subsidiary Companies 2017 Annual Report**

**Acquisitions During the Year Ended December 31, 2016**

The Company's aggregate purchase price for acquisitions during the year ended December 31, 2016 was approximately $2.3 billion . The total aggregate purchase price including minority ownership contributions and the assumption of non-recourse construction debt to the Company was approximately $2.6 billion for these acquisitions. In connection with the Company's 2016 acquisitions, allocations of the purchase price to individual assets were finalized during the year ended December 31, 2017 with no changes to amounts originally reported for Boulder 1, Grant Plains, Grant Wind, Henrietta, Mankato, Passadumkeag, Salt Fork, Tyler Bluff, and Wake Wind. The fair values of the assets and liabilities acquired through the business combinations were recorded as follows:

| | 2016 | |
|---|---|---|
| | *(in millions)* | |
| CWIP | $ | 2,354 |
| Property, plant, and equipment | | 302 |
| Intangible assets [(a)] | | 128 |
| Other assets | | 52 |
| Accounts payable | | (16) |
| Debt | | (217) |
| Total purchase price | $ | 2,603 |
| | | |
| Funded by: | | |
| The Company [(b)] [(c)] | $ | 2,345 |
| Noncontrolling interests [(d)] [(e)] | | 258 |
| Total purchase price | $ | 2,603 |

(a) Intangible assets consist of acquired PPAs that will be amortized over 10 - and 20 -year terms. The estimated amortization for future periods is approximately $9 million per year. See Note 1 for additional information.
(b) At December 31, 2016, $461 million is included in acquisitions payable on the consolidated balance sheets.
(c) Includes approximately $281 million of contingent consideration, of which $29 million was payable at December 31, 2017.
(d) Includes approximately $51 million of non-cash contributions recorded as capital contributions from noncontrolling interests in the consolidated statements of stockholders' equity.
(e) Includes approximately $142 million of contingent consideration, all of which had been paid at December 31, 2016 by the noncontrolling interests.

## 12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2017 and 2016 is as follows:

| Quarter Ended | Operating Revenues | Operating Income | Income Tax (Benefit) | Net Income Attributable to the Company |
|---|---|---|---|---|
| | | | *(in millions)* | |
| **March 2017** | **$ 450** | **$ 65** | **$ (52)** | **$ 70** |
| **June 2017** | **529** | **112** | **(38)** | **82** |
| **September 2017** | **618** | **159** | **(39)** | **124** |
| **December 2017** (*) | **478** | **32** | **(810)** | **795** |
| | | | | |
| March 2016 | $ 315 | $ 47 | $ (23) | $ 50 |
| June 2016 | 373 | 81 | (41) | 89 |
| September 2016 | 500 | 134 | (102) | 176 |
| December 2016 | 389 | 28 | (29) | 23 |

(*) As a result of the Tax Reform Legislation, the Company recorded an income tax benefit of $ 743 million in the fourth quarter 2017. See Note 5 for additional information.

The Company's business is influenced by seasonal weather conditions.

**SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA 2013 - 2017**
**Southern Power Company and Subsidiary Companies 2017 Annual Report**

| | 2017 | 2016 | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|
| **Operating Revenues (in millions):** | | | | | |
| Wholesale — non-affiliates | $ 1,671 | $ 1,146 | $ 964 | $ 1,116 | $ 923 |
| Wholesale — affiliates | 392 | 419 | 417 | 383 | 346 |
| Total revenues from sales of electricity | 2,063 | 1,565 | 1,381 | 1,499 | 1,269 |
| Other revenues | 12 | 12 | 9 | 2 | 6 |
| Total | $ 2,075 | $ 1,577 | $ 1,390 | $ 1,501 | $ 1,275 |
| **Net Income Attributable to Southern Power (in millions)** [(a)] | $ 1,071 | $ 338 | $ 215 | $ 172 | $ 166 |
| **Cash Dividends on Common Stock (in millions)** | $ 317 | $ 272 | $ 131 | $ 131 | $ 129 |
| **Return on Average Common Equity (percent)** [(a)] | 22.39 | 9.79 | 10.16 | 10.39 | 10.73 |
| **Total Assets (in millions)** [(b)(c)] | $ 15,206 | $ 15,169 | $ 8,905 | $ 5,233 | $ 4,417 |
| **Property, Plant, and Equipment — In Service (in millions)** | $ 13,755 | $ 12,728 | $ 7,275 | $ 5,657 | $ 4,696 |
| **Capitalization (in millions):** | | | | | |
| Common stock equity | $ 5,138 | $ 4,430 | $ 2,483 | $ 1,752 | $ 1,564 |
| Redeemable noncontrolling interests | — | 164 | 43 | 39 | 29 |
| Noncontrolling interests | 1,360 | 1,245 | 781 | 219 | — |
| Long-term debt [(b)] | 5,071 | 5,068 | 2,719 | 1,085 | 1,607 |
| Total (excluding amounts due within one year) | $ 11,569 | $ 10,907 | $ 6,026 | $ 3,095 | $ 3,200 |
| **Capitalization Ratios (percent):** | | | | | |
| Common stock equity | 44.4 | 40.6 | 41.2 | 56.6 | 48.9 |
| Redeemable noncontrolling interests | — | 1.5 | 0.7 | 1.3 | 0.9 |
| Noncontrolling interests | 11.8 | 11.4 | 13.0 | 7.1 | — |
| Long-term debt [(b)] | 43.8 | 46.5 | 45.1 | 35.0 | 50.2 |
| Total (excluding amounts due within one year) | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| **Kilowatt-Hour Sales (in millions):** | | | | | |
| Wholesale — non-affiliates | 35,920 | 23,213 | 18,544 | 19,014 | 15,111 |
| Wholesale — affiliates | 12,811 | 15,950 | 16,567 | 11,194 | 9,359 |
| Total | 48,731 | 39,163 | 35,111 | 30,208 | 24,470 |
| **Plant Nameplate Capacity Ratings (year-end) (megawatts)** | 12,940 | 12,442 | 9,808 | 9,185 | 8,924 |
| **Maximum Peak-Hour Demand (megawatts):** | | | | | |
| Winter | 3,421 | 3,469 | 3,923 | 3,999 | 2,685 |
| Summer | 4,224 | 4,303 | 4,249 | 3,998 | 3,271 |
| **Annual Load Factor (percent)** | 49.1 | 50.0 | 49.0 | 51.8 | 54.2 |
| **Plant Availability (percent)** | 99.9 | 91.6 | 93.1 | 91.8 | 91.8 |
| **Source of Energy Supply (percent):** | | | | | |
| Natural gas | 67.7 | 79.4 | 89.5 | 86.0 | 88.5 |
| Solar, Wind, and Biomass | 22.8 | 12.1 | 4.3 | 2.9 | 1.1 |
| Purchased power — | | | | | |
| From non-affiliates | 7.8 | 6.8 | 4.7 | 6.4 | 6.4 |
| From affiliates | 1.7 | 1.7 | 1.5 | 4.7 | 4.0 |
| Total | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| Employees (year-end) [(d)] | 541 | — | — | — | — |

(a) As a result of the Tax Reform Legislation, the Company recorded an income tax benefit of $743 million in 2017.

(b) A reclassification of debt issuance costs from Total Assets to Long-term debt of $11 million and $12 million is reflected for years 2014 and 2013, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(c) A reclassification of deferred tax assets from Total Assets of $306 million and $- million is reflected for years 2014 and 2013, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(d) Prior to the employee transfer in December 2017, the Company had no employees, but was billed employee related costs from SCS.

# SOUTHERN COMPANY GAS

# FINANCIAL SECTION

**MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING**
**Southern Company Gas and Subsidiary Companies 2017 Annual Report**

The management of Southern Company Gas (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2017 .

/s/ Andrew W. Evans
Andrew W. Evans
Chairman, President, and Chief Executive Officer

/s/ Elizabeth W. Reese
Elizabeth W. Reese
Executive Vice President, Chief Financial Officer, and Treasurer

February 20, 2018

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the stockholder and the Board of Directors of Southern Company Gas and Subsidiary Companies

**Opinion on the Financial Statements**

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Southern Company Gas and Subsidiary Companies (the Company) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2017 and 2016 , the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for the year ended December 31, 2017 and the six month periods ended June 30, 2016 (Predecessor) and December 31, 2016 (Successor), and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements (pages II-593 to II-651 ) present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016 , and the results of its operations and its cash flows for the year ended December 31, 2017 and the six months ended June 30, 2016 (Predecessor) and December 31, 2016 (Successor), in conformity with accounting principles generally accepted in the United States of America.

**Basis for Opinion**

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We did not audit the financial statements of Southern Natural Gas Company, L.L.C. (SNG), the Company's investment in which is accounted for by the use of the equity method. The accompanying consolidated financial statements of the Company include its equity investment in SNG of $1,262 million and $1,394 million as of December 31, 2017 and December 31, 2016 , respectively, and its earnings from its equity method investment in SNG of $88 million and $56 million for the year ended December 31, 2017 and the six months ended December 31, 2016, respectively. Those statements were audited by other auditors whose report (which expresses an unqualified opinion on SNG's financial statements and contains an emphasis of matter paragraph concerning the extent of its operations and relationships with affiliated entities) have been furnished to us, and our opinion, insofar as it relates to the amounts included for SNG, is based solely on the report of the other auditors. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits and the report of the other auditors provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 20, 2018

We have served as the Company's auditor since 2016.

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the stockholder and the Board of Directors of Southern Company Gas and Subsidiary Companies

In our opinion, the consolidated statement of income, comprehensive income, common stockholders' equity, and cash flows present fairly, in all material respects, the results of operations and cash flows of Southern Company Gas (formerly AGL Resources Inc.) and its subsidiaries for the year ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule for the year ended December 31, 2015 presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audit. We conducted our audit of these financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Atlanta, Georgia
February 11, 2016

**DEFINITIONS**

| Term | Meaning |
|---|---|
| AFUDC | Allowance for funds used during construction |
| ASC | Accounting Standards Codification |
| ASU | Accounting Standards Update |
| Atlanta Gas Light | Atlanta Gas Light Company, a wholly-owned subsidiary of Southern Company Gas |
| Atlantic Coast Pipeline | Atlantic Coast Pipeline, LLC |
| Chattanooga Gas | Chattanooga Gas Company |
| Chicago Hub | A venture of Nicor Gas, which provides natural gas storage and transmission-related services to marketers and gas distribution companies |
| CUB | Citizens Utility Board, in Illinois |
| Dalton Pipeline | A 50% undivided ownership interest in a pipeline facility in Georgia |
| EBIT | Earnings before interest and taxes |
| EPA | U.S. Environmental Protection Agency |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| Fitch | Fitch Ratings, Inc. |
| GAAP | U.S. generally accepted accounting principles |
| Heating Degree Days | A measure of weather, calculated when the average daily temperatures are less than 65 degrees Fahrenheit |
| Heating Season | The period from November through March when natural gas usage and operating revenues are generally higher |
| Horizon Pipeline | Horizon Pipeline Company, LLC |
| Illinois Commission | Illinois Commerce Commission |
| IRS | Internal Revenue Service |
| ITC | Investment tax credit |
| LIBOR | London Interbank Offered Rate |
| LIFO | Last-in, first-out |
| LNG | Liquefied natural gas |
| LOCOM | Lower of weighted average cost or current market price |
| Marketers | Marketers selling retail natural gas in Georgia and certificated by the Georgia PSC |
| Merger | The merger of a wholly-owned, direct subsidiary of Southern Company, with and into Southern Company Gas, effective July 1, 2016, with Southern Company Gas continuing as the surviving corporation and a wholly-owned, direct subsidiary of Southern Company |
| MGP | Manufactured gas plant |
| mmBtu | Million British thermal units |
| Moody's | Moody's Investors Service, Inc. |
| natural gas distribution utilities | Southern Company Gas' seven natural gas distribution utilities (Nicor Gas, Atlanta Gas Light, Virginia Natural Gas, Elizabethtown Gas, Florida City Gas, Chattanooga Gas, and Elkton Gas) |
| New Jersey BPU | New Jersey Board of Public Utilities |
| Nicor Gas | Northern Illinois Gas Company, doing business as Nicor Gas Company |
| NYMEX | New York Mercantile Exchange, Inc. |
| OCI | Other comprehensive income |

**DEFINITIONS**
(continued)

| Term | Meaning |
|---|---|
| PennEast Pipeline | PennEast Pipeline Company, LLC |
| Piedmont | Piedmont Natural Gas Company, Inc. |
| Pivotal Utility Holdings | Pivotal Utility Holdings, Inc., a wholly-owned subsidiary of Southern Company Gas, doing business as Elizabethtown Gas, Elkton Gas, and Florida City Gas |
| PRP | Pipeline Replacement Program, Atlanta Gas Light's 15-year infrastructure replacement program, which ended in December 2013 |
| PSC | Public Service Commission |
| ROE | Return on equity |
| S&P | S&P Global Ratings, a division of S&P Global Inc. |
| SCS | Southern Company Services, Inc. (the Southern Company system service company) |
| SEC | U.S. Securities and Exchange Commission |
| Sequent | Sequent Energy Management, L.P. |
| SNG | Southern Natural Gas Company, L.L.C. |
| Southern Company | The Southern Company |
| Southern Company Gas Capital | Southern Company Gas Capital Corporation, a 100%-owned subsidiary of Southern Company Gas |
| Southern Company system | Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), Southern Electric Generating Company, Southern Nuclear, SCS, Southern Linc, PowerSecure, Inc. (as of May 9, 2016), and other subsidiaries |
| Southern Holdings | Southern Company Holdings, Inc. |
| Southern Linc | Southern Communications Services, Inc. |
| Southern Nuclear | Southern Nuclear Operating Company, Inc. |
| Southern Power | Southern Power Company and its subsidiaries |
| SouthStar | SouthStar Energy Services, LLC |
| STRIDE | Atlanta Gas Light's Strategic Infrastructure Development and Enhancement program |
| traditional electric operating companies | Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company |
| Tax Reform Legislation | The Tax Cuts and Jobs Act, which was signed into law on December 22, 2017 and became effective on January 1, 2018 |
| Triton | Triton Container Investments, LLC |
| VIE | Variable interest entity |
| Virginia Commission | Virginia State Corporation Commission |
| Virginia Natural Gas | Virginia Natural Gas, Inc. |
| WACOG | Weighted average cost of gas |

**MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS**
**Southern Company Gas and Subsidiary Companies 2017 Annual Report**

## OVERVIEW

### Business Activities

Southern Company Gas is an energy services holding company whose primary business is the distribution of natural gas through utilities in seven states – Illinois, Georgia, Virginia, New Jersey, Florida, Tennessee, and Maryland. Southern Company Gas and its subsidiaries (the Company) are also involved in several other complementary businesses.

The Company has four reportable segments – gas distribution operations, gas marketing services, wholesale gas services, and gas midstream operations – and one non-reportable segment, all other. See Note 12 to the financial statements for additional information.

Many factors affect the opportunities, challenges, and risks of the Company's business. These factors include the ability to maintain safety, to maintain constructive regulatory environments, to maintain and grow natural gas sales and number of customers, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, environmental standards, reliability, natural gas, and capital expenditures, including updating and expanding the natural gas distribution systems. The natural gas distribution utilities have various regulatory mechanisms that operate to address cost recovery. Effectively operating pursuant to these regulatory mechanisms and appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

### Merger, Acquisition, and Disposition Activities

On July 1, 2016, the Company completed the Merger, pursuant to which the Company became a wholly-owned subsidiary of Southern Company. Southern Company accounted for the Merger using the acquisition method of accounting whereby the assets acquired and liabilities assumed were recognized at fair value as of the acquisition date. Pushdown accounting was applied to create a new cost basis for the Company's assets, liabilities, and equity as of the acquisition date. Accordingly, the successor financial statements reflect the new basis of accounting, and successor and predecessor period financial results (separated by a heavy black line) are presented, but are not comparable. As a result of the application of acquisition accounting, certain discussions herein include disclosure of the predecessor and successor periods. See Note 11 to the financial statements under "Merger with Southern Company" for additional information.

In September 2016, the Company paid approximately $1.4 billion to acquire a 50% equity interest in SNG, which is the owner of a 7,000 -mile pipeline system connecting natural gas supply basins in Texas, Louisiana, Mississippi, and Alabama to markets in Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina, and Tennessee. The investment in SNG is accounted for using the equity method. On March 31, 2017, the Company made an additional $50 million contribution to maintain its 50% equity interest in SNG. See Note 4 to the financial statements under "Equity Method Investments – SNG" and Note 11 to the financial statements under "Investment in SNG" for additional information.

In October 2016, the Company completed its purchase of Piedmont's 15% interest in SouthStar for $160 million . See Note 4 to the financial statements under "Variable Interest Entities" for additional information.

On October 15, 2017, the Company's subsidiary, Pivotal Utility Holdings, entered into agreements for the sale of the assets of two of its natural gas distribution utilities, Elizabethtown Gas and Elkton Gas, to South Jersey Industries, Inc. for a total cash purchase price of $1.7 billion. As of December 31, 2017, the net book value of the assets to be disposed of in the sale was approximately $1.3 billion, which includes approximately $0.5 billion of goodwill. The goodwill is not deductible for tax purposes and, as a result, a deferred tax liability has not yet been provided. Through the completion of the asset sales, the Company intends to invest less than $0.1 billion in capital additions required for ordinary business operations of these assets. The completion of each asset sale is subject to the satisfaction or waiver of certain conditions, including, among other customary closing conditions, the receipt of required regulatory approvals, including the FERC, the Federal Communications Commission, the New Jersey BPU, and, with respect to the sale of Elkton Gas, the Maryland PSC. The Company and South Jersey Industries, Inc. made joint filings on December 22, 2017 and January 16, 2018 with the New Jersey BPU and the Maryland PSC, respectively, requesting regulatory approval. The asset sales are expected to be completed by the end of the third quarter 2018.

The ultimate outcome of these matters cannot be determined at this time.

### Operating Metrics

The Company continues to focus on several operating metrics, including Heating Degree Days, customer count, and volumes of natural gas sold.

The Company measures weather and the effect on its business using Heating Degree Days. Generally, increased Heating Degree Days result in higher demand for natural gas on the Company's distribution system. With the exception of the Company's utilities in Illinois and Florida, the Company has various regulatory mechanisms, such as weather normalization and straight-fixed-variable rate design, which limit its exposure to weather changes within typical ranges in each of its utilities' respective service territory. However, the utility customers in Illinois and the gas marketing services customers primarily in Georgia, Illinois, and Ohio can be impacted by warmer- or colder-than-normal weather. The Company utilizes weather hedges to reduce negative earnings impact in the event of warmer-than-normal weather, while retaining most of the earnings upside for these businesses.

The number of customers served by gas distribution operations and gas marketing services can be impacted by natural gas prices, economic conditions, and competition from alternative fuels. Gas marketing services' customers are primarily located in Georgia, Illinois, and Ohio.

The Company's natural gas volume metrics for gas distribution operations and gas marketing services illustrate the effects of weather and customer demand for natural gas. Wholesale gas services' physical sales volumes represent the daily average natural gas volumes sold to its customers.

See RESULTS OF OPERATIONS herein for additional information on these operating metrics.

**Seasonality of Results**

During the Heating Season, natural gas usage and operating revenues are generally higher as more customers are connected to the gas distribution systems and natural gas usage is higher in periods of colder weather. Occasionally in the summer, wholesale gas services' operating revenues are impacted due to peak usage by power generators in response to summer energy demands. The Company's base operating expenses, excluding cost of natural gas, bad debt expense, and certain incentive compensation costs, are incurred relatively evenly throughout the year. Seasonality also affects the comparison of certain balance sheet items across quarters, including receivables, unbilled revenues, natural gas for sale, and notes payable. However, these items are comparable when reviewing the Company's annual results. Thus, the Company's operating results can vary significantly from quarter to quarter as a result of seasonality, which is illustrated in the table below.

| | Percent Generated During Heating Season | | |
|---|---|---|---|
| | **Operating Revenues** | **EBIT** | **Net Income** |
| **Successor - 2017** | 67.3% | 69.6% | 73.7% |
| Successor - July 1, 2016 through December 31, 2016 | 67.1% | 81.5% | 96.5% |
| Predecessor - January 1, 2016 through June 30, 2016 | 70.0% | 107.0% | 138.9% |
| Predecessor - 2015 | 68.1% | 77.3% | 85.0% |

**Earnings**

Net income attributable to the Company for the successor year ended December 31, 2017 was $243 million , which included net income of $53 million from the Company's investment in SNG (including $18 million related to a non-cash charge recorded by SNG to establish a regulatory liability associated with the Tax Reform Legislation) and $44 million generated from the Company's continued investment in infrastructure replacement programs and base rate increases at Atlanta Gas Light, Elizabethtown Gas, and Virginia Natural Gas, less the associated increases in depreciation. Net income also reflects $130 million of additional tax expense resulting from the revaluation of deferred tax assets of $93 million related to the Tax Reform Legislation and $37 million associated with State of Illinois income tax legislation enacted in the third quarter 2017 and new income tax apportionment factors in several states resulting from the Company's inclusion in the consolidated Southern Company state tax filings. Also included in net income was $17 million of additional expense resulting from the pushdown of acquisition accounting. See FUTURE EARNINGS POTENTIAL – " Income Tax Matters " herein and Notes 5 and 11 to the financial statements for additional information.

Net income attributable to the Company for the successor period of July 1, 2016 through December 31, 2016 was $114 million , which included $26 million in earnings from the SNG investment, net of related interest expense, partially offset by $12 million of additional expense resulting from the impact of the pushdown of acquisition accounting and $27 million of Merger-related expenses.

Net income attributable to the Company for the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 were $131 million and $353 million , respectively, which included $41 million and $26 million , respectively, of Merger-related expenses, and $14 million and $20 million, respectively, of net income attributable to the SouthStar noncontrolling interest, which the Company purchased in October 2016. Net income for the predecessor periods reflected higher revenues from continued investment in infrastructure programs, partially offset by warm weather, net of hedging, and low earnings from wholesale gas services due to mark-to-market losses.

**RESULTS OF OPERATIONS**

**Operating Results**

A condensed income statement for the Company follows:

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | **Year Ended December 31, 2017** | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | Year Ended December 31, 2015 |
| | *(in millions)* | | *(in millions)* | |
| Operating revenues | **$ 3,920** | $ 1,652 | $ 1,905 | $ 3,941 |
| Cost of natural gas and other sales | **1,630** | 623 | 769 | 1,645 |
| Other operations and maintenance | **940** | 482 | 454 | 928 |
| Depreciation and amortization | **501** | 238 | 206 | 397 |
| Taxes other than income taxes | **184** | 71 | 99 | 181 |
| Merger-related expenses | **—** | 41 | 56 | 44 |
| Total operating expenses | **3,255** | 1,455 | 1,584 | 3,195 |
| Operating income | **665** | 197 | 321 | 746 |
| Earnings from equity method investments | **106** | 60 | 2 | 6 |
| Interest expense, net of amounts capitalized | **200** | 81 | 96 | 175 |
| Other income (expense), net | **39** | 14 | 5 | 9 |
| Earnings before income taxes | **610** | 190 | 232 | 586 |
| Income taxes | **367** | 76 | 87 | 213 |
| Net Income | **243** | 114 | 145 | 373 |
| Less: Net income attributable to noncontrolling interest | **—** | — | 14 | 20 |
| Net Income Attributable to Southern Company Gas | **$ 243** | $ 114 | $ 131 | $ 353 |

***Operating Revenues***

Operating revenues for the successor year ended December 31, 2017 and the successor period of July 1, 2016 through December 31, 2016 were $3.9 billion and $1.7 billion , respectively. For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, operating revenues were $1.9 billion and $3.9 billion , respectively.

For the successor year ended December 31, 2017 , natural gas revenues included recovery of $1.6 billion in cost of natural gas and $6 million in net revenues from wholesale gas services, net of $21 million of amortization associated with assets established in the application of acquisition accounting. Also included in natural gas revenues for the successor year ended December 31, 2017 were $99 million in additional revenues generated from gas distribution operations as a result of continued investment in infrastructure replacement programs and increases in base rate revenues at Atlanta Gas Light, Elizabethtown Gas, and Virginia Natural Gas. Natural gas revenues were partially offset by a $13 million negative impact of warmer-than-normal weather, net of hedging.

For the successor period of July 1, 2016 through December 31, 2016, natural gas revenues included recovery of $613 million in cost of natural gas and $24 million in net revenues from wholesale gas services, net of $5 million of amortization associated with assets established in the application of acquisition accounting. Natural gas revenues were partially offset by a $5 million decrease attributable to warmer-than-normal weather, net of hedging.

For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, natural gas revenues included recovery of $755 million and $1.6 billion , respectively, in cost of natural gas, as well as $32 million in net losses and $202 million in net revenues, respectively, from wholesale gas services. For the predecessor period of January 1, 2016 through June 30, 2016, natural gas revenues included a negative impact of $7 million attributable to warmer-than-normal weather, net of hedging. For the predecessor year ended December 31, 2015, natural gas revenues included a positive impact of $2 million also attributable to warmer-than-normal weather, net of hedging.

See "Segment Information" herein for additional information on wholesale gas services' revenues and losses.

Natural gas distribution rates include provisions to adjust billings for fluctuations in natural gas costs. Therefore, gas costs recovered through natural gas revenues generally equal the amount expensed in cost of natural gas and do not affect net income from gas distribution operations. See "Cost of Natural Gas" herein for additional information. Revenue impacts from weather and customer growth are described further below.

During Heating Season, natural gas usage and operating revenues are generally higher. Weather typically does not have a significant net income impact during the non-Heating Season. The following table presents the Heating Degree Days information for Illinois and Georgia, the primary locations where the Company's operations are impacted by weather.

| | Years Ended December 31, | | | | 2017 vs. normal | 2017 vs. 2016 | 2016 vs. 2015 |
|---|---|---|---|---|---|---|---|
| | Normal [(a)] | **2017** | 2016 | 2015 | **(warmer)** | **colder (warmer)** | (warmer) |
| | | *(in thousands)* | | | | | |
| Illinois [(b)] | 5,869 | **5,246** | 5,243 | 5,433 | **(10.6)%** | **0.1 %** | (3.5)% |
| Georgia | 2,614 | **1,970** | 2,175 | 2,204 | **(24.6)%** | **(9.4)%** | (1.3)% |

(a) Normal represents the 10-year average from January 1, 2007 through December 31, 2016 for Illinois at Chicago Midway International Airport and for Georgia at Atlanta Hartsfield-Jackson International Airport, based on information obtained from the National Oceanic and Atmospheric Administration, National Climatic Data Center.

(b) The 10-year average Heating Degree Days established by the Illinois Commission in Nicor Gas' 2009 rate case is 5,600 annually from 1998 through 2007.

The Company hedged its exposure to warmer-than-normal weather at Nicor Gas in Illinois; therefore, the weather-related negative pre-tax income impact on gas distribution operations was limited to $4 million ($2 million after tax), $1 million ($1 million after tax), $7 million ($5 million after tax), and a positive impact of $2 million ($1 million after tax) for the successor year ended December 31, 2017, the successor period of July 1, 2016 through December 31, 2016, the predecessor period of January 1, 2016 through June 30, 2016, and the predecessor year ended December 31, 2015, respectively.

The Company also hedged its exposure to warmer-than-normal weather at gas marketing services in Georgia and Illinois; therefore, the weather-related negative pre-tax income impact on gas marketing services was limited to $9 million ($5 million after tax) and $4 million ($3 million after tax) for the successor year ended December 31, 2017 and the successor period of July 1, 2016 through December 31, 2016, respectively. There was no weather impact for the predecessor period of January 1, 2016 through June 30, 2016 or the predecessor year ended December 31, 2015.

The following table provides the number of customers served by the Company for the periods presented:

| | December 31, | | |
|---|---|---|---|
| | **2017** [(a)] | 2016 [(a)] | 2015 [(b)] |
| | *(in thousands, except market share %)* | | |
| Gas distribution operations | **4,623** | 4,586 | 4,526 |
| Gas marketing services | | | |
| Energy customers [(c)] | **774** | 656 | 645 |
| Market share of energy customers in Georgia | **29.2%** | 29.6% | 29.7% |
| Service contracts | **1,184** | 1,198 | 1,171 |

(a) Includes customer and contract counts at December 31, 2017 and 2016.
(b) Includes average customer and contract counts for the year ended December 31, 2015.
(c) Includes approximately 140,000 customers at December 31, 2017 that were contracted to serve beginning April 1, 2017.

The Company anticipates overall customer growth trends at gas distribution operations to continue as it expects continued improvement in the new housing market and low natural gas prices. The Company uses a variety of targeted marketing programs to attract new customers and to retain existing customers.

Gas marketing services' market share in Georgia decreased at December 31, 2017 compared to the two prior years as a result of a highly competitive marketing environment, which is expected to continue for the foreseeable future. The Company will continue efforts at gas marketing services to enter into targeted markets and expand its energy customers and service contracts.

### *Cost of Natural Gas and Other Sales*

Natural gas costs are the largest expense for the Company. Excluding Atlanta Gas Light, which does not sell natural gas to end-use customers, gas distribution operations charges its utility customers for natural gas consumed using natural gas cost recovery mechanisms set by the applicable state regulatory agencies. Under these mechanisms, all prudently-incurred natural gas costs are passed through to customers without markup, subject to regulatory review. Gas distribution operations defers or accrues the difference between the actual cost of natural gas and the amount of commodity revenue earned in a given period. The deferred or accrued amount is either billed or refunded to customers prospectively through adjustments to the commodity rate. Deferred natural gas costs are reflected as regulatory assets and accrued natural gas costs are reflected as regulatory liabilities. Therefore, gas costs recovered through natural gas revenues generally equal the amount expensed in cost of natural gas and do not affect net income from gas distribution operations. Cost of natural gas at gas distribution operations represented 79.6% of total cost of natural gas for 2017.

Gas marketing services customers are charged for actual or estimated natural gas consumed. Cost of natural gas includes the cost of fuel, lost and unaccounted for gas, adjustments to reduce the value of inventories to market value, and gains and losses associated with certain derivatives.

Cost of natural gas was $1.6 billion for the successor year ended December 31, 2017 , which reflected an increase in natural gas pricing of 26.3% during the year compared to 2016, partially offset by lower demand for natural gas.

For the successor period of July 1, 2016 through December 31, 2016 , cost of natural gas was $613 million and reflected low demand for natural gas driven by warm weather in the fourth quarter 2016.

Cost of natural gas was $755 million and $1.6 billion for the predecessor period of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, respectively, and reflected low demand for natural gas driven by warm weather during those periods.

The following table details the volumes of natural gas sold during all periods presented.

| | **Year Ended December 31,** | | | **2017 vs. 2016** | 2016 vs. 2015 |
|---|---|---|---|---|---|
| | **2017** | 2016 | 2015 | **% Change** | % Change |
| Gas distribution operations *(mmBtu in millions)* | | | | | |
| Firm | **667** | 670 | 695 | **(0.4)%** | (3.6)% |
| Interruptible | **95** | 96 | 99 | **(1.0)%** | (3.0)% |
| Total | **762** | 766 | 794 | **(0.5)%** | (3.5)% |
| Gas marketing services *(mmBtu in millions)* | | | | | |
| Firm: | | | | | |
| Georgia | **23** | 34 | 35 | **(32.4)%** | (2.9)% |
| Illinois | **8** | 12 | 13 | **(33.3)%** | (7.7)% |
| Other emerging markets | **15** | 12 | 11 | **25.0 %** | 9.1 % |
| Interruptible large commercial and industrial | **11** | 14 | 14 | **(21.4)%** | — % |
| Total | **57** | 72 | 73 | **(20.8)%** | (1.4)% |
| Wholesale gas services | | | | | |
| Daily physical sales *(mmBtu in millions/day)* | **6.4** | 7.4 | 6.8 | **(13.5)%** | 8.8 % |

### *Other Operations and Maintenance Expenses*

For the successor year ended December 31, 2017 , other operations and maintenance expenses were $940 million and primarily reflected compensation and benefit costs and professional services, including pipeline compliance and maintenance and legal services.

For the successor period of July 1, 2016 through December 31, 2016, other operations and maintenance expenses were $482 million and primarily reflected compensation and benefit costs and professional services, including pipeline compliance and maintenance and legal services.

For the predecessor period of January 1, 2016 through June 30, 2016 , other operations and maintenance expenses were $454 million consistent with the level of expenses in the corresponding period in 2015.

For the predecessor year ended December 31, 2015, other operations and maintenance expenses were $928 million and included pipeline compliance and maintenance costs, compensation and benefit costs, and a $14 million goodwill impairment charge. See ACCOUNTING POLICIES – "Assessment of Assets" herein and Note 1 to the financial statements under "Goodwill and Other Intangible Assets and Liabilities" for additional information on the goodwill impairment charge.

***Depreciation and Amortization***

For the successor year ended December 31, 2017 , depreciation and amortization was $501 million and included $38 million of additional amortization of intangible assets as a result of fair value adjustments in acquisition accounting, primarily at gas marketing services and $28 million in additional depreciation at gas distribution operations, primarily due to continued investment in infrastructure programs.

For the successor period of July 1, 2016 through December 31, 2016, depreciation and amortization was $238 million and included $23 million of additional amortization of intangible assets as a result of fair value adjustments in acquisition accounting, primarily at gas marketing services, as well as depreciation at gas distribution operations due to continued investment in infrastructure programs.

For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 , depreciation and amortization was $206 million and $397 million , respectively, and reflected depreciation related to additional assets placed in service at gas distribution operations due to continued investment in infrastructure programs.

See Notes 3 and 11 to the financial statements under " Regulatory Matters – Regulatory Infrastructure Programs" and "Merger with Southern Company," respectively, for additional information on infrastructure programs and the application of acquisition accounting.

***Taxes Other Than Income Taxes***

For the successor year ended December 31, 2017 , taxes other than income taxes were $184 million , which consisted primarily of revenue tax expenses, property taxes, and payroll taxes.

For the successor period of July 1, 2016 through December 31, 2016 , taxes other than income taxes were $71 million , which consisted primarily of revenue tax expenses, property taxes, and payroll taxes.

For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 , taxes other than income taxes were $99 million and $181 million , respectively, which consisted primarily of revenue tax expenses, property taxes, and payroll taxes.

***Merger-Related Expenses***

There were no Merger-related expenses in the successor year ended December 31, 2017 .

For the successor period of July 1, 2016 through December 31, 2016 , Merger-related expenses were $41 million , including $18 million in rate credits provided to the customers of Elizabethtown Gas and Elkton Gas as conditions of the Merger, $20 million for additional compensation-related expenses, and $3 million for financial advisory fees, legal expenses, and other Merger-related costs.

For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, Merger-related expenses were $56 million and $44 million , respectively, including $31 million and $20 million, respectively, for financial advisory fees, legal expenses, and other Merger-related costs, and $25 million and $24 million, respectively, for additional compensation-related expenses.

See Note 11 to the financial statements under "Merger with Southern Company" for additional information.

***Earnings from Equity Method Investments***

For the successor year ended December 31, 2017 , earnings from equity method investments were $106 million , reflecting $88 million in earnings from the Company's investment in SNG, including $33 million related to a non-cash charge recorded by SNG to establish a regulatory liability associated with the Tax Reform Legislation, and $18 million in earnings from all other investments.

For the successor period of July 1, 2016 through December 31, 2016 , earnings from equity method investments were $60 million , reflecting $56 million in earnings from the Company's investment in SNG and $4 million in earnings from all other investments.

For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, earnings from equity method investments were not material.

See Notes 4 and 11 to the financial statements under "Equity Method Investments" and "Investment in SNG," respectively, for additional information on the Company's investment in SNG.

***Interest Expense, Net of Amounts Capitalized***

For the successor year ended December 31, 2017 , interest expense, net of amounts capitalized was $200 million , which includes the $38 million fair value adjustment on long-term debt in acquisition accounting. Interest expense also reflects debt issuances and redemptions during the period and the recognition of previously deferred interest related to regulatory infrastructure programs.

For the successor period of July 1, 2016 through December 31, 2016 , interest expense, net of amounts capitalized was $81 million , which includes the $19 million fair value adjustment on long-term debt in acquisition accounting. Interest expense also reflects debt issuances and redemptions during the period and the recognition of previously deferred interest related to regulatory infrastructure programs.

For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, interest expense, net of amounts capitalized was $96 million and $175 million , respectively, reflecting debt issuances and redemptions during the period and the recognition of previously deferred interest related to regulatory infrastructure programs.

See FUTURE EARNINGS POTENTIAL – "Unrecognized Ratemaking Amounts" herein for additional information on the unrecognized costs related to the infrastructure programs. Also see FINANCIAL CONDITION AND LIQUIDITY – "Financing Activities" herein and Note 6 to the financial statements for additional information on outstanding debt.

***Other Income (Expense), Net***

For the successor year ended December 31, 2017 , other income (expense), net was $39 million and primarily related to a $20 million gain from the settlement of contractor litigation claims, tax gross-up on contributions in aid of construction, and AFUDC. See Note 3 to the financial statements under "Regulatory Matters – PRP Settlement" for additional information on contractor litigation claims.

For the successor period of July 1, 2016 through December 31, 2016 , other income (expense), net was $14 million and primarily related to the tax gross-up of contributions in aid of construction received from customers.

For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, other income (expense), net was not material.

***Income Taxes***

For the successor year ended December 31, 2017 , income taxes were $367 million . The effective tax rate in 2017 reflects additional expense from the revaluation of deferred tax assets of $93 million associated with the Tax Reform Legislation and $37 million associated with State of Illinois income tax legislation enacted in the third quarter 2017 and new income tax apportionment factors in several states resulting from the Company's inclusion in the consolidated Southern Company state tax filings.

For the successor period of July 1, 2016 through December 31, 2016 , income taxes were $76 million . The effective tax rate during this period reflects certain nondeductible Merger-related charges.

For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, income taxes were $87 million and $213 million , respectively. The effective tax rate in both periods reflects certain nondeductible Merger-related expenses and other charges.

The effective tax rate for each period presented is consistent when adjusted for the additional expense recorded from the revaluation of deferred tax assets associated with the Tax Reform Legislation, the State of Illinois income tax legislation enacted in the third quarter 2017, the allocation of new income tax apportionment factors in several states resulting from the Company's inclusion in the consolidated Southern Company state tax filings in 2017, and the nondeductible Merger-related charges for each period in 2017, 2016, and 2015.

See FUTURE EARNINGS POTENTIAL – " Income Tax Matters " herein and Note 5 to the financial statements for additional information.

**Noncontrolling Interest**

Prior to the October 2016 acquisition of Piedmont's 15% interest in SouthStar, net income attributable to noncontrolling interest was recorded on the statements of income and totaled $14 million and $20 million in the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, respectively. See Note 4 to the financial statements under

"Variable Interest Entities" for additional information.

**Effects of Inflation**

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

**Performance and Non-GAAP Measures**

Prior to the Merger, the Company evaluated segment performance using EBIT, which includes operating income, earnings from equity method investments, and other income (expense), net. EBIT excludes interest expense, net of amounts capitalized and income taxes (benefit), which were evaluated on a consolidated basis for those periods. EBIT is used herein to discuss the results of the Company's segments for the predecessor periods, as EBIT was the primary measure of segment profit or loss for those periods. Subsequent to the Merger, the Company changed its segment performance measure from EBIT to net income to better align with the performance measure utilized by Southern Company. EBIT for the year ended December 31, 2017 and the period of July 1, 2016 through December 31, 2016 presented herein is considered a non-GAAP measure. The Company also discusses consolidated EBIT, which is considered a non-GAAP measure for all periods presented. The presentation of consolidated EBIT is believed to provide useful supplemental information regarding a consolidated measure of profit or loss. The Company further believes the presentation of segment EBIT for the year ended December 31, 2017 and the period of July 1, 2016 through December 31, 2016 is useful as it allows for a measure of comparability to other companies with different capital and legal structures, which accordingly may be subject to different interest rates and effective tax rates. The applicable reconciliations of net income to consolidated EBIT and segment EBIT are provided herein.

Adjusted operating margin is a non-GAAP measure that is calculated as operating revenues less cost of natural gas, cost of other sales, and revenue tax expense. Adjusted operating margin excludes other operations and maintenance expenses, depreciation and amortization, taxes other than income taxes, and Merger-related expenses, which are included in the calculation of operating income as calculated in accordance with GAAP and reflected in the statements of income. The presentation of adjusted operating margin is believed to provide useful information regarding the contribution resulting from customer growth at gas distribution operations since the cost of natural gas and revenue tax expense can vary significantly and are generally billed directly to customers. The Company further believes that utilizing adjusted operating margin at gas marketing services, wholesale gas services, and gas midstream operations allows it to focus on a direct measure of performance before overhead costs. The applicable reconciliation of operating income to adjusted operating margin is provided herein.

EBIT and adjusted operating margin should not be considered alternatives to, or more meaningful indicators of, the Company's operating performance than net income attributable to the Company or operating income as determined in accordance with GAAP. In addition, the Company's adjusted operating margin may not be comparable to similarly titled measures of other companies.

See RESULTS OF OPERATIONS herein for information on the Company's financial performance.

Reconciliations of operating income to adjusted operating margin and net income attributable to Southern Company Gas to EBIT are as follows:

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | **Year Ended December 31, 2017** | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | Year Ended December 31, 2015 |
| | *(in millions)* | | *(in millions)* | |
| **Operating Income** | **$ 665** | $ 197 | $ 321 | $ 746 |
| Other operating expenses [(a)] | **1,625** | 832 | 815 | 1,550 |
| Revenue tax expense [(b)] | **(98)** | (31) | (56) | (101) |
| **Adjusted Operating Margin** | **$ 2,192** | $ 998 | $ 1,080 | $ 2,195 |

(a) Includes other operations and maintenance, depreciation and amortization, taxes other than income taxes, and Merger-related expenses.
(b) Nicor Gas' revenue tax expenses, which are passed through directly to customers.

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | **Year Ended December 31, 2017** | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | Year Ended December 31, 2015 |
| | *(in millions)* | | *(in millions)* | |
| **Net Income Attributable to Southern Company Gas** | **$ 243** | $ 114 | $ 131 | $ 353 |
| Net income attributable to noncontrolling interest | **—** | — | 14 | 20 |
| Income taxes | **367** | 76 | 87 | 213 |
| Interest expense, net of amounts capitalized | **200** | 81 | 96 | 175 |
| **EBIT** | **$ 810** | $ 271 | $ 328 | $ 761 |

**Segment Information**

Adjusted operating margin, operating expenses, and the Company's primary performance metric for each segment are illustrated in the tables below.

| | Successor | | | | | |
|---|---|---|---|---|---|---|
| | **Year ended December 31, 2017** | | | July 1, 2016 through December 31, 2016 | | |
| | **Adjusted Operating Margin (*)** | **Operating Expenses (*)** | **Net Income** | Adjusted Operating Margin (*) | Operating Expenses (*) | Net Income |
| | *(in millions)* | | | *(in millions)* | | |
| Gas distribution operations | **$ 1,834** | **$ 1,184** | **$ 353** | $ 817 | $ 595 | $ 77 |
| Gas marketing services | **313** | **200** | **84** | 139 | 112 | 19 |
| Wholesale gas services | **5** | **56** | **(57)** | 24 | 26 | — |
| Gas midstream operations | **42** | **52** | **3** | 19 | 26 | 20 |
| All other | **10** | **47** | **(140)** | 3 | 46 | (2) |
| Intercompany eliminations | **(12)** | **(12)** | **—** | (4) | (4) | — |
| Consolidated | **$ 2,192** | **$ 1,527** | **$ 243** | $ 998 | $ 801 | $ 114 |

(*) Adjusted operating margin and operating expenses are adjusted for Nicor Gas revenue tax expenses, which are passed through directly to customers.

| | Predecessor | | | | | |
|---|---|---|---|---|---|---|
| | January 1, 2016 through June 30, 2016 | | | Year ended December 31, 2015 | | |
| | Adjusted Operating Margin (*) | Operating Expenses (*) | EBIT | Adjusted Operating Margin (*) | Operating Expenses (*) | EBIT |
| | *(in millions)* | | | *(in millions)* | | |
| Gas distribution operations | $ 911 | $ 560 | $ 353 | $ 1,657 | $ 1,086 | $ 581 |
| Gas marketing services | 190 | 81 | 109 | 317 | 165 | 152 |
| Wholesale gas services | (36) | 33 | (68) | 183 | 71 | 110 |
| Gas midstream operations | 15 | 24 | (6) | 36 | 62 | (23) |
| All other | 4 | 65 | (60) | 7 | 70 | (59) |
| Intercompany eliminations | (4) | (4) | — | (5) | (5) | — |
| Consolidated | $ 1,080 | $ 759 | $ 328 | $ 2,195 | $ 1,449 | $ 761 |

(*) Adjusted operating margin and operating expenses are adjusted for Nicor Gas revenue tax expenses, which are passed through directly to customers.

***Gas Distribution Operations***

Gas distribution operations is the largest component of the Company's business and is subject to regulation and oversight by agencies in each of the states it serves. These agencies approve natural gas rates designed to provide the Company with the opportunity to generate revenues to recover the cost of natural gas delivered to its customers and its fixed and variable costs, including depreciation, interest, maintenance, taxes, and overhead costs, and to earn a reasonable return on its investments.

With the exception of Atlanta Gas Light, the Company's second largest utility that operates in a deregulated natural gas market and has a straight-fixed-variable rate design that minimizes the variability of its revenues based on consumption, the earnings of the natural gas distribution utilities can be affected by customer consumption patterns that are a function of weather conditions, price levels for natural gas, and general economic conditions that may impact customers' ability to pay for natural gas consumed. The Company has various weather mechanisms, such as weather normalization mechanisms and weather derivative instruments, that limit its exposure to weather changes within typical ranges in its natural gas distribution utilities' service territories.

*Successor Year Ended December 31, 2017*

Net income of $353 million includes $1.8 billion in adjusted operating margin, $1.2 billion in operating expenses, and $34 million in other income (expense), net, which resulted in EBIT of $684 million . Net income also includes $153 million in interest expense, net of amounts capitalized and $178 million in income tax expense. Adjusted operating margin reflects $99 million in additional revenue from continued investment in infrastructure replacement programs and base rate increases at Atlanta Gas Light, Elizabethtown Gas, and Virginia Natural Gas. Adjusted operating margin was also affected by increased customer growth, partially offset by the negative impact of warmer-than-normal weather, net of hedging. Operating expenses reflect a $28 million increase in depreciation associated with additional assets placed in service, as well as benefit and compensation costs, legal expenses, and pipeline compliance and maintenance expenses. Other income (expense), net reflects a $20 million gain from the settlement of contractor litigation claims. Interest expense reflects the impact of intercompany promissory notes executed in December 2016 and the issuance of first mortgage bonds at Nicor Gas on August 10, 2017 and November 1, 2017. Income tax expense includes a $22 million benefit as a result of the Tax Reform Legislation.

See Note 3 to the financial statements under "Regulatory Matters – PRP Settlement" for additional information on contractor litigation claims. See FINANCIAL CONDITION AND LIQUIDITY – "Financing Activities" herein and Note 6 to the financial statements for additional information on debt issuances. See FUTURE EARNINGS POTENTIAL – " Income Tax Matters " herein and Note 5 to the financial statements for additional information.

*Successor Period of July 1, 2016 through December 31, 2016*

Net income of $77 million includes $817 million in adjusted operating margin, $595 million in operating expenses, and $11 million in other income (expense), net, resulting in EBIT of $233 million . Net income also includes $105 million in interest expense, net of amounts capitalized and $51 million in income tax expense. Adjusted operating margin reflects revenue from continued investment in infrastructure replacement programs, partially offset by the impact of warm weather, net of hedging. Operating expenses reflect the depreciation associated with additional assets placed in service, the related expenses associated with pipeline compliance and maintenance activities, and $18 million of rate credits provided to the customers of Elizabethtown Gas and Elkton Gas as conditions of the Merger. See Note 11 to the financial statements under "Merger with Southern Company" for additional information.

*Predecessor Period of January 1, 2016 through June 30, 2016*

EBIT of $353 million includes $911 million in adjusted operating margin, $560 million in operating expense, and $2 million in other income (expense), net. Adjusted operating margin reflects increased revenue from continued investment in infrastructure replacement programs and the impact of customer usage and growth, partially offset by the impact of warm weather, net of hedging. Operating expenses reflect the depreciation associated with additional assets placed in service.

*Predecessor Year Ended December 31, 2015*

EBIT of $581 million includes $1.7 billion in adjusted operating margin, $1.1 billion in operating expense, and $10 million in other income (expense), net. Adjusted operating margin reflects revenue from the continued investment in infrastructure replacement programs, the impact of customer usage and growth, and the impact of warm weather, net of hedging. Operating expenses reflect the depreciation associated with additional assets placed in service, as well as benefits and compensation costs.

***Gas Marketing Services***

Gas marketing services consists of several businesses that provide energy-related products and services to natural gas markets, including warranty sales. Gas marketing services is weather sensitive and uses a variety of hedging strategies, such as weather derivative instruments and other risk management tools, to partially mitigate potential weather impacts. Operating expenses primarily reflect employee costs, marketing, customer care, and bad debt expenses.

*Successor Year Ended December 31, 2017*

Net income of $84 million includes $313 million in adjusted operating margin and $200 million in operating expenses, which resulted in EBIT of $113 million . Net income also includes $5 million in interest expense, net of amounts capitalized and $24 million in income tax expense. Adjusted operating margin reflects a $9 million negative impact of warmer-than-normal weather, net of hedging, and $4 million in unrealized hedge losses, net of recoveries. Operating expenses includes $40 million in additional amortization of intangible assets established in the application of acquisition accounting. Income tax expense includes a $19 million benefit as a result of the Tax Reform Legislation. See FUTURE EARNINGS POTENTIAL – " Income Tax Matters " herein and Note 5 to the financial statements for additional information.

*Successor Period of July 1, 2016 through December 31, 2016*

Net income of $19 million includes $139 million in adjusted operating margin and $112 million in operating expenses, resulting in EBIT of $27 million . Net income also includes $1 million in interest expense, net of amounts capitalized and $7 million in income tax expense. Adjusted operating margin reflects a reduction of $5 million due to fair value adjustments to certain assets and liabilities in the application of acquisition accounting. Also reflected in adjusted operating margin are unrealized hedge gains and LOCOM adjustments. Operating expenses reflect $23 million in additional amortization of intangible assets, partially offset by a $2 million reduction in operations and maintenance expense due to fair value adjustments to certain assets and liabilities in the application of acquisition accounting. See Note 1 to the financial statements under "Natural Gas for Sale" for additional information on LOCOM adjustments and Note 11 to the financial statements for additional information on the Merger.

*Predecessor Period of January 1, 2016 through June 30, 2016*

EBIT of $109 million includes $190 million in adjusted operating margin and $81 million in operating expenses. Adjusted operating margin reflects $9 million in unrealized hedge gains. Operating expenses reflect lower bad debt, marketing, and depreciation and amortization, compared to the same period in the prior year. Earnings also include $14 million attributable to noncontrolling interest.

*Predecessor Year Ended December 31, 2015*

EBIT of $152 million includes $317 million in adjusted operating margin and $165 million in operating expenses. Adjusted operating margin reflects revenue from gas marketing and warranty sales, which were partially offset by the impact of warm weather, net of hedging. Operating expenses primarily reflect compensation and benefits costs. Earnings also include $20 million attributable to noncontrolling interest.

***Wholesale Gas Services***

Wholesale gas services is involved in asset management and optimization, storage, transportation, producer and peaking services, natural gas supply, natural gas services, and wholesale gas marketing. The Company has positioned the business to generate positive economic earnings on an annual basis even under low volatility market conditions that can result from a number of factors. When market price volatility increases, wholesale gas services is well positioned to capture significant value and generate stronger results. Wholesale gas services generated positive economic results for the successor year ended December 31, 2017, primarily reflecting lower volatility market conditions throughout the majority of 2017 and higher volatility along with the widening of locational and transportation spreads in December 2017 due to colder weather, as well as higher natural gas storage value resulting from higher natural gas prices.

*Successor Year Ended December 31, 2017*

Net loss of $57 million includes $5 million in adjusted operating margin, $56 million in operating expenses, and $1 million in other income (expense), net, which resulted in a loss before interest and taxes of $50 million . Also included are $7 million in interest expense, net of amounts capitalized. Adjusted operating margin reflects a decrease of $21 million due to fair value adjustments to certain assets and liabilities in the application of acquisition accounting. Also reflected in adjusted operating margin is revenue from commercial activity partially offset by mark-to-market losses. Income tax expense includes $21 million resulting from the revaluation of deferred income tax assets associated with the Tax Reform Legislation. See FUTURE EARNINGS POTENTIAL – " Income Tax Matters " herein and Note 5 to the financial statements for additional information on income taxes.

*Successor Period of July 1, 2016 through December 31, 2016*

Net income includes $24 million in adjusted operating margin, $26 million in operating expenses, and $2 million in other income (expense), net, resulting in no EBIT. Also included are $3 million in interest expense, net of amounts capitalized and $3 million in income tax benefit. Adjusted operating margin reflects a decrease of $5 million due to fair value adjustments to certain assets and liabilities in the application of acquisition accounting. Also reflected in adjusted operating margin are mark-to-market gains due to changes in natural gas prices in the fourth quarter 2016 and losses from commercial activity due to low volatility in natural gas prices and warm weather. Operating expenses reflect low incentive compensation expense due to low earnings.

*Predecessor Period of January 1, 2016 through June 30, 2016*

Loss before interest and taxes of $68 million includes $(36) million in adjusted operating margin, $33 million in operating expense, and $1 million in other income (expense), net. Adjusted operating margin reflects mark-to-market losses and LOCOM adjustments as a result of changes in natural gas prices and revenues from commercial activity driven by changes in price volatility. Operating expenses reflect lower incentive compensation expense as compared to the same period in the prior year due to lower earnings.

*Predecessor Year Ended December 31, 2015*

EBIT of $110 million includes $183 million in adjusted operating margin, $71 million in operating expenses, and $(2) million in other income (expense), net. Adjusted operating margin reflects revenue from commercial activity driven by changes in price volatility, mark-to-market gains, and LOCOM adjustments as a result of changes in natural gas prices.

The following table illustrates the components of wholesale gas services' adjusted operating margin for the periods presented:

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | **Year Ended December 31, 2017** | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | Year Ended December 31, 2015 |
| | *(in millions)* | | *(in millions)* | |
| Commercial activity recognized | **$ 116** | $ (15) | $ 34 | $ 140 |
| Gain (loss) on storage derivatives | **23** | (20) | (38) | 45 |
| Gain (loss) on transportation and forward commodity derivatives | **(113)** | 64 | (31) | 11 |
| LOCOM adjustments, net of current period recoveries | **—** | — | (1) | (13) |
| Purchase accounting adjustments to fair value inventory and contracts | **(21)** | (5) | — | — |
| Adjusted operating margin | **$ 5** | $ 24 | $ (36) | $ 183 |

*Change in Commercial Activity*

The commercial activity at wholesale gas services includes recognition of storage and transportation values that were generated in prior periods, which reflect the impact of prior period hedge gains and losses as associated physical transactions occur. Warmer-than-normal weather during the 2016/2017 Heating Season, lower power generation volumes, and build-out of new U.S. pipeline infrastructure, along with increases in natural gas supply, caused low volatility and a tightening of locational or transportation spreads throughout the majority of 2017, negatively impacting the amount of commercial activity revenues generated relative to demand fees for contracted pipeline transportation and storage capacity, and minimum sharing under asset management agreements. However, during December 2017, significantly colder weather increased natural gas price volatility and transportation spreads widened, enabling wholesale gas services to capture higher commercial activity. Further, as natural gas prices and forward storage or time spreads increased, wholesale gas services was able to capture higher storage values that it expects to recognize as commercial activity revenues when natural gas is physically withdrawn from storage.

*Change in Storage and Transportation Derivatives*

Volatility in the natural gas market arises from a number of factors, such as weather fluctuations or changes in supply or demand for natural gas in different regions of the U.S. The volatility of natural gas commodity prices has a significant impact on the Company's customer rates, long-term competitive position against other energy sources, and the ability of wholesale gas services to capture value from locational and seasonal spreads. Transportation and forward commodity derivative losses are primarily the result of widening transportation spreads during the fourth quarter 2017 due to significantly colder weather in the Northeast and Midwest U.S., which impacted forward prices at natural gas receipt and delivery points. Additionally, during 2017, forward storage or time spreads applicable to the locations of wholesale gas services' specific storage positions resulted in storage derivative gains.

The natural gas that the Company purchases and injects into storage is accounted for at the LOCOM value utilizing gas daily or spot prices at the end of the year. Wholesale gas services recorded LOCOM adjustments of $19 million for the predecessor year ended December 31, 2015. LOCOM adjustments for all other periods presented were immaterial. See Note 1 to the financial statements under "Natural Gas for Sale" for additional information.

*Withdrawal Schedule and Physical Transportation Transactions*

The expected natural gas withdrawals from storage and expected offset to prior hedge losses/gains associated with the transportation portfolio of wholesale gas services are presented in the following table, along with the net operating revenues expected at the time of withdrawal from storage and the physical flow of natural gas between contracted transportation receipt and delivery points. Wholesale gas services' expected net operating revenues exclude storage and transportation demand charges, as well as other variable fuel, withdrawal, receipt, and delivery charges, but are net of the estimated impact of profit sharing under its asset management agreements. Further, the amounts that are realizable in future periods are based on the inventory withdrawal schedule, planned physical flow of natural gas between the transportation receipt and delivery points, and forward natural gas prices at December 31, 2017. A portion of wholesale gas services' storage inventory and transportation capacity is economically hedged with futures contracts, which results in the realization of substantially fixed net operating revenues.

| | Storage Withdrawal | | |
|---|---|---|---|
| | **Total storage** (WACOG $2.66) | **Expected net operating gains** (a) | **Physical Transportation Transactions – Expected Net Operating Gains** (b) |
| | *(in mmBtu in millions)* | *(in millions)* | *(in millions)* |
| 2018 | **55.2** | **$ 14** | **$ 70** |
| 2019 and thereafter | **2.3** | **1** | **43** |
| Total at December 31, 2017 | **57.5** | **$ 15** | **$ 113** |

(a) Represents expected operating gains from planned storage withdrawals associated with existing inventory positions and could change as wholesale gas services adjusts its daily injection and withdrawal plans in response to changes in future market conditions and forward NYMEX price fluctuations. Also includes the impact of purchase accounting adjustments to reflect natural gas storage inventory at market value. Excluding the impact of these adjustments, the expected net operating gains at December 31, 2017 would have been $22 million.

(b) Represents the periods associated with the transportation derivative (gains) and losses during which the derivatives will be settled and the physical transportation transactions will occur that offset the derivative losses that were previously recognized.

***Gas Midstream Operations***

Gas midstream operations consists primarily of gas pipeline investments, with storage and fuels also aggregated into this segment. Gas pipeline investments include SNG, Horizon Pipeline, Atlantic Coast Pipeline, PennEast Pipeline, Dalton Pipeline, and Magnolia Enterprise Holdings, Inc. See Note 4 to the financial statements under "Equity Method Investments" for additional information.

*Successor Year Ended December 31, 2017*

Net income of $3 million includes $42 million in adjusted operating margin, $52 million in operating expenses, $103 million in earnings from equity method investments, consisting primarily of the Company's equity interest in SNG, including $33 million related to a non-cash charge recorded by SNG to establish a regulatory liability associated with the Tax Reform Legislation, and $4 million in other income, which resulted in EBIT of $97 million . Also included in net income are $33 million in interest expense, net of amounts capitalized and $61 million in income tax expense. Income tax expense includes $27 million resulting from the revaluation of deferred income tax assets associated with the Tax Reform Legislation and $8 million related to the allocation of new income tax apportionment factors in several states resulting from the Company's inclusion in the consolidated Southern Company state tax filings. See FUTURE EARNINGS POTENTIAL – " Income Tax Matters " herein and Note 5 to the financial statements for additional information on income taxes.

*Successor Period of July 1, 2016 through December 31, 2016*

Net income of $20 million includes $19 million in adjusted operating margin, $26 million in operating expenses, $58 million in earnings from equity method investments, consisting primarily of the Company's September 2016 acquired equity interest in SNG, and $1 million in other income, resulting in EBIT of $52 million. Also included in net income are $16 million in interest expense, net of amounts capitalized and $16 million in income tax expense.

*Predecessor Periods of January 1, 2016 through June 30, 2016 and the Year Ended December 31, 2015*

Loss before interest and taxes for the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 were $6 million and $23 million , respectively, and reflected a $14 million goodwill impairment charge in 2015.

***All Other***

All other includes the Company's investment in Triton, AGL Services Company, and Southern Company Gas Capital, as well as various corporate operating expenses that are not allocated to the reportable segments and interest income (expense) associated with affiliate financing arrangements.

*Successor Year Ended December 31, 2017*

Net loss of $140 million includes $10 million in adjusted operating margin and $47 million in operating expenses. Operating expenses included $26 million of integration-related costs. Interest expense, net of amounts capitalized was $2 million due to the intercompany promissory notes that were executed in December 2016. Income tax expense was $104 million and includes $86 million resulting from the revaluation of deferred tax assets associated with the Tax Reform Legislation and $29 million associated with State of Illinois tax legislation enacted during the third quarter 2017 and new income tax apportionment factors in several states resulting from the Company's inclusion in the consolidated Southern Company state tax filings. See FINANCIAL CONDITION AND LIQUIDITY – "Financing Activities" herein for additional financing information and FUTURE EARNINGS POTENTIAL – " Income Tax Matters " herein and Note 5 to the financial statements for additional information on income taxes.

*Successor Period of July 1, 2016 through December 31, 2016*

Operating expenses included Merger-related expenses of $41 million primarily comprised of compensation-related expenses, financial advisory fees, legal expenses, and other Merger-related costs and $8 million in expenses associated with certain benefit arrangements.

*Predecessor Periods of January 1, 2016 through June 30, 2016 and the Year Ended December 31, 2015*

For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, operating expenses included Merger-related expenses of $56 million and $44 million , respectively. These expenses are primarily comprised of financial advisory and legal expenses as well as additional compensation-related expenses, including acceleration of share-based compensation expenses, and change-in-control compensation charges. See Note 11 to the financial statements under "Merger with Southern Company" for additional information.

**Segment Reconciliations**

Reconciliations of net income attributable to Southern Company Gas to EBIT for the year ended December 31, 2017 and the period of July 1, 2016 through December 31, 2016, and operating income to adjusted operating margin for all periods presented, are in the following tables. See Note 12 to the financial statements for additional segment information.

| | Successor | | | | | | |
|---|---|---|---|---|---|---|---|
| | Year Ended December 31, 2017 | | | | | | |
| | Gas Distribution Operations | Gas Marketing Services | Wholesale Gas Services | Gas Midstream Operations | All Other | Intercompany Elimination | Consolidated |
| | *(in millions)* | | | | | | |
| **Net Income (Loss) Attributable to Southern Company Gas** | **$ 353** | **$ 84** | **$ (57)** | **$ 3** | **$ (140)** | **$ —** | **$ 243** |
| Income taxes | **178** | **24** | **—** | **61** | **104** | **—** | **367** |
| Interest expense, net of amounts capitalized | **153** | **5** | **7** | **33** | **2** | **—** | **200** |
| **EBIT** | **$ 684** | **$ 113** | **$ (50)** | **$ 97** | **$ (34)** | **$ —** | **$ 810** |

**MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)**
**Southern Company Gas and Subsidiary Companies 2017 Annual Report**

| | Successor | | | | | | |
|---|---|---|---|---|---|---|---|
| | July 1, 2016 through December 31, 2016 | | | | | | |
| | Gas Distribution Operations | Gas Marketing Services | Wholesale Gas Services | Gas Midstream Operations | All Other | Intercompany Elimination | Consolidated |
| | *(in millions)* | | | | | | |
| **Net Income (Loss) Attributable to Southern Company Gas** | $ 77 | $ 19 | $ — | $ 20 | $ (2) | $ — | $ 114 |
| Income taxes (benefit) | 51 | 7 | (3) | 16 | 5 | — | 76 |
| Interest expense, net of amounts capitalized | 105 | 1 | 3 | 16 | (44) | — | 81 |
| **EBIT** | $ 233 | $ 27 | $ — | $ 52 | $ (41) | $ — | $ 271 |

| | **Successor** | | | | | | |
|---|---|---|---|---|---|---|---|
| | **Year Ended December 31, 2017** | | | | | | |
| | **Gas Distribution Operations** | **Gas Marketing Services** | **Wholesale Gas Services** | **Gas Midstream Operations** | **All Other** | **Intercompany Elimination** | **Consolidated** |
| | *(in millions)* | | | | | | |
| **Operating Income (Loss)** | **$ 650** | **$ 113** | **$ (51)** | **$ (10)** | **$ (37)** | **$ —** | **$ 665** |
| Other operating expenses [(a)] | **1,282** | **200** | **56** | **52** | **47** | **(12)** | **1,625** |
| Revenue tax expense [(b)] | **(98)** | **—** | **—** | **—** | **—** | **—** | **(98)** |
| **Adjusted Operating Margin** | **$ 1,834** | **$ 313** | **$ 5** | **$ 42** | **$ 10** | **$ (12)** | **$ 2,192** |

| | Successor | | | | | | |
|---|---|---|---|---|---|---|---|
| | July 1, 2016 through December 31, 2016 | | | | | | |
| | Gas Distribution Operations | Gas Marketing Services | Wholesale Gas Services | Gas Midstream Operations | All Other | Intercompany Elimination | Consolidated |
| | *(in millions)* | | | | | | |
| **Operating Income (Loss)** | $ 222 | $ 27 | $ (2) | $ (7) | $ (43) | $ — | $ 197 |
| Other operating expenses [(a)] | 626 | 112 | 26 | 26 | 46 | (4) | 832 |
| Revenue tax expense [(b)] | (31) | — | — | — | — | — | (31) |
| **Adjusted Operating Margin** | $ 817 | $ 139 | $ 24 | $ 19 | $ 3 | $ (4) | $ 998 |

| | Predecessor | | | | | | |
|---|---|---|---|---|---|---|---|
| | January 1, 2016 through June 30, 2016 | | | | | | |
| | Gas Distribution Operations | Gas Marketing Services | Wholesale Gas Services | Gas Midstream Operations | All Other | Intercompany Elimination | Consolidated |
| | *(in millions)* | | | | | | |
| **Operating Income (Loss)** | $ 351 | $ 109 | $ (69) | $ (9) | $ (61) | $ — | $ 321 |
| Other operating expenses [(a)] | 616 | 81 | 33 | 24 | 65 | (4) | 815 |
| Revenue tax expense [(b)] | (56) | — | — | — | — | — | (56) |
| **Adjusted Operating Margin** | $ 911 | $ 190 | $ (36) | $ 15 | $ 4 | $ (4) | $ 1,080 |

| | Predecessor | | | | | | |
|---|---|---|---|---|---|---|---|
| | Year Ended December 31, 2015 | | | | | | |
| | Gas Distribution Operations | Gas Marketing Services | Wholesale Gas Services | Gas Midstream Operations | All Other | Intercompany Elimination | Consolidated |
| | *(in millions)* | | | | | | |
| **Operating Income (Loss)** | $ 571 | $ 152 | $ 112 | $ (26) | $ (63) | $ — | $ 746 |
| Other operating expenses [(a)] | 1,187 | 165 | 71 | 62 | 70 | (5) | 1,550 |
| Revenue tax expense [(b)] | (101) | — | — | — | — | — | (101) |
| **Adjusted Operating Margin** | $ 1,657 | $ 317 | $ 183 | $ 36 | $ 7 | $ (5) | $ 2,195 |

(a) Includes other operations and maintenance, depreciation and amortization, taxes other than income taxes, goodwill impairment in 2015, and Merger-related expenses.

(b) Nicor Gas' revenue tax expenses, which are passed through directly to customers.

## FUTURE EARNINGS POTENTIAL

### General

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's primary business of natural gas distribution and its complementary businesses in the gas marketing services, wholesale gas services, and gas midstream operations sectors. These factors include the Company's ability to maintain a constructive regulatory environment that allows for the timely recovery of prudently-incurred costs, the completion and subsequent operation of ongoing infrastructure and other construction projects, creditworthiness of customers, the Company's ability to optimize its transportation and storage positions, and its ability to re-contract storage rates at favorable prices.

Future earnings will be driven primarily by customer growth and are subject to a variety of other factors. These factors include weather, competition, new energy contracts with other utilities and other wholesale customers, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of natural gas, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territories. Demand for natural gas is primarily driven by the pace of economic growth that may be affected by changes in regional and global economic conditions, which may impact future earnings.

Volatility of natural gas prices has a significant impact on the Company's customer rates, long-term competitive position against other energy sources, and the ability of its gas marketing services and wholesale gas services segments to capture value from locational and seasonal spreads. Additionally, changes in commodity prices subject a significant portion of the Company's operations to earnings variability. Over the longer term, volatility is expected to be low to moderate and locational and/or transportation spreads are expected to decrease as new pipelines are built to reduce the existing supply constraints in the shale areas of the Northeast U.S. To the extent these pipelines are delayed or not built, volatility could increase. Additional economic factors may contribute to this environment, including a significant drop in oil and natural gas prices, which could lead to consolidation of natural gas producers or reduced levels of natural gas production. Further, if economic conditions continue to improve, including the new housing market, the demand for natural gas may increase, which may cause natural gas prices to rise and drive higher volatility in the natural gas markets on a longer-term basis.

On December 22, 2017, the Tax Reform Legislation was signed into law and became effective on January 1, 2018, which among other things, reduces the federal corporate income tax rate to 21% and changes rates of depreciation and the business interest deduction. On July 6, 2017, the State of Illinois enacted tax legislation that repealed its non-combination tax rule and increased the effective corporate income tax rate effective July 1, 2017. In addition, Southern Company calculated new apportionment factors in several states to include the Company in its consolidated tax filings. See " Income Tax Matters " and FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein and Notes 3 and 5 to the financial statements for additional information.

As part of its business strategy, the Company regularly considers and evaluates joint development arrangements as well as acquisitions and dispositions of businesses and assets. On October 15, 2017, the Company's subsidiary Pivotal Utility Holdings entered into agreements for the sale of the assets of two of its natural gas distribution utilities, Elizabethtown Gas and Elkton Gas, to South Jersey Industries, Inc.; the asset sales are expected to be completed by the end of the third quarter 2018. Net income attributable to Elizabethtown Gas and Elkton Gas for the year ended December 31, 2017 was $34 million. However, due to the seasonal nature of the natural gas business and other factors including, but not limited to, weather, regulation, competition, customer demand, and general economic conditions, the 2017 net income is not necessarily indicative of the results to be expected for any other period. See BUSINESS – "Seasonality" in Item 1, RISK FACTORS in Item 1A, and Note 11 to the financial statements under "Proposed Sale of Elizabethtown Gas and Elkton Gas" for additional information.

**Environmental Matters**

The Company's operations are regulated by state and federal environmental agencies through a variety of laws and regulations governing air, water, land, and protection of other natural resources. The Company maintains a comprehensive environmental compliance strategy to assess upcoming requirements and compliance costs associated with these environmental laws and regulations. The costs, including capital expenditures and operations and maintenance costs, required to comply with environmental laws and regulations may impact future results of operations, cash flows, and financial condition. A major portion of these compliance costs are expected to be recovered through existing ratemaking provisions. The ultimate impact of the environmental laws and regulations discussed below will depend on various factors, such as state adoption and implementation of requirements and the outcome of pending and/or future legal challenges.

New or revised environmental laws and regulations could affect many areas of the Company's operations. The impact of any such changes cannot be determined at this time. Environmental compliance costs could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis . Further, increased costs that are recovered through regulated rates could contribute to reduced demand for natural gas , which could negatively affect results of operations, cash flows, and financial condition. Additionally, many commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for natural gas . See Note 3 to the financial statements under "Environmental Matters" for additional information.

***Environmental Remediation***

The Company is subject to environmental remediation liabilities associated with 46 former MGP sites in five different states. The Company conducts studies to determine the extent of any required cleanup and has recognized the costs to clean up known impacted sites in its financial statements. Accrued environmental remediation costs totaling $388 million were included in the balance sheets at December 31, 2017 , $46 million of which is expected to be incurred over the next 12 months. The natural gas distribution utilities in Illinois, New Jersey, Georgia, and Florida have all received authority from their respective state regulators to recover approved environmental compliance costs through regulatory mechanisms, which covers substantially all of the total accrued remediation costs. See FINANCIAL CONDITION AND LIQUIDITY – " Capital Requirements and Contractual Obligations " herein for additional information.

***Water Quality***

In 2015, the EPA and the U.S. Army Corps of Engineers (Corps) jointly published a final rule that revised the regulatory definition of waters of the United States (WOTUS) for all Clean Water Act programs. The rule significantly expanded the scope of federal jurisdiction over waterbodies (such as rivers, streams, and canals), which could impact permitting and reporting requirements associated with the installation, expansion, and maintenance of pipeline projects. On July 27, 2017, the EPA and the Corps proposed to rescind the 2015 WOTUS rule. The WOTUS rule has been stayed by the U.S. Court of Appeals for the Sixth Circuit since late 2015, but on January 22, 2018, the U.S. Supreme Court determined that federal district courts have jurisdiction over the pending challenges to the rule. On February 6, 2018, the EPA and the Corps published a final rule delaying implementation of the 2015 WOTUS rule to 2020.

**FERC Matters**

The Company is involved in two significant pipeline construction projects within gas midstream operations. These projects, along with the Company's existing pipelines, are intended to provide diverse sources of natural gas supplies to customers, resolve current and long-term supply planning for new capacity, enhance system reliability, and generate economic development in the areas served. The following table provides an overview of these pipeline projects.

| | Miles of Pipe | Capital Expenditures | Ownership Interest |
|---|---|---|---|
| | | *(in millions)* | |
| Atlantic Coast Pipeline [(a)(b)] | 594 | $ 310 | 5% |
| PennEast Pipeline [(a)(c)] | 118 | 276 | 20% |
| Total | 712 | $ 586 | |

(a) Represents the Company's expected capital expenditures and ownership interest, which may change.

(b) In 2014, the Company entered into a joint venture to construct and operate a natural gas pipeline that will run from West Virginia through Virginia and into eastern North Carolina to meet the region's growing demand for natural gas. The proposed pipeline project is expected to transport natural gas to customers in Virginia. On October 13, 2017, the Atlantic Coast Pipeline project received FERC approval. The joint venture continues to work with state and other federal agencies to obtain the required environmental permits to begin construction.

(c) In 2014, the Company entered into a joint venture to construct and operate a natural gas pipeline that will transport low-cost natural gas from the Marcellus Shale area to customers in New Jersey. The Company believes this will alleviate takeaway constraints in the Marcellus region and help mitigate some of the price volatility experienced during recent winters. On January 19, 2018, the PennEast Pipeline project received FERC approval. The joint venture continues to work with state and other federal agencies to obtain the required environmental permits to begin construction.

On August 1, 2017, the Dalton Pipeline, which serves as an extension of the Transco pipeline system and provides additional natural gas supply to customers in Georgia, was placed in service. The Company has a 50% ownership interest in the Dalton Pipeline. See Note 4 to the financial statements for additional information.

On January 16, 2018, the Georgia PSC approved SNG's purchase of Georgia Power Company's natural gas lateral pipeline serving Plant McDonough Units 4 through 6 at net book value. Pursuant to this approval, legal transfer of the lateral pipeline is expected to occur in the fourth quarter 2018 and payment of $142 million is expected to occur in the first quarter 2020. During this interim period, Georgia Power Company will receive a discounted shipping rate to reflect the delayed consideration. Completion of this sale is contingent on certain conditions being satisfied by SNG that include, among other things, expansion of the existing lateral pipeline. The Company's portion of the expected capital expenditures for this project is $120 million. On February 15, 2018, FERC approval was obtained. The ultimate outcome of this matter cannot be determined at this time.

**Regulatory Matters**

***Utility Regulation and Rate Design***

The natural gas distribution utilities are subject to regulations and oversight by their respective state regulatory agencies for the rates charged to their customers, maintenance of accounting records, and various service and safety matters. Rates charged to customers vary according to customer class (residential, commercial, or industrial) and rate jurisdiction. These agencies approve rates designed to provide the opportunity to generate revenues to recover all prudently-incurred costs, including a return on rate base sufficient to pay interest on debt and provide a reasonable ROE. Rate base generally consists of the original cost of the utility plant in service, working capital, and certain other assets, less accumulated depreciation on the utility plant in service and net deferred income tax liabilities, and may include certain other additions or deductions.

The natural gas market for Atlanta Gas Light was deregulated in 1997. Accordingly, Marketers, rather than a traditional utility, sell natural gas to end-use customers in Georgia and handle customer billing functions. The Marketers file their rates monthly with the Georgia PSC. As a result of operating in a deregulated environment, Atlanta Gas Light's role includes:

- distributing natural gas for Marketers;
- constructing, operating, and maintaining the gas system infrastructure, including responding to customer service calls and leaks;
- reading meters and maintaining underlying customer premise information for Marketers; and
- planning and contracting for capacity on interstate transportation and storage systems.

Atlanta Gas Light earns revenue by charging rates to its customers based primarily on monthly fixed charges that are set by the Georgia PSC and adjusted periodically. The Marketers add these fixed charges when billing customers. This mechanism, called a straight-fixed-variable rate design, minimizes the seasonality of Atlanta Gas Light's revenues since the monthly fixed charge is not volumetric or directly weather dependent.

With the exception of Atlanta Gas Light, the earnings of the natural gas distribution utilities can be affected by customer consumption patterns that are largely a function of weather conditions and price levels for natural gas. Specifically, customer demand substantially increases during the Heating Season when natural gas is used for heating purposes. The Company has various mechanisms, such as weather normalization mechanisms and weather derivative instruments, at most of its utilities that limit exposure to weather changes within typical ranges in these utilities' respective service territories.

With the exception of Atlanta Gas Light, the natural gas distribution utilities are authorized by the relevant regulatory agencies in the states in which they serve to use natural gas cost recovery mechanisms that adjust rates to reflect changes in the wholesale cost of natural gas and ensure recovery of all costs prudently incurred in purchasing natural gas for customers. Since Atlanta Gas Light does not sell natural gas directly to its end-use customers, it does not utilize a traditional natural gas cost recovery mechanism. However, Atlanta Gas Light does maintain natural gas inventory for the Marketers in Georgia and recovers the cost through recovery mechanisms approved by the Georgia PSC specific to Georgia's deregulated market. In addition to natural gas recovery mechanisms, there are other cost recovery mechanisms, such as regulatory riders, which vary by utility but allow recovery of certain costs, such as those related to infrastructure replacement programs as well as environmental remediation and energy efficiency plans. In traditional rate designs, utilities recover a significant portion of the fixed customer service and pipeline infrastructure costs based on assumed natural gas volumes used by customers. Three of the utilities have decoupled regulatory mechanisms that the Company believes encourage conservation by separating the recoverable amount of these fixed costs from the amounts of natural gas used by customers. Natural gas cost recovery revenues are adjusted for differences in actual recoverable natural gas costs and amounts billed in current regulated rates. Changes in the billing factor will not have a significant effect on the Company's revenues or net income, but will affect cash flows. See Note 3 to the financial statements under " Regulatory Matters " for additional information.

The following table provides regulatory information for the Company's six largest natural gas distribution utilities:

| | Nicor Gas | Atlanta Gas Light | Elizabethtown Gas | Virginia Natural Gas | Florida City Gas | Chattanooga Gas |
|---|---|---|---|---|---|---|
| Authorized ROE [(a)(b)] | 9.80% | 10.75% | 9.60% | 9.50% | 11.25% | 10.05% |
| Weather normalization [(c)] | | | ✓ | ✓ | | ✓ |
| Decoupled, including straight-fixed-variable rates [(d)] | | ✓ | | ✓ | | ✓ |
| Regulatory infrastructure program rates [(e)] | ✓ | | | ✓ | ✓ | |
| Bad debt rider [(f)] | ✓ | | | ✓ | | ✓ |
| Energy efficiency plan [(g)] | ✓ | | ✓ | ✓ | ✓ | ✓ |
| Last decision on change in rates [(h)] | 2018 | 2017 | 2017 | 2017 | 2004 | 2010 |

(a) Represents the authorized ROE, or the midpoint of the authorized ROE range, at December 31, 2017 , except Nicor Gas which represents the authorized ROE established in the January 31, 2018 order issued by the Illinois Commission. The authorized ROE of Nicor Gas at December 31, 2017 was 10.17%. See "Base Rate Cases" herein and Note 3 to the financial statements under "Regulatory Matters – Base Rate Cases" for additional information.

(b) The authorized ROE range for Atlanta Gas Light, Virginia Natural Gas, and Florida City Gas was 10.55% - 10.95%, 9.00% - 10.00%, and 10.25% - 12.25%, respectively, at December 31, 2017 .

(c) Regulatory mechanisms that allow recovery of costs in the event of unseasonal weather, but are not direct offsets to the potential impacts on earnings of weather and customer consumption. These mechanisms are designed to help stabilize operating results by increasing base rate amounts charged to customers when weather is warmer than normal and decreasing amounts charged when weather is colder than normal.

(d) Recovery of fixed customer service costs separately from assumed natural gas volumes used by customers.

(e) Programs that update or expand distribution systems and LNG facilities.

(f) The recovery (refund) of bad debt expense over (under) an established benchmark expense. Virginia Natural Gas and Chattanooga Gas recover the gas portion of bad debt expense through their purchased gas adjustment mechanisms.

(g) Recovery of costs associated with plans to achieve specified energy savings goals.

(h) See "Base Rate Cases" herein and Note 3 to the financial statements under "Regulatory Matters – Base Rate Cases" for additional information.

### *Infrastructure Replacement Programs and Capital Projects*

The Company continues to focus on capital discipline and cost control while pursuing projects and initiatives that are expected to have current and future benefits to customers, provide an appropriate return on invested capital, and help ensure the safety and reliability of the utility infrastructure. Total capital expenditures incurred during 2017 for gas distribution operations were $1.3 billion . The following table and discussions provide updates on the infrastructure replacement programs at the natural gas distribution utilities, which are designed to update or expand the Company's distribution systems to improve reliability and meet operational flexibility and growth. The anticipated expenditures for these programs in 2018 are quantified in the discussion below.

| Utility | Program | Program Details | Recovery | Expenditures in 2017 | Expenditures Since Project Inception | Miles of Pipe Installed Since Project Inception | Scope of Program | Program Duration | Last Year of Program |
|---|---|---|---|---|---|---|---|---|---|
| | | | | *(in millions)* | | | *(miles)* | *(years)* | |
| Nicor Gas | Investing in Illinois | (a)(b) | Rider | $ 336 | $ 907 | 516 | 800 | 9 | 2023 |
| Atlanta Gas Light | Integrated Vintage Plastic Replacement Program (i-VPR) | (c)(i) | Base Rates | 50 | 251 | 782 | 756 | 4 | 2017 |
| Atlanta Gas Light | Integrated System Reinforcement Program (i-SRP) | (g)(i) | Base Rates | 76 | 446 | n/a | n/a | 8 | 2017 |
| Atlanta Gas Light | Integrated Customer Growth Program (i-CGP) | (h)(i) | Base Rates | 18 | 89 | n/a | n/a | 8 | 2017 |
| Chattanooga Gas | Bare Steel & Cast Iron | (e) | Base Rates | 3 | 43 | 94 | 111 | 10 | 2020 |
| Florida City Gas | Safety, Access and Facility Enhancement Program (SAFE) | (d) | Rider | 10 | 21 | 64 | 250 | 10 | 2025 |
| Florida City Gas | Galvanized Replacement Program | (f) | Base Rates | — | 16 | 80 | 111 | 17 | 2017 |
| Virginia Natural Gas | Steps to Advance Virginia's Energy (SAVE and SAVE II) | (a) | Rider | 34 | 156 | 255 | 496 | 10 | 2021 |
| Elizabethtown Gas | Aging Infrastructure Replacement (AIR) | (e) | Base Rates | 16 | 115 | 96 | 130 | 4 | 2017 |
| Total | | | | $ 543 | $ 2,044 | 1,887 | 2,654 | | |

(a) Replacement of cast iron, bare steel, mid-vintage plastic, and risk-based materials.
(b) Represents expenditures on qualifying infrastructure placed into service after December 9, 2014.
(c) Replacement of early vintage plastic, risk-based mid-vintage plastic, and mid-vintage neighborhood convenience.
(d) Replacement of four-inch and smaller mains, associated service lines, and in some instances above-ground facilities associated with rear-lot easements.
(e) Replacement of cast iron and bare steel pipes.
(f) Replacement of galvanized and X-Tube steel pipes. Reflects expenditures and miles of pipe installed since the Company acquired Florida City Gas in 2004.
(g) Installation of large diameter pressure improvement and system reinforcement projects.
(h) Installation of new business construction and strategic line extension.
(i) Recovery of the related program costs was incorporated in Atlanta Gas Light's petition for GRAM, which the Georgia PSC approved on February 21, 2017. See "Base Rate Cases" herein and Note 3 to the financial statements under "Regulatory Matters – Base Rate Cases" for additional information.

*Nicor Gas*

In 2013, Illinois enacted legislation that allows Nicor Gas to provide more widespread safety and reliability enhancements to its distribution system. The legislation stipulates that rate increases to customers as a result of any infrastructure investments shall not exceed a cumulative annual average of 4.0% or, in any given year, 5.5% of base rate revenues. In 2014, the Illinois

Commission approved the nine-year regulatory infrastructure program, Investing in Illinois, under which Nicor Gas implemented rates that became effective in March 2015. Nicor Gas expects to place into service $350 million of qualifying projects under Investing in Illinois in 2018 .

Investing in Illinois is subject to annual review by the Illinois Commission. In conjunction with the base rate case order issued by the Illinois Commission on January 31, 2018, Nicor Gas is recovering the portion of these program costs incurred prior to December 31, 2017 through base rates. See "Base Rate Cases" herein for additional information.

*Atlanta Gas Light*

Atlanta Gas Light's STRIDE program, which was initially approved by the Georgia PSC in 2009, is comprised of i-SRP, i-CGP, and i-VPR, and consists of infrastructure development, enhancement, and replacement programs that are used to update and expand distribution systems and LNG facilities, improve system reliability, and meet operational flexibility and growth. For 2017 and subsequent years, the recovery of and return on current and future capital investments under the STRIDE program are included in the annual base rate revenue adjustment under GRAM.

The i-CGP program authorized Atlanta Gas Light to spend $91 million through 2017 on projects to extend its pipeline facilities to serve customers in areas without pipeline access and create new economic development opportunities in Georgia. This program ended in 2017 and was replaced with a tariff to provide up to $15 million annually for Atlanta Gas Light to commit to strategic economic development projects.

The i-SRP program authorized $445 million of capital spending through 2017 for projects to upgrade Atlanta Gas Light's distribution system and LNG facilities in Georgia, improve its peak-day system reliability and operational flexibility, and create a platform to meet long-term forecasted growth. In August 2016, Atlanta Gas Light filed a petition with the Georgia PSC for approval of a four-year extension of its i-SRP seeking approval to invest an additional $177 million to improve and upgrade its core gas distribution system in years 2017 through 2020.

The i-VPR program authorized Atlanta Gas Light to spend $275 million through 2017 to replace 756 miles of aging plastic pipe that was installed primarily in the mid-1960s to the early 1980s. Atlanta Gas Light has identified approximately 3,300 miles of vintage plastic mains in its system that should be considered for potential replacement.

See "Base Rate Cases" herein for additional information on GRAM.

*Elizabethtown Gas*

Elizabethtown Gas' 2013 extension of the AIR enhanced infrastructure program allowed for infrastructure investment of $115 million over four years and was focused on the replacement of aging cast iron in its pipeline system. Carrying charges on the additional capital spend are being accrued and deferred for regulatory purposes at a weighted average cost of capital of 6.65%. Effective July 1, 2017, investments under this program, which ended September 30, 2017, are being recovered through base rate revenues. See "Base Rate Cases" herein for additional information.

In 2015, Elizabethtown Gas filed the Safety, Modernization and Reliability Tariff plan with the New Jersey BPU seeking approval to invest more than $1.1 billion to replace 630 miles of vintage cast iron, steel, and copper pipeline, as well as 240 regulator stations. During the first quarter 2018, Elizabethtown Gas withdrew this filing in response to a proposed rule by the New Jersey BPU to incentivize utilities to accelerate investment in infrastructure replacement programs that enhance reliability, resiliency, and/or safety of the distribution system. Elizabethtown Gas expects to file a revised plan during the second half of 2018. The ultimate outcome of this matter cannot be determined at this time.

*Virginia Natural Gas*

In 2012, the Virginia Commission approved the SAVE program, an accelerated infrastructure replacement program, to be completed over a five -year period. This program included a maximum allowance for capital expenditures of $25 million per year, not to exceed $105 million in total.

In March 2016, the Virginia Commission approved an extension to the SAVE program for Virginia Natural Gas to replace more than 200 miles of aging pipeline infrastructure and invest up to $30 million in 2016 and up to $35 million annually through 2021. Virginia Natural Gas expects to invest $35 million under this program in 2018 .

The SAVE program is subject to annual review by the Virginia Commission. In conjunction with the base rate case order issued by the Virginia Commission on December 21, 2017, Virginia Natural Gas is recovering the portion of these program costs incurred prior to September 1, 2017 through base rates. See "Base Rate Cases" herein for additional information.

*Florida City Gas*

In 2015, the Florida PSC approved Florida City Gas' SAFE, under which costs incurred for replacing aging pipes are recovered through a rate rider with annual adjustments and true-ups. Under the program, Florida City Gas is authorized to spend $105 million over a 10-year period on infrastructure relocation and enhancement projects. Florida City Gas expects to invest $10 million under this program in 2018 .

***PRP Settlement***

In 2015, Atlanta Gas Light received a final order from the Georgia PSC for a rate true-up of allowed unrecovered revenue through 2014 related to its PRP. This order allows Atlanta Gas Light to recover $144 million of the $178 million previously unrecovered program revenue. The remaining $34 million requested related primarily to previously unrecognized ratemaking amounts and did not have a material impact on the Company's financial statements. The Company also recognized $1 million of interest expense and $5 million in operations and maintenance expense related to the PRP on the Company's statements of income for the predecessor year ended December 31, 2015. See "Unrecognized Ratemaking Amounts" herein for additional information.

As a result of the PRP settlement, Atlanta Gas Light began recovering incremental PRP surcharge amounts through three phased in increases in addition to its already existing PRP surcharge amount, which was established to address recovery of the unrecovered PRP balance of $144 million in 2015 and the estimated amounts to be earned under the program through 2025. The initial incremental surcharge of approximately $15 million annually was effective in October 2015, with additional annual increases of approximately $15 million in each of October 2016 and 2017. The final increase scheduled for October 2017 was included in the implementation of GRAM in March 2017. The under recovered balance is the result of the continued revenue requirement earned under the program offset by the existing and incremental PRP surcharges. The unrecovered balance at December 31, 2017 was $187 million, including $104 million of unrecognized equity return. The PRP surcharge will remain in effect until the earlier of the full recovery of the under recovered amount or December 31, 2025. See "Base Rate Cases" herein for additional information on GRAM.

One of the capital projects under the PRP experienced construction issues and Atlanta Gas Light was required to complete mitigation work prior to placing it in service. These mitigation costs will be included in future base rates in 2018. Provisions in the order resulted in the recognition of $5 million in operations and maintenance expense for the predecessor year ended December 31, 2015 on the Company's statements of income. In 2017, Atlanta Gas Light recovered $20 million from the settlement of contractor litigation claims and continues to pursue contractual and legal claims against a third-party contractor. Mitigation costs recovered through the legal process are retained by Atlanta Gas Light. The ultimate outcome of this matter cannot be determined at this time.

***Base Rate Cases***

*Settled Base Rate Cases*

On February 21, 2017, the Georgia PSC approved GRAM and a $20 million increase in annual base rate revenues for Atlanta Gas Light, effective March 1, 2017. GRAM adjusts base rates annually, up or down, using an earnings band based on the previously approved ROE of 10.75% and does not collect revenue through special riders and surcharges. Atlanta Gas Light adjusts rates up to the lower end of the band of 10.55% and adjusts rates down to the higher end of the band of 10.95%. Various infrastructure programs previously authorized by the Georgia PSC under Atlanta Gas Light's STRIDE program, which include i-VPR and i-SRP, will continue under GRAM and the recovery of and return on the infrastructure program investments will be included in annual base rate adjustments. The Georgia PSC will review Atlanta Gas Light's performance annually under GRAM.

Pursuant to the GRAM approval, Atlanta Gas Light and the staff of the Georgia PSC agreed to a variation to the i-CGP that was formerly part of Atlanta Gas Light's STRIDE program. As a result, a new tariff was created, effective October 10, 2017, to provide up to $15 million annually for Atlanta Gas Light to commit to strategic economic development projects. Projects under this tariff must be approved by the Georgia PSC.

Beginning with the next rate adjustment in June 2018, Atlanta Gas Light's recovery of the previously unrecovered Pipeline Replacement Program revenue through 2014, as well as the mitigation costs associated with the Pipeline Replacement Program that were not previously included in its rates, will also be included in GRAM. In connection with the GRAM approval, the last monthly Pipeline Replacement Program surcharge increase became effective March 1, 2017.

On June 30, 2017, the New Jersey BPU approved a settlement that provides for a $13 million increase in annual base rate revenues, effective July 1, 2017, based on a ROE of 9.6%. Also included in the settlement was a new composite depreciation rate that is expected to result in a $3 million annual reduction of depreciation. See Note 11 to the financial statements under "Proposed Sale of Elizabethtown Gas and Elkton Gas" for information on the proposed sale of Elizabethtown Gas.

On December 21, 2017, the Virginia Commission approved a settlement for a $34 million increase in annual base rate revenues, effective September 1, 2017, including $13 million related to the recovery of investments under the SAVE program. See "Infrastructure Replacement Programs and Capital Projects" herein for additional information. An authorized ROE range of 9.0% to 10.0% with a midpoint of 9.5% will be used to determine the revenue requirement in any filing, other than for a change in base rates.

On January 31, 2018, the Illinois Commission approved a $137 million increase in annual base rate revenues, including $93 million related to the recovery of investments under the Investing in Illinois program, effective February 8, 2018, based on a ROE of 9.8%.

*Pending Base Rate Cases*

On October 23, 2017, Florida City Gas filed a general base rate case with the Florida PSC requesting a $19 million increase in annual base rate revenues. On January 29, 2018, Florida City Gas filed an update to incorporate the effects of the Tax Reform Legislation that, if approved, would reduce the requested base rate revenues by $4 million. The requested increase is based on a 2018 projected test year and a ROE of 11.25%. The requested increase includes $3 million related to the recovery of investments under SAFE that are currently being recovered through a surcharge. Additionally, Florida City Gas requested an interim rate increase of $5 million annually that was approved and became effective January 12, 2018, subject to refund. The Florida PSC is expected to rule on the requested increase in mid-2018.

On December 1, 2017, Atlanta Gas Light filed its 2018 annual rate adjustment with the Georgia PSC. If approved, annual base rate revenues will increase by $22 million, effective June 1, 2018. Atlanta Gas Light will file a revised rate adjustment to incorporate the effects of the Tax Reform Legislation in the first quarter 2018. The Georgia PSC is expected to rule on the revised requested increase in the second quarter 2018.

On February 15, 2018, Chattanooga Gas filed a general base rate case with the Tennessee Public Utility Commission requesting a $7 million increase in annual base rate revenues. The requested increase, which incorporated the effects of the Tax Reform Legislation, was based on a projected test year ending June 30, 2019 and a ROE of 11.25%. The Tennessee Public Utility Commission is expected to rule on the requested increase in the third quarter 2018.

The ultimate outcome of these pending base rate cases cannot be determined at this time.

***Other***

The New Jersey BPU, Virginia Commission, Tennessee Public Utility Commission, and Maryland PSC each issued an order effective January 1, 2018 that requires utilities in their respective states to track as a regulatory liability the impact of the Tax Reform Legislation, including the reduction in the corporate income tax rate to 21% and the impact of excess deferred income taxes. The New Jersey BPU's order requires Elizabethtown Gas to file by March 2, 2018 proposed revised base rates with an April 1, 2018 interim effective date and a July 1, 2018 final effective date. Virginia Natural Gas will address the Virginia Commission's order in its Annual Information Filing, which will be filed by July 1, 2018. The Tennessee Public Utility Commission's order required Chattanooga Gas to file proposals to reduce rates or make other ratemaking adjustments to account for the impact of the Tax Reform Legislation. Chattanooga Gas made the required filing as part of its February 15, 2018 general base rate case filing. The Maryland PSC's order required Elkton Gas to file an explanation of the impact of the Tax Reform Legislation on its expenses and revenues, as well as when and how it expects to pass through to its customers those effects. Elkton Gas made the required filing on February 15, 2018 and will reduce annual base rates by $0.1 million effective April 1, 2018. Credits will be issued to customers for the impact of the Tax Reform Legislation from January 2018 through March 2018.

The Illinois Commission issued an order effective January 25, 2018 that requires utilities in the state to record the impacts of the Tax Reform Legislation, including the reduction in the corporate income tax rate to 21% and the impact of excess deferred income taxes, as a regulatory liability. On February 20, 2018, the Illinois Commission granted Nicor Gas' application for rehearing to file revised base rates and tariffs, which Nicor Gas expects to file by the end of the second quarter 2018.

The ultimate outcome of these matters cannot be determined at this time.

***Asset Management Agreements***

All of the natural gas distribution utilities except Nicor Gas use asset management agreements with the Company's wholly-owned subsidiary, Sequent, for the primary purpose of reducing utility customers' gas cost recovery rates through payments to the utilities by Sequent. For Atlanta Gas Light, these payments are controlled by the Georgia PSC and are utilized for infrastructure improvements and to fund heating assistance programs, rather than as a reduction to gas cost recovery rates. Under these asset management agreements, Sequent supplies natural gas to the utility and markets available pipeline and storage capacity to improve the overall cost of supplying gas to the utility customers. Currently, the Company's utilities primarily purchase their gas from Sequent. The purchase agreements require Sequent to provide firm gas to the natural gas distribution utilities, but these natural gas distribution utilities maintain the right and ability to make their own long-term supply arrangements if they believe it is in the best interest of their customers.

Each agreement provides for Sequent to make payments to the natural gas distribution utilities through either an annual minimum guarantee within a profit sharing structure, a profit sharing structure without an annual minimum guarantee, or a fixed fee. From the inception of these agreements in 2001 through December 31, 2017 , Sequent made sharing payments to the natural gas distribution utilities under these agreements totaling $390 million .

The following table provides payments made by Sequent to the natural gas distribution utilities under these agreements during the last three years:

| | Successor | | Predecessor | | |
|---|---|---|---|---|---|
| | Total Amount Received | | Total Amount Received | | |
| | **Year Ended December 31, 2017** | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | Year Ended December 31, 2015 | Expiration Date |
| | *(in millions)* | | *(in millions)* | | |
| Elizabethtown Gas | **$ 11** | $ 3 | $ 12 | $ 28 | March 2019 |
| Virginia Natural Gas | **6** | 2 | 9 | 15 | March 2019 |
| Atlanta Gas Light | **4** | 1 | 6 | 15 | March 2020 |
| Florida City Gas | **1** | — | 1 | 1 | (a) |
| Chattanooga Gas | **1** | — | 1 | 1 | March 2021 |
| Total (b) | **$ 23** | $ 6 | $ 29 | $ 60 | |

(a) The agreement renews automatically each year unless terminated by either party.

(b) Payments made to Elkton Gas were less than $1 million for each of the periods presented.

Upon consummation of the asset sales of Elizabethtown Gas and Elkton Gas, South Jersey Industries, Inc. will assume the asset management agreements of Elizabethtown Gas and Elkton Gas. See Note 11 to the financial statements under "Proposed Sale of Elizabethtown Gas and Elkton Gas" for additional information on these sales.

***energySMART***

In 2014, the Illinois Commission approved Nicor Gas' energySMART through 2017, which outlined energy efficiency program offerings and therm reduction goals, and subsequently extended the program to 2021. Through December 31, 2017, Nicor Gas spent $107 million of the initial authorized expenditure of $113 million . A new four-year program began on January 1, 2018, with an additional authorized expenditure of $160 million. Nicor Gas expects to invest $40 million under this program in 2018 .

***Unrecognized Ratemaking Amounts***

The following table illustrates the Company's authorized ratemaking amounts that are not recognized on its balance sheets. These amounts are primarily composed of an allowed equity rate of return on assets associated with certain of the Company's regulatory infrastructure programs. These amounts will be recognized as revenues in the Company's financial statements in the periods they are billable to customers, the majority of which will be recovered by 2025.

| | **December 31, 2017** | December 31, 2016 |
|---|---|---|
| | *(in millions)* | |
| Atlanta Gas Light | **$ 104** | $ 110 |
| Virginia Natural Gas | **11** | 11 |
| Elizabethtown Gas (*) | **8** | 6 |
| Nicor Gas | **2** | 2 |
| Total | **$ 125** | $ 129 |

(*) See Note 11 to the financial statements under "Proposed Sale of Elizabethtown Gas and Elkton Gas" for information on the pending asset sale.

## Income Tax Matters

### *Federal Tax Reform Legislation*

On December 22, 2017, the Tax Reform Legislation was signed into law and became effective on January 1, 2018. The Tax Reform Legislation, among other things, reduces the federal corporate income tax rate to 21%, retains normalization provisions for public utility property and existing renewable energy incentives, and repeals the corporate alternative minimum tax.

For businesses other than regulated utilities, the Tax Reform Legislation allows 100% bonus depreciation of qualified property acquired and placed in service between September 28, 2017 and January 1, 2023 and phases down by 20% each year until completely phased out for qualified property placed in service after December 31, 2027. Further, the business interest deduction is limited to 30% of taxable income excluding interest, net operating loss (NOL) carryforwards, and depreciation and amortization through December 31, 2021 and thereafter to 30% of taxable income excluding interest and NOL carryforwards.

Regulated utility businesses, including the natural gas distribution companies, can continue deducting all business interest expense and are not eligible for bonus depreciation on capital assets acquired and placed in service after September 27, 2017. Projects with binding contracts before September 28, 2017 and placed in service after September 27, 2017 remain eligible for bonus depreciation under the Protecting Americans from Tax Hikes (PATH) Act.

In addition, under the the Tax Reform Legislation, NOLs generated after December 31, 2017 can no longer be carried back to previous tax years but can be carried forward indefinitely, with utilization limited to 80% of taxable income of the subsequent tax year.

For the year ended December 31, 2017, implementation of the Tax Reform Legislation resulted in an estimated net tax expense of $93 million and a $777 million increase in regulatory liabilities, primarily due to the impact of the reduction of the corporate income tax rate on deferred tax assets and liabilities .

The Tax Reform Legislation is subject to further interpretation and guidance from the IRS, as well as each respective state's adoption. In addition, the regulatory treatment of certain impacts of Tax Reform Legislation is subject to the discretion of the FERC and the relevant state regulatory bodies as further described in Note 3 to the financial statements under "Base Rate Cases" and "Other" for additional information.

See FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein and Note 5 to the financial statements under " Current and Deferred Income Taxes " for additional information.

The ultimate outcome of these matters cannot be determined at this time.

### *Bonus Depreciation*

Under the Tax Reform Legislation, projects with binding contracts prior to September 28, 2017 and placed in service after September 27, 2017 remain eligible for bonus depreciation under the PATH Act. The PATH Act allowed for 50% bonus depreciation for 2015 through 2017, 40% bonus depreciation for 2018, and 30% bonus depreciation for 2019 and certain long-lived assets placed in service in 2020. Based on provisional estimates, bonus depreciation is expected to result in positive cash flows of approximately $200 million for the 2017 tax year and approximately $60 million for the 2018 tax year. Should Southern Company have a NOL in 2018, all of these cash flows may not be fully realized in 2018 . See Note 5 to the financial statements under "Current and Deferred Income Taxes" for additional information. The ultimate outcome of this matter cannot be determined at this time.

### *State Tax Reform Legislation*

On July 6, 2017, the State of Illinois enacted tax legislation that repealed its non-combination tax rule and increased the effective corporate income tax rate from 5.25% to 7.0% (making the total corporate tax rate 9.5% when combined with the 2.5% personal property replacement tax) effective July 1, 2017. In addition to increasing taxes on future earnings, this legislation required the Company to increase accumulated deferred income tax liabilities by $24 million during the third quarter 2017 to reflect these changes, of which $15 million was expensed and $9 million was recorded as a regulatory asset.

### *Change in State Apportionment Factors*

Southern Company calculated new apportionment factors in several states to include the Company in its consolidated tax filings, which resulted in $22 million of additional deferred income tax expenses in the successor year ended December 31, 2017.

**Other Matters**

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business.

Nicor Gas and Nicor Energy Services Company, wholly-owned subsidiaries of the Company, and Nicor Inc. were defendants in a putative class action initially filed in 2011 in the state court in Cook County, Illinois. The plaintiffs purported to represent a class of the customers who purchased the Gas Line Comfort Guard product from Nicor Energy Services Company and variously alleged that the marketing, sale, and billing of the Gas Line Comfort Guard product violated the Illinois Consumer Fraud and Deceptive Business Practices Act, constituting common law fraud and resulting in unjust enrichment of these entities. The plaintiffs sought, on behalf of the classes they purported to represent, actual and punitive damages, interest, costs, attorney fees, and injunctive relief. On February 8, 2017, the judge denied the plaintiffs' motion for class certification and the Company's motion for summary judgment. On March 7, 2017, the parties reached a settlement, which was finalized and effective on April 3, 2017. The settlement did not have a material impact on the Company's financial statements.

The Company is assessing its alleged involvement in an incident that occurred in one of its service territories that resulted in several deaths, injuries, and property damage. One of the natural gas distribution utilities has been named as one of the defendants in several lawsuits related to this incident. The Company has insurance that provides full coverage of any financial exposure in excess of $11 million per incident. During the successor period ended December 31, 2016 and the predecessor period ended December 31, 2015, the Company recorded reserves for substantially all of its potential exposure from these cases.

The ultimate outcome of these matters and such pending or potential litigation or regulatory matters cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements under "General Litigation Matters" for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

The Company owns a 50% interest in a planned LNG liquefaction and storage facility in Jacksonville, Florida. Once construction is complete and the facility is operational, it will be outfitted with a 2.0 million gallon storage tank with the capacity to produce in excess of 120,000 gallons of LNG per day. It is expected to be operational in the first half of 2018. The ultimate outcome of this matter cannot be determined at this time.

A wholly-owned subsidiary of the Company owns and operates a natural gas storage facility consisting of two salt dome caverns in Louisiana. Periodic integrity tests are required in accordance with rules of the Louisiana Department of Natural Resources (DNR). In August 2017, in connection with an ongoing integrity project, updated seismic mapping indicated the proximity of one of the caverns to the edge of the salt dome may be less than the required minimum and could result in the Company retiring the cavern early. At December 31, 2017, the facility's property, plant, and equipment had a net book value of $112 million, of which the cavern itself represents approximately 20%. A potential early retirement of this cavern is dependent upon several factors including compliance with an order from the Louisiana DNR detailing the requirements to place the cavern back in service, which includes, among other things, obtaining core samples to determine the composition of the sheath surrounding the edge of the salt dome.

The cavern continues to maintain its pressures and overall structural integrity. The Company intends to monitor the cavern and comply with the Louisiana DNR order through 2020 and place the cavern back in service in 2021. These events were considered in connection with the Company's annual long-lived asset impairment analysis, which determined there was no impairment as of December 31, 2017. Any changes in results of monitoring activities, rates at which expiring capacity contracts are re-contracted, timing of placing the cavern back in service, or Louisiana DNR requirements could trigger impairment. Further, early retirement of the cavern could trigger impairment of other long-lived assets associated with the natural gas storage facility. The ultimate outcome of this matter cannot be determined at this time, but could have a material impact on the Company's financial statements.

Effective January 1, 2018, the Company conformed its paid time off policy to align with Southern Company. Under the new policy, paid time off days are vested by the employee on the first day of each year and will continue to be recovered through rates on an as-paid basis. As a result, the Company accrued $21 million as of January 1, 2018, of which $9 million was recorded as a regulatory asset.

**ACCOUNTING POLICIES**

**Application of Critical Accounting Policies and Estimates**

The Company prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the

Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

***Utility Regulation***

The natural gas distribution utilities comprised approximately 82% of the Company's total operating revenues for 2017 and are subject to rate regulation by their respective state regulatory agencies, which set the rates utilities are permitted to charge customers based on allowable costs, including a reasonable ROE. As a result, the natural gas distribution utilities apply accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the natural gas distribution utilities; therefore, the accounting estimates inherent in specific costs such as depreciation and pension and other postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and any requirement to refund these regulatory liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

***Accounting for Income Taxes***

The consolidated income tax provision and deferred income tax assets and liabilities, as well as any unrecognized tax benefits and valuation allowances, require significant judgment and estimates. These estimates are supported by historical tax return data, reasonable projections of taxable income and interpretations of applicable tax laws and regulations across multiple taxing jurisdictions. The effective tax rate reflects the statutory tax rates and calculated apportionments for the many states in which the Company operates.

On behalf of the Company, Southern Company files a consolidated federal income tax return and various state income tax returns, some of which are combined or unitary. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. Certain deductions and credits can be limited at the consolidated or combined level resulting in NOL and tax credit carryforwards that would not otherwise result on a stand-alone basis. Utilization of NOL carryforwards and the assessment of valuation allowances are based on significant judgment and extensive analysis of the Company's, as well as Southern Company's, current financial position and result of operations, including currently available information about future years, to estimate when future taxable income will be realized.

Current and deferred state income tax liabilities and assets are estimated based on laws of multiple states that determine the income to be apportioned to their jurisdictions. States utilize various formulas to calculate the apportionment of taxable income, primarily using sales, assets or payroll within the jurisdiction compared to the consolidated totals. In addition, each state varies as to whether a stand-alone, combined or unitary filing methodology is required. The calculation of deferred state taxes considers apportionment factors and filing methodologies that are expected to apply in future years. The apportionments and methodologies which are ultimately finalized in a manner inconsistent with expectations could have a material effect on the Company's financial statements.

Given the significant judgment involved in estimating NOL carryforwards and tax credit carryforwards and multi-state apportionments, the Company considers state deferred income tax liabilities and assets to be critical accounting estimates.

***Federal Tax Reform Legislation***

Following the enactment of the Tax Reform Legislation, the SEC staff issued Staff Accounting Bulletin 118 – "Income Tax Accounting Implications of the Tax Cuts and Jobs Act" (SAB 118), which provides for a measurement period of up to one year from the enactment date to complete accounting under GAAP for the tax effects of the legislation. Due to the complex and comprehensive nature of the enacted tax law changes, and their application under GAAP, the Company considers all amounts recorded in the financial statements as a result of the Tax Reform Legislation to be "provisional" as discussed in SAB 118 and subject to revision. The Company is awaiting additional guidance from industry and income tax authorities in order to finalize its accounting. The ultimate impact of the Tax Reform Legislation on deferred income tax assets and liabilities and the related regulatory liabilities cannot be determined at this time. See " Income Tax Matters – Federal Tax Reform Legislation " herein and Note 3 to the financial statements under "Base Rate Cases" and "Other" and Note 5 to the financial statements under "Current and Deferred Income Taxes" for additional information.

***Assessment of Assets***

*Goodwill*

The Company does not amortize its goodwill, but tests it annually for impairment at the reporting unit level during the fourth quarter or more frequently if impairment indicators arise. These indicators include, but are not limited to, a significant change in operating performance, the business climate, legal or regulatory factors, or a planned sale or disposition of a significant portion of the business. A reporting unit is the operating segment, or a business one level below the operating segment (a component), if discrete financial information is prepared and regularly reviewed by management. Components are aggregated if they have similar economic characteristics.

As part of the Company's impairment test, the Company may perform an initial qualitative Step 0 assessment to determine whether it is more likely than not that the fair value of each reporting unit is less than its carrying amount before applying the two-step, quantitative goodwill impairment test. If the Company elects to perform the qualitative assessment, it evaluates relevant events and circumstances, including but not limited to, macroeconomic conditions, industry and market conditions, cost factors, financial performance, entity specific events, and events specific to each reporting unit. If the Company determines that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, or it elects not to perform a qualitative assessment, it performs the two-step goodwill impairment test.

Step 1 of the two-step goodwill impairment test compares the fair value of the reporting unit to its carrying value. If the result of the Step 1 test reveals that the estimated fair value is below its carrying value, the Company proceeds with Step 2.

Step 2 of the two-step goodwill impairment test compares the implied fair value of goodwill, which is calculated as the residual amount from the reporting unit's overall fair value after assigning fair values to its assets and liabilities under a hypothetical purchase price allocation as if the reporting unit had been acquired in a business combination, to its carrying value. Based on the result of the Step 2 test, the Company records a goodwill impairment charge for any excess of carrying value over the implied fair value of goodwill.

For the 2017 annual impairment test, the Company performed Step 1 of the two-step impairment test, which resulted in the fair value of all of its reporting units that have goodwill exceeding their carrying value. For the 2016 and 2015 annual impairment tests, the Company performed the qualitative Step 0 assessment and determined that it was more likely than not that the fair value of all of its reporting units with goodwill exceeded their carrying amounts, and therefore no quantitative analysis was required. In the third quarter 2015, the Company identified potential impairment indicators and performed an interim impairment test for its storage and fuels reporting unit, which resulted in impairment of the full $14 million goodwill balance for that reporting unit.

As the determination of an asset's fair value and useful life involves management making certain estimates and because these estimates form the basis for the determination of whether or not an impairment charge should be recorded, the Company considers these estimates to be critical accounting estimates.

See "Recently Issued Accounting Standards – Other" herein for information on the Company's adoption of ASU No. 2017-04 effective January 1, 2018.

*Long-Lived Assets*

The Company depreciates or amortizes its long-lived and intangible assets over their estimated useful lives. The Company assesses its long-lived and intangible assets for impairment whenever events or changes in circumstances indicate that an asset's carrying amount may not be recoverable. When such events or circumstances are present, the Company assesses the recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. Impairment is indicated if the carrying amount of a long-lived asset exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If impairment is indicated, the Company records an impairment loss equal to the difference between the carrying value and the fair value of the long-lived asset.

As the determination of the expected future cash flows generated from an asset, an asset's fair value, and useful life involves management making certain estimates and because these estimates form the basis for the determination of whether or not an impairment charge should be recorded, the Company considers these estimates to be critical accounting estimates.

***Derivatives and Hedging Activities***

Determining whether a contract meets the definition of a derivative instrument, contains an embedded derivative requiring bifurcation, or qualifies for hedge accounting treatment is voluminous and complex. The treatment of a single contract may vary from period to period depending upon accounting elections, changes in the Company's assessment of the likelihood of future hedged transactions, or new interpretations of accounting guidance. As a result, judgment is required in determining the appropriate accounting treatment. In addition, the estimated fair value of derivative instruments may change significantly from period to period depending upon market conditions, and changes in hedge effectiveness may impact the accounting treatment.

Derivative instruments (including certain derivative instruments embedded in other contracts) are recorded on the balance sheets as either assets or liabilities measured at their fair value. If the transaction qualifies for, and is designated as, a normal purchase or normal sale, it is exempted from fair value accounting treatment and is, instead, subject to traditional accrual accounting. The Company utilizes market data or assumptions that market participants would use in pricing the derivative asset or liability, including assumptions about risk and the risks inherent in the inputs of the valuation technique.

Changes in the derivatives' fair value are recognized concurrently in earnings unless specific hedge accounting criteria are met. If the derivatives meet those criteria, derivative gains and losses offset related results of the hedged item in the income statement in the case of a fair value hedge, or gains and losses are recorded in OCI on the balance sheets until the hedged transaction affects earnings in the case of a cash flow hedge. Additionally, a company is required to formally designate a derivative as a hedge as well as document and assess the effectiveness of derivatives associated with transactions that receive hedge accounting treatment.

Nicor Gas and Elizabethtown Gas utilize derivative instruments to hedge the price risk for the purchase of natural gas for customers. These derivatives are reflected at fair value and are not designated as accounting hedges. Realized gains or losses on such instruments are included in the cost of gas delivered and are passed through directly to customers, subject to review by the applicable state regulatory agencies, and therefore have no direct impact on earnings. Unrealized changes in the fair value of these derivative instruments are deferred as regulatory assets or liabilities.

The Company uses derivative instruments primarily to reduce the impact to its results of operations due to the risk of changes in the price of natural gas and to a lesser extent the Company hedges against warmer-than-normal weather and interest rates. The fair value of natural gas derivative instruments used to manage exposure to changing natural gas prices reflects the estimated amounts that the Company would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains or losses on open contracts. For derivatives utilized at gas marketing services and wholesale gas services that are not designated as accounting hedges, changes in fair value are reported as gains or losses in the Company's results of operations in the period of change. Gas marketing services records derivative gains or losses arising from cash flow hedges in OCI and reclassifies them into earnings in the same period that the underlying hedged item is recognized in earnings.

The Company classifies derivative assets and liabilities based on the lowest level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy. The determination of the fair value of the derivative instruments incorporates various required factors. These factors include:

- the creditworthiness of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit);
- events specific to a given counterparty; and
- the impact of the Company's nonperformance risk on its liabilities.

If there is a significant change in the underlying market prices or pricing assumptions the Company uses in pricing its derivative assets or liabilities, the Company may experience a significant impact on its financial position, results of operations, and cash flows. See Note 10 to the financial statements for additional information.

Given the assumptions used in pricing the derivative asset or liability, the Company considers the valuation of derivative assets and liabilities a critical accounting estimate. See FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" herein for more information.

***Pension and Other Postretirement Benefits***

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on pension and other postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. For purposes of determining its liability related to the pension and other postretirement benefit plans, the Company discounts the future related cash flows using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments. Prior to 2016, the Company computed the interest cost component of its net periodic pension and other postretirement benefit plan expense using the same single-point discount rate. In 2016, the Company adopted a full yield curve approach for calculating the interest cost component whereby the discount rate for each year is applied to the liability for that specific year. As a result, the interest cost component of net periodic pension and other postretirement benefit plan expense decreased by approximately $ 7 million in 2016.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $2 million or less change in total annual benefit expense and a $42 million or less change in projected obligations.

See Note 2 to the financial statements for additional information regarding pension and other postretirement benefits.

***Contingent Obligations***

The Company is subject to a number of federal and state laws and regulations as well as other factors and conditions that subject it to environmental, litigation, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's results of operations, cash flows, or financial condition.

**Recently Issued Accounting Standards**

***Revenue***

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers* (ASC 606), replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the new standard is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

Most of the Company's revenue, including energy provided to customers, is from tariff offerings that provide natural gas without a defined contractual term, as well as longer-term contractual agreements, including non-derivative natural gas asset management and optimization arrangements.

The Company has completed the evaluation of all revenue streams and determined that the adoption of ASC 606 will not change the current timing of revenue recognition for such transactions. Some revenue arrangements, such as energy-related derivatives and alternative revenue programs, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed or presented separately from revenues under ASC 606 on the Company's financial statements. The Company has concluded contributions in aid of construction are not in scope for ASC 606 and will continue to be accounted for as an offset to property, plant, and equipment.

The new standard is effective for reporting periods beginning after December 15, 2017. The Company applied the modified retrospective method of adoption effective January 1, 2018. The Company also utilized practical expedients which allowed it to apply the standard to open contracts at the date of adoption and to reflect the aggregate effect of all modifications when identifying performance obligations and allocating the transaction price for contracts modified before the effective date. Under the modified retrospective method of adoption, prior year reported results are not restated; however, a cumulative-effect adjustment to retained earnings at January 1, 2018 is recorded. In addition, quarterly disclosures will include comparative information on 2018 financial statement line items under current guidance. The adoption of ASC 606 did not result in a cumulative-effect adjustment .

***Leases***

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged . ASU 2016-02 is effective for fiscal years beginning after December 15, 2018 and the Company will adopt the new standard effective January 1, 2019.

The Company is currently implementing an information technology system along with the related changes to internal controls and accounting policies that will support the accounting for leases under ASU 2016-02. In addition, the Company has substantially completed a detailed inventory and analysis of its leases. In terms of rental charges and duration of contracts, the most significant leases relate to real estate and fleet vehicles where the Company is the lessee and to natural gas home appliances where the Company is the lessor. While the Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

***Other***

In November 2016, the FASB issued ASU No. 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash* (ASU 2016-18). ASU 2016-18 eliminates the need to reflect transfers between cash and restricted cash in operating, investing, and financing activities in the statement of cash flows. Upon adoption, the net change in cash and cash equivalents during the period will include amounts generally described as restricted cash or restricted cash equivalents. ASU 2016-18 is effective for fiscal years beginning after December 15, 2017, and will be applied retrospectively to each period presented. The Company adopted ASU 2016-18 effective January 1, 2018 with no material impact on its financial statements.

On January 26, 2017, the FASB issued ASU No. 2017-04, *Intangibles – Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment* (ASU 2017-04). ASU 2017-04 removes the requirement to compare the implied fair value of goodwill with the carrying amount as part of Step 2 of the goodwill impairment test. Under the new standard, the goodwill impairment loss will be measured as the excess of a reporting unit's carrying amount over its fair value, not exceeding the total amount of goodwill allocated to that reporting unit, which may increase the frequency of goodwill impairment charges if a future goodwill impairment test does not pass the Step 1 evaluation. ASU 2017-04 is effective prospectively for periods beginning on or after December 15, 2019, with early adoption permitted. The Company adopted ASU 2017-04 effective January 1, 2018 with no impact on its financial statements.

On March 10, 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017-07). ASU 2017-07 requires that an employer report the service cost component in the same line item or items as other compensation costs and requires the other components of net periodic pension and postretirement benefit costs to be separately presented in the income statement outside of income from operations. Additionally, only the service cost component is eligible for capitalization, when applicable. However, all cost components remain eligible for capitalization under FERC regulations. ASU 2017-07 will be applied retrospectively for the presentation of the service cost component and the other components of net periodic pension and postretirement benefit costs in the income statement. The capitalization of only the service cost component of net periodic pension and postretirement benefit costs in assets will be applied on a prospective basis. ASU 2017-07 is effective for periods beginning after December 15, 2017. The presentation changes required for net periodic pension and postretirement benefit costs will result in a decrease in the Company's operating income and an increase in other income for 2016 and 2017 and are expected to result in a decrease in operating income and an increase in other income for 2018. The Company adopted ASU 2017-07 effective January 1, 2018 with no material impact on its financial statements.

On August 28, 2017, the FASB issued ASU No. 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities* (ASU 2017-12), amending the hedge accounting recognition and presentation requirements. ASU 2017-12 makes more financial and non-financial hedging strategies eligible for hedge accounting, amends the related presentation and disclosure requirements, and simplifies hedge effectiveness assessment requirements. ASU 2017-12 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

## FINANCIAL CONDITION AND LIQUIDITY

### Overview

The Company's financial condition remained stable at December 31, 2017 . The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to maintain existing natural gas distribution systems as well as to update and expand these systems, and to comply with environmental regulations. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2018 through 2020 , the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. The Company plans to finance future cash needs in excess of its operating cash flows primarily through external securities issuances, equity contributions from Southern Company, and borrowings from financial institutions and with proceeds from the pending asset sales of Elizabethtown Gas and Elkton Gas. The Company plans to use commercial paper to manage seasonal variations in operating cash flows and other working capital needs. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See " Sources of Capital ," " Financing Activities ," and " Capital Requirements and Contractual Obligations " herein for additional information.

By regulation, Nicor Gas is restricted, to the extent of its retained earnings balance, in the amount it can dividend or loan to affiliates and is not permitted to make money pool loans to affiliates. The New Jersey BPU restricts the amount Elizabethtown Gas can dividend to its parent company to 70% of its quarterly net income. Additionally, as stipulated in the New Jersey BPU's order approving the Merger, the Company is prohibited from paying dividends to its parent company, Southern Company, if the Company's senior unsecured debt rating falls below investment grade. At December 31, 2017 , the amount of subsidiary retained earnings and net income restricted to dividend totaled $719 million . These restrictions did not have any impact on the Company's ability to meet its cash obligations, nor does management expect such restrictions to materially impact the Company's ability to meet its currently anticipated cash obligations.

The Company's investments in the qualified pension plan increased in value at December 31, 2017 as compared to December 31, 2016 . There were no voluntary contributions to the qualified pension plan in 2017 and no mandatory contributions to its qualified pension plan are anticipated during 2018 . See Note 2 to the financial statements for additional information.

Net cash provided from operating activities totaled $883 million for 2017 , primarily due to earnings and the timing of cash receipts for the sale of natural gas inventory and vendor payments. Net cash used for operating activities was $328 million for the successor period of July 1, 2016 through December 31, 2016 , primarily due to a $125 million voluntary pension contribution, a $35 million payment for the settlement of an interest rate swap, and less cash due to the timing of collecting receivables and disbursing payables. Due to the seasonal nature of its business, the Company typically reports negative cash flows from operating activities in the second half of the year. Net cash provided from operating activities was $1.1 billion for the predecessor period of January 1, 2016 through June 30, 2016 , primarily due to low volumes of natural gas sales and changes in natural gas inventory as a result of warmer weather and the timing of recovery of related gas costs and weather normalization adjustments from customers. Net cash provided from operating activities was $1.4 billion for the predecessor year ended December 31, 2015 , primarily due to the timing of recovery of related gas costs from customers, cash provided from derivative financial instrument assets and liabilities, and a tax refund of $150 million related to the extension of bonus depreciation.

Net cash used for investing activities totaled $1.6 billion for 2017 , which reflected $1.5 billion in capital expenditures primarily due to gross property additions for infrastructure replacement programs at gas distribution operations and $145 million in capital contributions to equity method investments in pipeline projects, partially offset by $80 million in returned capital from equity method investments in pipeline projects. Net cash used for investing activities was $2.1 billion for the successor period of July 1, 2016 through December 31, 2016 , which reflected $1.4 billion primarily related to the Company's acquisition of the 50% interest in SNG, and $632 million in capital expenditures. Net cash used for investing activities was $559 million and $1.0 billion for the predecessor period of January 1, 2016 through June 30, 2016 and the predecessor year ended December 31, 2015 , respectively, which primarily related to capital expenditures. See Note 4 to the financial statements under "Equity Method Investments – SNG" and Note 11 to the financial statements under "Investment in SNG" for additional information.

Net cash provided from financing activities totaled $741 million for 2017 , primarily due to $850 million in debt issuances, $262 million in net additional commercial paper borrowings, and $103 million in capital contributions from Southern Company, partially offset by $443 million in common stock dividend payments to Southern Company and $22 million in repayment of long-term debt. Net cash provided from financing activities was $2.4 billion for the successor period of July 1, 2016 through December 31, 2016 , which reflected $1.1 billion of capital contributions from Southern Company, primarily used to fund the

Company's investment in SNG, $1.1 billion in net additional commercial paper borrowings, partially offset by $160 million for the purchase of the 15% noncontrolling ownership interest in SouthStar, and $900 million in proceeds from debt issuances, partially offset by $420 million in debt payments. Net cash used for financing activities was $558 million for the predecessor period of January 1, 2016 through June 30, 2016 , primarily due to $896 million in net repayment of commercial paper borrowings and $125 million in repayment of long-term debt, partially offset by $600 million in debt issuances. Net cash used for financing activities was $366 million for the predecessor year ended December 31, 2015 , primarily due to the net repayment of commercial paper borrowings, partially offset by the proceeds from debt issuances in excess of debt repayments. See Note 4 to the financial statements under "Variable Interest Entities" and "Equity Method Investments – SNG" and Note 11 to the financial statements under "Investment in SNG" for additional information.

Significant balance sheet changes at December 31, 2017 include an increase of $1.2 billion in total property, plant, and equipment primarily due to capital expenditures for infrastructure replacement programs, an increase of $1.0 billion in deferred credits related to income taxes primarily resulting from the impacts of the Tax Reform Legislation, a decrease of $886 million in accumulated deferred income tax liabilities primarily due to the change in the federal corporate income tax rate, partially offset by tax depreciation related to infrastructure assets placed in service as well as the impact of State of Illinois tax legislation, and an increase in long-term debt of $632 million , primarily due to $450 million of senior notes issued in May 2017 and $200 million of first mortgage bonds at Nicor Gas issued in each of August 2017 and November 2017. Other significant balance sheet changes include an increase of $261 million in notes payable primarily related to an increase in commercial paper borrowings of $510 million at Southern Company Gas Capital, partially offset by a decrease in commercial paper borrowings of $249 million at Nicor Gas. See FUTURE EARNINGS POTENTIAL – " Income Tax Matters " and FINANCIAL CONDITION AND LIQUIDITY – "Financing Activities" herein and Notes 5 and 6 to the financial statements for additional information.

**Sources of Capital**

The Company plans to obtain the funds to meet its future capital needs through operating cash flows, external securities issuances, borrowings from financial institutions, and equity contributions from Southern Company. In addition, the Company plans to utilize the proceeds from the pending asset sales of Elizabethtown Gas and Elkton Gas to pay the income taxes resulting from the sales, to retire existing debt, and for general corporate purposes. However, the amount, type, and timing of any future financings, if needed, depend upon prevailing market conditions, regulatory approval, and other factors. The issuance of securities by Nicor Gas is generally subject to the approval of the Illinois Commission.

The Southern Company system does not maintain a centralized cash or money pool. Therefore, except as described below, funds of the Company are not commingled with funds of any other company in the Southern Company system. The Company obtains financing separately without credit support from any affiliate in the Southern Company system. See Note 6 to the financial statements under " Bank Credit Arrangements " for additional information.

The Company maintains commercial paper programs at Southern Company Gas Capital and Nicor Gas that consist of short-term, unsecured promissory notes. Nicor Gas' commercial paper program supports its working capital needs as Nicor Gas is not permitted to make money pool loans to affiliates. All of the Company's other subsidiaries benefit from Southern Company Gas Capital's commercial paper program.

At December 31, 2017 , the Company's current liabilities exceeded current assets by $1.0 billion , primarily as a result of $1.5 billion in notes payable. The Company's current liabilities frequently exceed current assets because of commercial paper borrowings used to fund daily operations, scheduled maturities of long-term debt, and significant seasonal fluctuations in cash needs. The Company intends to utilize operating cash flows, external securities issuances, borrowings from financial institutions, equity contributions from Southern Company, and the proceeds from the pending asset sales of Elizabethtown Gas and Elkton Gas to fund short-term capital needs. The Company has substantial cash flow from operating activities and access to capital markets and financial institutions to meet liquidity needs.

At December 31, 2017 , the Company had $73 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2017 were as follows:

| **Company** | **Expires 2022** | **Unused** |
|---|---|---|
| | *(millions)* | |
| Southern Company Gas Capital (*) | $ 1,400 | $ 1,390 |
| Nicor Gas | 500 | 500 |
| Total | $ 1,900 | $ 1,890 |

(*) The Company guarantees the obligations of Southern Company Gas Capital.

See Note 6 to the financial statements under " Bank Credit Arrangements " for additional information.

In May 2017, Southern Company Gas Capital and Nicor Gas terminated their existing credit arrangements for $1.3 billion and $700 million, respectively, which were to mature in 2017 and 2018, and entered into a new multi-year credit arrangement (Facility) currently allocated for $1.4 billion and $500 million , respectively, with a maturity date of 2022, as reflected in the table above. Pursuant to the Facility, the allocations between Southern Company Gas Capital and Nicor Gas may be adjusted.

The Facility contains a covenant that limits the ratio of debt to capitalization (as defined in each facility) to a maximum of 70% for each of the Company and Nicor Gas and contains a cross-acceleration provision to other indebtedness (including guarantee obligations) of the applicable company. Such cross-acceleration provision to other indebtedness would trigger an event of default of the applicable company if the Company or Nicor Gas defaulted on indebtedness, the payment of which was then accelerated. At December 31, 2017 , both companies were in compliance with such covenant. The Facility does not contain a material adverse change clause at the time of borrowings.

Subject to applicable market conditions, the applicable company expects to renew or replace the Facility as needed, prior to expiration. In connection therewith, the applicable company may extend the maturity dates and/or increase or decrease the lending commitments thereunder. A portion of unused credit with banks provides liquidity support to the Company.

The Company makes short-term borrowings primarily through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above. Commercial paper borrowings are included in notes payable in the balance sheets.

Details of short-term borrowings were as follows:

| | Short-term Debt at the End of the Period | | Short-term Debt During the Period (*) | | |
|---|---|---|---|---|---|
| | Amount Outstanding | Weighted Average Interest Rate | Average Amount Outstanding | Weighted Average Interest Rate | Maximum Amount Outstanding |
| | *(in millions)* | | *(in millions)* | | *(in millions)* |
| **Successor – December 31, 2017:** | | | | | |
| Southern Company Gas Capital | **$ 1,243** | **1.73%** | **$ 723** | **1.40%** | **$ 1,243** |
| Nicor Gas | **275** | **1.83%** | **176** | **1.12%** | **525** |
| Total | **$ 1,518** | **1.75%** | **$ 899** | **1.35%** | |
| Successor – December 31, 2016: | | | | | |
| Southern Company Gas Capital | $ 733 | 1.09% | $ 461 | 0.79% | $ 770 |
| Nicor Gas | 524 | 0.95% | 309 | 0.67% | 587 |
| Total | $ 1,257 | 1.03% | $ 770 | 0.74% | |
| Predecessor – December 31, 2015: | | | | | |
| Southern Company Gas Capital | $ 471 | 0.71% | $ 382 | 0.49% | $ 787 |
| Nicor Gas | 539 | 0.52% | 349 | 0.38% | 585 |
| Total | $ 1,010 | 0.60% | $ 731 | 0.44% | |

(*) Average and maximum amounts are based upon daily balances during the 12-month periods.

The Company believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and operating cash flows.

Additionally, Pivotal Utility Holdings is party to a series of loan agreements with the New Jersey Economic Development Authority and Brevard County, Florida under which five series of gas facility revenue bonds totaling $200 million have been issued. The Elizabethtown Gas asset sale agreement requires that bonds representing $180 million of the total that are currently eligible for redemption at par be redeemed on or prior to consummation of the sale.

**Financing Activities**

The long-term debt on the Company's balance sheets includes both principal and non-principal components. As of December 31, 2017 , the non-principal components totaled $508 million , including the amount attributable to long-term debt due within one year, which consisted of the unamortized portions of the fair value adjustment recorded in purchase accounting, debt premiums, debt discounts, and debt issuance costs.

In December 2016, the Company executed intercompany promissory notes to further allocate interest expense to its reportable segments that previously remained in the "all other" segment. These intercompany promissory notes allow the Company to calculate net income, which is its performance measure subsequent to the Merger, at the segment level that incorporates the full impact of interest costs.

In May 2017, Southern Company Gas Capital issued $450 million aggregate principal amount of Series 2017A 4.40% Senior Notes due May 30, 2047. The proceeds were used to repay the Company's short-term indebtedness and for general corporate purposes.

In July 2017, Atlanta Gas Light repaid at maturity $22 million of Series C medium-term notes.

On August 10, 2017, Nicor Gas issued $100 million aggregate principal amount of First Mortgage Bonds 3.03% Series due August 10, 2027 and $100 million aggregate principal amount of First Mortgage Bonds 3.62% Series due August 10, 2037. On November 1, 2017, Nicor Gas issued $100 million aggregate principal amount of First Mortgage Bonds 3.85% Series due August 10, 2047 and $100 million aggregate principal amount of First Mortgage Bonds 4.00% Series due August 10, 2057. The proceeds were used to repay short-term indebtedness incurred under the Nicor Gas commercial paper program and for other working capital needs.

On January 4, 2018, the Company issued a floating rate promissory note to Southern Company, in an aggregate principal amount of $100 million due July 31, 2018 bearing interest based on one-month LIBOR, to support the current activities of wholesale gas services.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

**Credit Rating Risk**

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change below BBB- and/or Baa3. These contracts are for physical gas purchases and sales and energy price risk management. The maximum potential collateral requirement under these contracts at December 31, 2017 was $10 million .

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact the ability of the Company to access capital markets and would be likely to impact the cost at which it does so.

On March 24, 2017, S&P revised its consolidated credit rating outlook for Southern Company and its subsidiaries (including the Company, Southern Company Gas Capital, and Nicor Gas) from stable to negative.

While it is unclear how the credit rating agencies and the relevant state regulatory bodies may respond to the Tax Reform Legislation, certain financial metrics, such as the funds from operations to debt percentage, used by the credit rating agencies to assess Southern Company and its subsidiaries, including the Company, may be negatively impacted. Absent actions by Southern Company and its subsidiaries, including the Company, to mitigate the resulting impacts, which, among other alternatives, could include adjusting capital structure and/or monetizing regulatory assets, the Company's, Southern Company Gas Capital's, and Nicor Gas' credit ratings could be negatively affected. See Note 3 to the financial statements for additional information.

**Market Price Risk**

The Company is exposed to market risks, primarily commodity price risk, interest rate risk, and weather risk. Due to various cost recovery mechanisms, the natural gas distribution utilities of the Company that sell natural gas directly to end-use customers have limited exposure to market volatility of natural gas prices. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company uses derivatives to buy and sell natural gas as well as for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives designated as hedges. The weighted average interest rate on $200 million of long-term variable interest rate exposure at December 31, 2017 was 1.71% . If the Company sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would have an immaterial effect on annualized interest expense at December 31, 2017. See Note 1 to the financial statements under " Financial Instruments " and Note 10 to the financial statements for additional information.

Certain natural gas distribution utilities of the Company manage fuel-hedging programs implemented per the guidelines of their respective state regulatory agencies to hedge the impact of market fluctuations in natural gas prices for customers. For the weather risk associated with Nicor Gas, the Company has a corporate weather hedging program that utilizes weather derivatives to reduce the risk of lower adjusted operating margins potentially resulting from significantly warmer-than-normal weather. In addition, certain non-regulated operations routinely utilize various types of derivative instruments to economically hedge certain commodity price and weather risks inherent in the natural gas industry. These instruments include a variety of exchange-traded and over-the-counter (OTC) energy contracts, such as forward contracts, futures contracts, options contracts, and swap agreements. Gas marketing services and wholesale gas services also actively manage storage positions through a variety of hedging transactions for the purpose of managing exposures arising from changing natural gas prices. These hedging instruments are used to substantially protect economic margins (as spreads between wholesale and retail natural gas prices widen between periods) and thereby minimize exposure to declining operating margins. Some of these economic hedge activities may not qualify, or are not designated, for hedge accounting treatment. The Company had no material change in market risk exposure for the year ended December 31, 2017 when compared to the year ended December 31, 2016.

For the periods presented below, the changes in net fair value of derivative contracts were as follows:

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | **Year Ended December 31, 2017** | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | Year Ended December 31, 2015 |
| | *(in millions)* | | *(in millions)* | |
| Contracts outstanding at beginning of period, assets (liabilities), net | **$ 8** | $ (54) | $ 75 | $ 61 |
| Contracts realized or otherwise settled | **(1)** | 18 | (77) | (17) |
| Current period changes [(a)] | **(113)** | 48 | (82) | 32 |
| Contracts outstanding at end of period, assets (liabilities), net | **(106)** | 12 | (84) | 76 |
| Netting of cash collateral | **193** | 62 | 120 | 96 |
| Cash collateral and net fair value of contracts outstanding at end of period [(b)] | **$ 87** | $ 74 | $ 36 | $ 172 |

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

(b) Net fair value of derivative contracts outstanding excludes premium and intrinsic value associated with weather derivatives of $11 million at December 31, 2017 and includes premium and intrinsic value associated with weather derivatives of $4 million at December 31, 2016 , $5 million at June 30, 2016, and $10 million at December 31, 2015 .

The net hedge volume of energy-related derivative contracts for natural gas positions for the years ended December 31 were as follows:

| | **2017** | 2016 |
|---|---|---|
| | mmBtu Volume | |
| | *(in millions)* | |
| Commodity – Natural gas | **300** | 157 |
| Net Purchased/(Sold) Volume | **300** | 157 |

The Company's derivative contracts are comprised of both long and short natural gas positions. A long position is a contract to purchase natural gas, and a short position is a contract to sell natural gas. The volume presented above represents the net of long natural gas positions of 3.51 billion mmBtu and short natural gas positions of 3.21 billion mmBtu at December 31, 2017 and the net of long natural gas positions of 3.31 billion mmBtu and short natural gas positions of 3.16 billion mmBtu at December 31, 2016 .

Energy-related derivative contracts that are designated as regulatory hedges relate primarily to the Company's fuel-hedging programs. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in cost of natural gas as the underlying gas is used in operations and ultimately recovered through the respective cost recovery clause. Certain other gains and losses on energy-related derivatives, designated as cash flow hedges (which are mainly used to hedge anticipated purchases and sales), are initially deferred in OCI before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the natural gas industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

The Company uses OTC contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2 of the fair value hierarchy. See Note 9 to the financial statements for further discussion of fair value measurements.

The maturities of the energy-related derivative contracts at December 31, 2017 were as follows:

| | | Fair Value Measurements December 31, 2017 | | |
|---|---|---|---|---|
| | | Maturity | | |
| | **Total Fair Value** | **Year 1** | **Years 2 & 3** | **Years 4 & 5** |
| | | *(in millions)* | | |
| Level 1 [(a)] | **$ (148)** | **$ (71)** | **$ (59)** | **$ (18)** |
| Level 2 [(b)] | **42** | **10** | **30** | **2** |
| Fair value of contracts outstanding at end of period [(c)] | **$ (106)** | **$ (61)** | **$ (29)** | **$ (16)** |

(a) Valued using NYMEX futures prices.

(b) Valued using basis transactions that represent the cost to transport natural gas from a NYMEX delivery point to the contract delivery point. These transactions are based on quotes obtained either through electronic trading platforms or directly from brokers.

(c) Excludes cash collateral of $193 million as well as premium and associated intrinsic value associated with weather derivatives of $11 million at December 31, 2017 .

### *Value at Risk (VaR)*

VaR is the maximum potential loss in portfolio value over a specified time period that is not expected to be exceeded within a given degree of probability. The Company's VaR may not be comparable to that of other companies due to differences in the factors used to calculate VaR. The Company's VaR is determined on a 95% confidence interval and a one-day holding period, which means that 95% of the time, the risk of loss in a day from a portfolio of positions is expected to be less than or equal to the amount of VaR calculated. The open exposure of the Company is managed in accordance with established policies that limit market risk and require daily reporting of potential financial exposure to senior management. Because the Company generally manages physical gas assets and economically protects its positions by hedging in the futures markets, the Company's open exposure is generally mitigated. The Company employs daily risk testing, using both VaR and stress testing, to evaluate the risk of its positions.

The Company actively monitors open commodity positions and the resulting VaR and maintains a relatively small risk exposure as total buy volume is close to sell volume, with minimal open natural gas price risk. Based on a 95% confidence interval and employing a one-day holding period, SouthStar's portfolio of positions for all periods presented was immaterial.

For the periods presented below, wholesale gas services had the following VaRs:

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | **Year Ended December 31, 2017** | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | Year Ended December 31, 2015 |
| | *(in millions)* | | *(in millions)* | |
| Period end (*) | **$ 4.8** | $ 2.3 | $ 1.9 | $ 2.4 |
| Average | **2.0** | 2.0 | 2.0 | 3.0 |
| High (*) | **4.8** | 2.8 | 2.5 | 7.3 |
| Low | **1.0** | 1.4 | 1.6 | 1.6 |

(*) Increase in VaR at December 31, 2017 was driven by significant natural gas price increases in Sequent's key markets due to colder-than-normal weather. As weather moderated during January 2018, VaR reduced to a level consistent with prior periods.

**Credit Risk**

*Gas Distribution Operations*

Concentration of credit risk occurs at Atlanta Gas Light for amounts billed for services and other costs to its customers, which consist of 15 Marketers in Georgia. The credit risk exposure to Marketers varies seasonally, with the lowest exposure in the non-peak summer months and the highest exposure in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. The functions of the retail sale of gas include the purchase and sale of natural gas, customer service, billings, and collections. The provisions of Atlanta Gas Light's tariff allow Atlanta Gas Light to obtain credit security support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill from Atlanta Gas Light. For 2017 , the four largest Marketers based on customer count accounted for 19% of the Company's adjusted operating margin and 22% of gas distribution operations' adjusted operating margin.

Several factors are designed to mitigate the Company's risks from the increased concentration of credit that has resulted from deregulation. In addition to the security support described above, Atlanta Gas Light bills intrastate delivery service to Marketers in advance rather than in arrears. Atlanta Gas Light accepts credit support in the form of cash deposits, letters of credit/surety bonds from acceptable issuers, and corporate guarantees from investment-grade entities. On a monthly basis, the Risk Management Committee reviews the adequacy of credit support coverage, credit rating profiles of credit support providers, and payment status of each Marketer. The Company believes that adequate policies and procedures are in place to properly quantify, manage, and report on Atlanta Gas Light's credit risk exposure to Marketers.

Atlanta Gas Light also faces potential credit risk in connection with assignments of interstate pipeline transportation and storage capacity to Marketers. Although Atlanta Gas Light assigns this capacity to Marketers, in the event that a Marketer fails to pay the interstate pipelines for the capacity, the interstate pipelines would likely seek repayment from Atlanta Gas Light.

*Gas Marketing Services*

The Company obtains credit scores for its firm residential and small commercial customers using a national credit reporting agency, enrolling only those customers that meet or exceed the Company's credit threshold. The Company considers potential interruptible and large commercial customers based on reviews of publicly available financial statements and commercially available credit reports. Prior to entering into a physical transaction, the Company also assigns physical wholesale counterparties an internal credit rating and credit limit based on the counterparties' Moody's, S&P, and Fitch ratings, commercially available credit reports, and audited financial statements.

*Wholesale Gas Services*

The Company has established credit policies to determine and monitor the creditworthiness of counterparties, as well as the quality of pledged collateral. The Company also utilizes master netting agreements whenever possible to mitigate exposure to counterparty credit risk. When the Company is engaged in more than one outstanding derivative transaction with the same counterparty and also has a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of the Company's credit risk. The Company also uses other netting agreements with certain counterparties with whom it conducts significant transactions. Master netting agreements enable the Company to net certain assets and liabilities by counterparty. The Company also nets across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions.

The Company may require counterparties to pledge additional collateral when deemed necessary. The Company conducts credit evaluations and obtains appropriate internal approvals for a counterparty's line of credit before any transaction with the counterparty is executed. In most cases, the counterparty must have an investment grade rating, which includes a minimum long-term debt rating of Baa3 from Moody's and BBB- from S&P. Generally, the Company requires credit enhancements by way of a guaranty, cash deposit, or letter of credit for transaction counterparties that do not have investment grade ratings.

Certain of the Company's derivative instruments contain credit-risk-related or other contingent features that could increase the payments for collateral it posts in the normal course of business when its financial instruments are in net liability positions. At December 31, 2017 , for agreements with such features, the Company's derivative instruments with liability fair values totaled $1 million for which the Company had no collateral posted with derivatives counterparties to satisfy these arrangements.

The Company has a concentration of credit risk as measured by its 30-day receivable exposure plus forward exposure. At December 31, 2017 , wholesale gas services' top 20 counterparties represented approximately 48% , or $203 million , of its total counterparty exposure and had a weighted average S&P equivalent credit rating of A-, all of which is consistent with the prior year. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P or Moody's ratings to an internal rating ranging from 9 to 1, with 9 being equivalent to AAA/Aaa by S&P and Moody's, respectively, and 1 being D / Default by S&P and Moody's, respectively. A counterparty that does not have an external rating is assigned an internal rating based on the strength of the financial ratios of that counterparty. To arrive at the weighted average credit rating, each counterparty is assigned an internal ratio, which is multiplied by their credit exposure and summed for all counterparties. The sum is divided by the aggregate total counterparties' exposures, and this numeric value is then converted to an S&P equivalent.

The following table provides credit risk information related to the Company's third-party natural gas contracts receivable and payable positions at December 31:

| | Gross Receivables | | Gross Payables | |
|---|---|---|---|---|
| | **2017** | 2016 | **2017** | 2016 |
| | *(in millions)* | | *(in millions)* | |
| Netting agreements in place: | | | | |
| Counterparty is investment grade | **$ 342** | $ 375 | **$ 202** | $ 227 |
| Counterparty is non-investment grade | **20** | 14 | **25** | 31 |
| Counterparty has no external rating | **226** | 223 | **315** | 339 |
| No netting agreements in place: | | | | |
| Counterparty is investment grade | **19** | 11 | **4** | — |
| Amount recorded in balance sheets | **$ 607** | $ 623 | **$ 546** | $ 597 |

**Capital Requirements and Contractual Obligations**

The Company's capital investments are currently estimated to total $1.7 billion for 2018 , $1.7 billion for 2019 , $1.5 billion for 2020 , $1.2 billion for 2021 , and $1.4 billion for 2022 . The Company's capital investments include estimated capital expenditures related to Elizabethtown Gas and Elkton Gas of $123 million for 2018 , $125 million for 2019 , $124 million for 2020 , $126 million for 2021 , and $129 million for 2022 . See Note 11 to the financial statements under "Proposed Sale of Elizabethtown Gas and Elkton Gas" for additional information. The regulatory infrastructure programs and other construction programs are subject to periodic review and revision, and actual costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in FERC rules and regulations; state regulatory agency approvals; changes in legislation; the cost and efficiency of labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to certain eligible employees and funds trusts to the extent required by the applicable state regulatory agencies.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, including the related interest; pipeline charges, storage capacity, and gas supply; operating leases; asset management agreements; financial derivative obligations; pension and other postretirement benefit plans; and other purchase commitments, primarily related to environmental remediation liabilities, are detailed in the contractual obligations table that follows. See Notes 3 , 6 , 7 , and 11 to the financial statements for additional information.

**Contractual Obligations**

Contractual obligations at December 31, 2017 were as follows:

| | 2018 | 2019-2020 | 2021-2022 | After 2022 | Total |
|---|---|---|---|---|---|
| | | | *(in millions)* | | |
| Long-term debt [(a)] — | | | | | |
| Principal | $ 155 | $ 350 | $ 423 | $ 4,612 | $ 5,540 |
| Interest | 241 | 452 | 421 | 3,137 | 4,251 |
| Pipeline charges, storage capacity, and gas supply [(b)] | 813 | 968 | 714 | 2,294 | 4,789 |
| Operating leases [(c)] | 17 | 32 | 28 | 26 | 103 |
| Asset management agreements [(d)] | 9 | 6 | — | — | 15 |
| Financial derivative obligations [(e)] | 444 | 174 | 37 | 5 | 660 |
| Pension and other postretirement benefit plans [(f)] | 13 | 28 | — | — | 41 |
| Purchase commitments — | | | | | |
| Capital [(g)] | 1,821 | 2,979 | 2,662 | — | 7,462 |
| Other [(h)] | 31 | 7 | 2 | 1 | 41 |
| Total | $ 3,544 | $ 4,996 | $ 4,287 | $ 10,075 | $ 22,902 |

(a) Amounts are reflected based on final maturity dates. The Company plans to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates at December 31, 2017, as reflected in the statements of capitalization.

(b) Includes charges recoverable through a natural gas cost recovery mechanism, or alternatively billed to Marketers, and demand charges associated with Sequent. The gas supply balance includes amounts for Nicor Gas and SouthStar gas commodity purchase commitments of 35 million mmBtu at floating gas prices calculated using forward natural gas prices at December 31, 2017 and valued at $101 million. The Company provides guarantees to certain gas suppliers for certain of its subsidiaries, including SouthStar, in support of payment obligations.

(c) Certain operating leases have provisions for step rent or escalation payments and certain lease concessions are accounted for by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms. However, this accounting treatment does not affect the future annual operating lease cash obligations as shown herein. In terms of rental charges and duration of contracts, the Company's most significant operating leases relate to real estate.

(d) Represent fixed-fee minimum payments for Sequent's affiliated asset management agreements.

(e) See Notes 1 and 10 to the financial statements for additional information.

(f) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

(g) Estimated capital expenditures are provided through 2022. Capital includes amounts related to Elizabethtown Gas and Elkton Gas, which represent $123 million in 2018, $249 million in 2019-2020, and $255 million in 2021-2022. See Note 11 to the financial statements under "Proposed Sale of Elizabethtown Gas and Elkton Gas" for additional information. Capital also includes amounts related to the Company's pipeline investments that will be recorded at the joint venture level, which represent $64 million in 2018, $195 million in 2019-2020, and less than $1 million in capital expenditures in 2021-2022.

(h) Includes contractual environmental remediation liabilities that are generally recoverable through base rates or rate rider mechanisms and long-term service agreements.

**Cautionary Statement Regarding Forward-Looking Statements**

The Company's 2017 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning regulatory matters, the strategic goals for the Company, economic conditions, natural gas price volatility, derivative losses, regulatory and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, pending or potential litigation matters, access to sources of capital, projections for the qualified pension plan contributions, financing activities, completion dates of construction projects, completion of announced acquisitions or dispositions, filings with state and federal regulatory authorities, impacts of the Tax Reform Legislation, and estimated other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including environmental laws and regulations governing air, water, land, and protection of other natural resources , and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- the uncertainty surrounding the recently enacted Tax Reform Legislation, including implementing regulations and IRS interpretations, actions that may be taken in response by regulatory authorities, and its impact, if any, on the credit ratings of the Company, Southern Company Gas Capital, and Nicor Gas;
- current and future litigation or regulatory investigations, proceedings, or inquiries ;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for natural gas, including those relating to weather, the general economy, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of natural gas;
- limits on pipeline capacity;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of facilities;
- investment performance of the Company's employee and retiree benefit plans ;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to natural gas and other cost recovery mechanisms;
- the inherent risks involved in transporting and storing natural gas;
- the ability to successfully operate the natural gas distribution and storage facilities and the successful performance of necessary corporate functions;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, including the proposed disposition of Elizabethtown Gas and Elkton Gas, which cannot be assured to be completed or beneficial to the Company;
- the possibility that the anticipated benefits from the Merger cannot be fully realized or may take longer to realize than expected and the possibility that costs related to integration with Southern Company will be greater than expected;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or physical attack and the threat of physical attacks;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's, Southern Company Gas Capital's, and Nicor Gas' credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on foreign currency exchange rates, counterparty performance, and the economy in general ;

- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. natural gas pipeline infrastructure or operation of storage resources;
- impairments of goodwill or long-lived assets;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports filed by the Company from time to time with the SEC.

**The Company expressly disclaims any obligation to update any forward-looking statements.**

**CONSOLIDATED STATEMENTS OF INCOME**
**Southern Company Gas and Subsidiary Companies 2017 Annual Report**

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | **For the year ended December 31, 2017** | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | For the year ended December 31, 2015 |
| | *(in millions)* | | *(in millions)* | |
| **Operating Revenues:** | | | | |
| Natural gas revenues (includes revenue taxes of $100, $32, $57, and $103 for the periods presented, respectively) | **$ 3,791** | $ 1,596 | $ 1,841 | $ 3,817 |
| Other revenues | **129** | 56 | 64 | 124 |
| Total operating revenues | **3,920** | 1,652 | 1,905 | 3,941 |
| **Operating Expenses:** | | | | |
| Cost of natural gas | **1,601** | 613 | 755 | 1,617 |
| Cost of other sales | **29** | 10 | 14 | 28 |
| Other operations and maintenance | **940** | 482 | 454 | 928 |
| Depreciation and amortization | **501** | 238 | 206 | 397 |
| Taxes other than income taxes | **184** | 71 | 99 | 181 |
| Merger-related expenses | **—** | 41 | 56 | 44 |
| Total operating expenses | **3,255** | 1,455 | 1,584 | 3,195 |
| **Operating Income** | **665** | 197 | 321 | 746 |
| **Other Income and (Expense):** | | | | |
| Earnings from equity method investments | **106** | 60 | 2 | 6 |
| Interest expense, net of amounts capitalized | **(200)** | (81) | (96) | (175) |
| Other income (expense), net | **39** | 14 | 5 | 9 |
| Total other income and (expense) | **(55)** | (7) | (89) | (160) |
| **Earnings Before Income Taxes** | **610** | 190 | 232 | 586 |
| Income taxes | **367** | 76 | 87 | 213 |
| **Net Income** | **243** | 114 | 145 | 373 |
| Less: Net income attributable to noncontrolling interest | **—** | — | 14 | 20 |
| **Net Income Attributable to Southern Company Gas** | **$ 243** | $ 114 | $ 131 | $ 353 |

The accompanying notes are an integral part of these consolidated financial statements.

**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**
**Southern Company Gas and Subsidiary Companies 2017 Annual Report**

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | **For the year ended December 31, 2017** | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | For the year ended December 31, 2015 |
| | *(in millions)* | | *(in millions)* | |
| **Net Income** | **$ 243** | $ 114 | $ 145 | $ 373 |
| Other comprehensive income (loss): | | | | |
| Qualifying hedges: | | | | |
| Changes in fair value, net of tax of $(3), $(1), $(23), and $(3), respectively | **(5)** | (1) | (41) | — |
| Reclassification adjustment for amounts included in net income, net of tax of $-, $-, $-, and $1, respectively | **1** | — | 1 | 8 |
| Pension and other postretirement benefit plans: | | | | |
| Benefit plan net gain (loss), net of tax of $-, $19, $-, and $-, respectively | **(1)** | 27 | — | — |
| Reclassification adjustment for amounts included in net income, net of tax of $-, $-, $4, and $9, respectively | **—** | — | 5 | 12 |
| **Total other comprehensive income (loss)** | **(5)** | 26 | (35) | 20 |
| Less: Comprehensive income attributable to noncontrolling interest | **—** | — | 14 | 20 |
| **Comprehensive Income Attributable to Southern Company Gas** | **$ 238** | $ 140 | $ 96 | $ 373 |

The accompanying notes are an integral part of these consolidated financial statements.

**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**Southern Company Gas and Subsidiary Companies 2017 Annual Report**

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | **For the year ended December 31, 2017** | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | For the year ended December 31, 2015 |
| | *(in millions)* | | *(in millions)* | |
| **Operating Activities:** | | | | |
| Net income | **$ 243** | $ 114 | $ 145 | $ 373 |
| Adjustments to reconcile net income to net cash provided from (used for) operating activities — | | | | |
| Depreciation and amortization, total | **501** | 238 | 206 | 397 |
| Deferred income taxes | **236** | 92 | 8 | 211 |
| Pension, postretirement, and other employee benefits | **(1)** | 6 | 5 | 24 |
| Pension and postretirement funding | **—** | (125) | — | — |
| Stock based compensation expense | **32** | 20 | 20 | 34 |
| Hedge settlements | **—** | (35) | (26) | — |
| Goodwill impairment | **—** | — | — | 14 |
| Mark-to-market adjustments | **(24)** | (3) | 162 | 22 |
| Other, net | **(83)** | (78) | (82) | 43 |
| Changes in certain current assets and liabilities — | | | | |
| -Receivables | **(91)** | (490) | 181 | 615 |
| -Natural gas for sale, net of temporary LIFO liquidation | **36** | (226) | 273 | 72 |
| -Prepaid income taxes | **(39)** | (23) | 151 | 23 |
| -Other current assets | **(24)** | (31) | 37 | (11) |
| -Accounts payable | **(20)** | 194 | 43 | (434) |
| -Accrued taxes | **110** | 8 | 41 | (20) |
| -Accrued compensation | **15** | (13) | (21) | (6) |
| -Other current liabilities | **(8)** | 24 | (30) | 24 |
| Net cash provided from (used for) operating activities | **883** | (328) | 1,113 | 1,381 |
| **Investing Activities:** | | | | |
| Property additions | **(1,514)** | (614) | (509) | (961) |
| Cost of removal, net of salvage | **(66)** | (40) | (32) | (84) |
| Change in construction payables, net | **72** | 22 | (7) | 18 |
| Investment in unconsolidated subsidiaries | **(145)** | (1,444) | (14) | (12) |
| Returned investment in unconsolidated subsidiaries | **80** | 5 | 3 | 12 |
| Other investing activities | **3** | 4 | — | — |
| Net cash used for investing activities | **(1,570)** | (2,067) | (559) | (1,027) |
| **Financing Activities:** | | | | |
| Increase (decrease) in notes payable, net | **262** | 1,143 | (896) | (165) |
| Proceeds — | | | | |
| First mortgage bonds | **400** | — | 250 | — |
| Capital contributions from parent company | **103** | 1,085 | — | — |
| Senior notes | **450** | 900 | 350 | 250 |
| Redemptions and repurchases — | | | | |
| Medium-term notes | **(22)** | — | — | — |
| First mortgage bonds | **—** | — | (125) | — |
| Senior notes | **—** | (420) | — | (200) |
| Distribution to noncontrolling interest | **—** | (15) | (19) | (18) |
| Purchase of 15% noncontrolling interest in SouthStar | **—** | (160) | — | — |
| Payment of common stock dividends | **(443)** | (126) | (128) | (244) |
| Other financing activities | **(9)** | (8) | 10 | 11 |
| Net cash provided from (used for) financing activities | **741** | 2,399 | (558) | (366) |

| | | | | |
|---|---|---|---|---|
| **Net Change in Cash and Cash Equivalents** | **54** | 4 | (4) | (12) |
| **Cash and Cash Equivalents at Beginning of Period** | **19** | 15 | 19 | 31 |
| **Cash and Cash Equivalents at End of Period** | **$ 73** | $ 19 | $ 15 | $ 19 |

The accompanying notes are an integral part of these consolidated financial statements.

**CONSOLIDATED BALANCE SHEETS**
**At December 31, 2017 and 2016**
**Southern Company Gas and Subsidiary Companies 2017 Annual Report**

| **Assets** | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Current Assets:** | | |
| Cash and cash equivalents | **$ 73** | $ 19 |
| Receivables — | | |
| Energy marketing receivable | **607** | 623 |
| Customer accounts receivable | **400** | 364 |
| Unbilled revenues | **285** | 239 |
| Other accounts and notes receivable | **103** | 76 |
| Accumulated provision for uncollectible accounts | **(28)** | (27) |
| Materials and supplies | **24** | 26 |
| Natural gas for sale | **595** | 631 |
| Prepaid income taxes | **26** | 24 |
| Prepaid expenses | **53** | 55 |
| Assets from risk management activities, net of collateral | **135** | 128 |
| Other regulatory assets, current | **94** | 81 |
| Other current assets | **28** | 11 |
| Total current assets | **2,395** | 2,250 |
| **Property, Plant, and Equipment:** | | |
| In service | **15,833** | 14,508 |
| Less: Accumulated depreciation | **4,596** | 4,439 |
| Plant in service, net of depreciation | **11,237** | 10,069 |
| Construction work in progress | **491** | 496 |
| Total property, plant, and equipment | **11,728** | 10,565 |
| **Other Property and Investments:** | | |
| Goodwill | **5,967** | 5,967 |
| Equity investments in unconsolidated subsidiaries | **1,477** | 1,541 |
| Other intangible assets, net of amortization of $120 and $34 at December 31, 2017 and December 31, 2016, respectively | **280** | 366 |
| Miscellaneous property and investments | **21** | 21 |
| Total other property and investments | **7,745** | 7,895 |
| **Deferred Charges and Other Assets:** | | |
| Other regulatory assets, deferred | **901** | 973 |
| Other deferred charges and assets | **218** | 170 |
| Total deferred charges and other assets | **1,119** | 1,143 |
| **Total Assets** | **$ 22,987** | $ 21,853 |

The accompanying notes are an integral part of these consolidated financial statements.

**CONSOLIDATED BALANCE SHEETS**
**At December 31, 2017 and 2016**
**Southern Company Gas and Subsidiary Companies 2017 Annual Report**

| **Liabilities and Stockholder's Equity** | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| **Current Liabilities:** | | |
| Securities due within one year | **$ 157** | $ 22 |
| Notes payable | **1,518** | 1,257 |
| Energy marketing trade payables | **546** | 597 |
| Accounts payable | **446** | 348 |
| Customer deposits | **128** | 153 |
| Accrued taxes — | | |
| Accrued income taxes | **40** | 26 |
| Other accrued taxes | **78** | 68 |
| Accrued interest | **51** | 48 |
| Accrued compensation | **74** | 58 |
| Liabilities from risk management activities, net of collateral | **69** | 62 |
| Other regulatory liabilities, current | **135** | 102 |
| Accrued environmental remediation, current | **46** | 69 |
| Other current liabilities | **113** | 108 |
| Total current liabilities | **3,401** | 2,918 |
| **Long-term Debt** (See accompanying statements) | **5,891** | 5,259 |
| **Deferred Credits and Other Liabilities:** | | |
| Accumulated deferred income taxes | **1,089** | 1,975 |
| Deferred credits related to income taxes | **1,063** | 22 |
| Employee benefit obligations | **415** | 441 |
| Other cost of removal obligations | **1,646** | 1,616 |
| Accrued environmental remediation, deferred | **342** | 357 |
| Other regulatory liabilities, deferred | **30** | 29 |
| Other deferred credits and liabilities | **88** | 127 |
| Total deferred credits and other liabilities | **4,673** | 4,567 |
| **Total Liabilities** | **13,965** | 12,744 |
| **Common Stockholder's Equity** (See accompanying statements) | **9,022** | 9,109 |
| **Total Liabilities and Stockholder's Equity** | **$ 22,987** | $ 21,853 |
| **Commitments and Contingent Matters** (See notes) | | |

The accompanying notes are an integral part of these consolidated financial statements.

**CONSOLIDATED STATEMENTS OF CAPITALIZATION**
**At December 31, 2017 and 2016**
**Southern Company Gas and Subsidiary Companies 2017 Annual Report**

| | 2017 | 2016 | 2017 | 2016 |
|---|---|---|---|---|
| | *(in millions)* | | *(percent of total)* | |
| **Long-Term Debt:** | | | | |
| Long-term notes payable — | | | | |
| 7.20% due 2017 | $ — | $ 22 | | |
| 3.50% due 2018 | 155 | 155 | | |
| 5.25% due 2019 | 300 | 300 | | |
| 3.50% to 9.10% due 2021 | 330 | 330 | | |
| 8.55% to 8.70% due 2022 | 46 | 46 | | |
| 2.45% to 7.30% due 2023-2047 | 3,484 | 3,034 | | |
| Total long-term notes payable | 4,315 | 3,887 | | |
| Other long-term debt — | | | | |
| First mortgage bonds — | | | | |
| 4.70% due 2019 | 50 | 50 | | |
| 2.66% to 6.58% due 2023-2057 | 975 | 575 | | |
| Gas facility revenue bonds — | | | | |
| Variable rate (1.71% at 12/31/17) due 2022 | 47 | 47 | | |
| Variable rate (1.71% at 12/31/17) due 2024-2033 | 153 | 153 | | |
| Total other long-term debt | 1,225 | 825 | | |
| Unamortized fair value adjustment of long-term debt | 525 | 578 | | |
| Unamortized debt discount | (17) | (9) | | |
| Total long-term debt (annual interest requirement — $241 million) | 6,048 | 5,281 | | |
| Less amount due within one year | 157 | 22 | | |
| Long-term debt excluding amount due within one year | 5,891 | 5,259 | 39.5% | 36.6% |
| **Common Stockholder's Equity:** | | | | |
| Common stock — par value $0.01 per share | | | | |
| Authorized — 100 million shares | | | | |
| Outstanding — 100 shares | | | | |
| Paid-in capital | 9,214 | 9,095 | | |
| Accumulated deficit | (212) | (12) | | |
| Accumulated other comprehensive income | 20 | 26 | | |
| Total common stockholder's equity | 9,022 | 9,109 | 60.5 | 63.4 |
| **Total Capitalization** | $ 14,913 | $ 14,368 | 100.0% | 100.0% |

The accompanying notes are an integral part of these financial statements.

## CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
**Southern Company Gas and Subsidiary Companies 2017 Annual Report**

| | Southern Company Gas Common Stockholders' Equity | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Number of Common Shares | | Common Stock | | | | | | |
| | Issued | Treasury | Par Value | Paid-In Capital | Treasury | Retained Earnings (Accumulated Deficit) | Accumulated Other Comprehensive Income (Loss) | Noncontrolling Interests | Total |
| | *(in thousands)* | | *(in millions)* | | | | | | |
| **Predecessor – Balance at December 31, 2014** | 119,647 | 217 | $ 599 | $ 2,087 | $ (8) | $ 1,312 | $ (206) | $ 44 | $3,828 |
| Consolidated net income attributable to Southern Company Gas | — | — | — | — | — | 353 | — | — | 353 |
| Other comprehensive income (loss) | — | — | — | — | — | — | 20 | — | 20 |
| Stock issued | 221 | — | 1 | 11 | — | — | — | — | 12 |
| Stock-based compensation | 509 | — | 3 | 1 | — | — | — | — | 4 |
| Cash dividends on common stock | — | — | — | — | — | (244) | — | — | (244) |
| Distribution to noncontrolling interest (*) | — | — | — | — | — | — | — | (18) | (18) |
| Net income attributable to noncontrolling interest (*) | — | — | — | — | — | — | — | 20 | 20 |
| **Predecessor – Balance at December 31, 2015** | 120,377 | 217 | 603 | 2,099 | (8) | 1,421 | (186) | 46 | 3,975 |
| Consolidated net income attributable to Southern Company Gas | — | — | — | — | — | 131 | — | — | 131 |
| Other comprehensive income (loss) | — | — | — | — | — | — | (35) | — | (35) |
| Stock issued | 95 | — | — | 6 | — | — | — | — | 6 |
| Stock-based compensation | 270 | — | 2 | 28 | — | — | — | — | 30 |
| Cash dividends on common stock | — | — | — | — | — | (128) | — | — | (128) |
| Reclassification of noncontrolling interest (*) | — | — | — | — | — | — | — | (46) | (46) |
| **Predecessor – Balance at June 30, 2016** | 120,742 | 217 | 605 | 2,133 | (8) | 1,424 | (221) | — | 3,933 |
| **Successor – Balance at July 1, 2016** | — | — | — | 8,001 | — | — | — | — | 8,001 |
| Consolidated net income attributable to Southern Company Gas | — | — | — | — | — | 114 | — | — | 114 |
| Capital contributions from parent company | — | — | — | 1,094 | — | — | — | — | 1,094 |
| Other comprehensive income (loss) | — | — | — | — | — | — | 26 | — | 26 |
| Cash dividends on common stock | — | — | — | — | — | (126) | — | — | (126) |
| **Successor – Balance at December 31, 2016** | **—** | **—** | **—** | **9,095** | **—** | **(12)** | **26** | **—** | **9,109** |
| Consolidated net income attributable to Southern Company Gas | **—** | **—** | **—** | **—** | **—** | **243** | **—** | **—** | **243** |
| Capital contributions from parent company, net | **—** | **—** | **—** | **117** | **—** | **—** | **—** | **—** | **117** |
| Other comprehensive income (loss) | **—** | **—** | | **—** | **—** | **—** | **(5)** | **—** | **(5)** |
| Cash dividends on common stock | **—** | **—** | **—** | **—** | **—** | **(443)** | **—** | **—** | **(443)** |
| Other | **—** | **—** | **—** | **2** | **—** | **—** | **(1)** | **—** | **1** |
| **Successor – Balance at December 31, 2017** | **—** | **—** | **$ —** | **$ 9,214** | **$ —** | **$ (212)** | **$ 20** | **$ —** | **$9,022** |

(*) Associated with SouthStar. See Note 4 to the financial statements for additional information.

The accompanying notes are an integral part of these consolidated financial statements.

**NOTES TO FINANCIAL STATEMENTS**
**Southern Company Gas and Subsidiary Companies 2017 Annual Report**

**Index to the Notes to Financial Statements**

## 1 . SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

### General

On July 1, 2016, Southern Company and Southern Company Gas (together with its subsidiaries, the Company) completed the Merger and Southern Company Gas became a wholly-owned, direct subsidiary of Southern Company. In addition to the Company, Southern Company is the parent company of four traditional electric operating companies, Southern Power, SCS, Southern Linc, Southern Holdings, Southern Nuclear, PowerSecure, Inc., and other direct and indirect subsidiaries. The Company is an energy services holding company whose primary business is the distribution of natural gas across seven states through its seven natural gas distribution utilities. The Company also is involved in several other businesses that are complementary to the distribution of natural gas. The traditional electric operating companies – Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company – are vertically integrated utilities providing electric service in four Southeastern states. Southern Power develops, constructs, acquires, owns, and manages power generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. Southern Linc provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber optics services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases and for other electric services. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants. PowerSecure, Inc. is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure.

The financial statements reflect the Company's investments in its subsidiaries on a consolidated basis. The equity method is used for subsidiaries in which the Company has significant influence but does not control and for VIEs where the Company has an equity investment, but is not the primary beneficiary. Intercompany transactions have been eliminated in consolidation.

The seven natural gas distribution utilities are subject to regulation by the regulatory agencies of each state in which they operate. As such, the Company's financial statements reflect the effects of rate regulation in accordance with GAAP and comply with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates.

Pursuant to the Merger, Southern Company has pushed down the application of the acquisition method of accounting to the financial statements of the Company such that the assets and liabilities are recorded at their respective fair values, and goodwill has been established for the excess of the purchase price over the fair value of net identifiable assets. Accordingly, the financial statements of the Company for periods before and after July 1, 2016 (acquisition date) reflect different bases of accounting, and the financial positions and results of operations of those periods are not comparable. Throughout the financial statements and notes to the financial statements, periods prior to July 1, 2016 are identified as "predecessor," while periods after the acquisition date are identified as "successor."

Certain predecessor period data presented in the financial statements has been modified or reclassified to conform to the presentation used by the Company's new parent company, Southern Company. Changes to the statements of income include classifying operating revenues as natural gas revenues and other revenues as well as classifying cost of goods sold as cost of natural gas and cost of other sales, and presenting interest expense and AFUDC on a gross basis. Changes to the statements of cash flows include revised financial statement line item descriptions to align with the new balance sheet descriptions and expanded line items within each category of cash flow activity. Changes to the balance sheets include changing certain captions to conform to the presentation of Southern Company.

### Recently Issued Accounting Standards

#### *Revenue*

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers* (ASC 606), replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the new standard is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

Most of the Company's revenue, including energy provided to customers, is from tariff offerings that provide natural gas without a defined contractual term, as well as longer-term contractual agreements, including non-derivative natural gas asset management and optimization arrangements.

The Company has completed the evaluation of all revenue streams and determined that the adoption of ASC 606 will not change the current timing of revenue recognition for such transactions. Some revenue arrangements, such as energy-related derivatives and alternative revenue programs, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed or presented separately from revenues under ASC 606 on the Company's financial statements. The Company has concluded contributions in aid of construction are not in scope for ASC 606 and will continue to be accounted for as an offset to property, plant, and equipment.

The new standard is effective for reporting periods beginning after December 15, 2017. The Company applied the modified retrospective method of adoption effective January 1, 2018. The Company also utilized practical expedients which allowed it to apply the standard to open contracts at the date of adoption and to reflect the aggregate effect of all modifications when identifying performance obligations and allocating the transaction price for contracts modified before the effective date. Under the modified retrospective method of adoption, prior year reported results are not restated; however, a cumulative-effect adjustment to retained earnings at January 1, 2018 is recorded. In addition, quarterly disclosures will include comparative information on 2018 financial statement line items under current guidance. The adoption of ASC 606 did not result in a cumulative-effect adjustment .

***Leases***

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged . ASU 2016-02 is effective for fiscal years beginning after December 15, 2018 and the Company will adopt the new standard effective January 1, 2019.

The Company is currently implementing an information technology system along with the related changes to internal controls and accounting policies that will support the accounting for leases under ASU 2016-02. In addition, the Company has substantially completed a detailed inventory and analysis of its leases. In terms of rental charges and duration of contracts, the most significant leases relate to real estate and fleet vehicles where the Company is the lessee and to natural gas home appliances where the Company is the lessor. While the Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

***Other***

In March 2016, the FASB issued ASU No. 2016-09, *Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Note 5 for the disclosure impacted by ASU 2016-09.

In November 2016, the FASB issued ASU No. 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash* (ASU 2016-18). ASU 2016-18 eliminates the need to reflect transfers between cash and restricted cash in operating, investing, and financing activities in the statement of cash flows. Upon adoption, the net change in cash and cash equivalents during the period will include amounts generally described as restricted cash or restricted cash equivalents. ASU 2016-18 is effective for fiscal years beginning after December 15, 2017, and will be applied retrospectively to each period presented. The Company adopted ASU 2016-18 effective January 1, 2018 with no material impact on its financial statements.

On January 26, 2017, the FASB issued ASU No. 2017-04, *Intangibles – Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment* (ASU 2017-04). ASU 2017-04 removes the requirement to compare the implied fair value of goodwill with the carrying amount as part of Step 2 of the goodwill impairment test. Under the new standard, the goodwill impairment loss will be measured as the excess of a reporting unit's carrying amount over its fair value, not exceeding the total amount of goodwill allocated to that reporting unit, which may increase the frequency of goodwill impairment charges if a future goodwill impairment test does not pass the Step 1 evaluation. ASU 2017-04 is effective prospectively for periods beginning on or after December 15, 2019, with early adoption permitted. The Company adopted ASU 2017-04 effective January 1, 2018 with no impact on its financial statements.

On March 10, 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017-07). ASU 2017-07 requires that an employer report the service cost component in the same line item or items as other compensation costs and requires the other components of net periodic pension and postretirement benefit costs to be separately presented in the income statement outside of income from operations. Additionally, only the service cost component is eligible for capitalization, when applicable. However, all cost components remain eligible for capitalization under FERC regulations. ASU 2017-07 will be applied retrospectively for the presentation of the service cost component and the other components of net periodic pension and postretirement benefit costs in the income statement. The capitalization of only the service cost component of net periodic pension and postretirement benefit costs in assets will be applied on a prospective basis. ASU 2017-07 is effective for periods beginning after December 15, 2017. The presentation changes required for net periodic pension and postretirement benefit costs will result in a decrease in the Company's operating income and an increase in other income for 2016 and 2017 and are expected to result in a decrease in operating income and an increase in other income for 2018. The Company adopted ASU 2017-07 effective January 1, 2018 with no material impact on its financial statements.

On August 28, 2017, the FASB issued ASU No. 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities* (ASU 2017-12), amending the hedge accounting recognition and presentation requirements. ASU 2017-12 makes more financial and non-financial hedging strategies eligible for hedge accounting, amends the related presentation and disclosure requirements, and simplifies hedge effectiveness assessment requirements. ASU 2017-12 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

**Affiliate Transactions**

SCS, as agent for Alabama Power, Georgia Power, and Southern Power, and the Company have long-term interstate natural gas transportation agreements with SNG. The interstate transportation service provided to Alabama Power, Georgia Power, Southern Power, and the Company by SNG pursuant to these agreements is governed by the terms and conditions of SNG's natural gas tariff and is subject to FERC regulation. For the successor year ended December 31, 2017 , transportation revenue under these agreements from SCS and the Company were $136 million and $32 million , respectively. For the successor period of September 1, 2016 through December 31, 2016, transportation revenue under these agreements from SCS and the Company were $32 million and $15 million , respectively. See Note 4 under "Equity Method Investments – SNG" for additional information regarding the Company's investment in SNG.

The Company has an agreement with SCS under which the following services are currently being rendered to the Company as direct or allocated cost: accounting, finance and treasury, tax, information technology, auditing, insurance and pension administration, human resources, systems and procedures, purchasing, and other services. For the successor year ended December 31, 2017 and the successor period of July 1, 2016 through December 31, 2016 , costs for these services amounted to $63 million and $17 million , respectively. Cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

SCS, as agent for Alabama Power, Georgia Power, and Southern Power, has agreements with certain subsidiaries of the Company to purchase natural gas. For the successor year ended December 31, 2017 , natural gas purchases made by SCS from the Company's subsidiaries were $142 million . For the successor period of July 1, 2016 through December 31, 2016 , natural gas purchases made by SCS from the Company's subsidiaries were $27 million .

**Regulatory Assets and Liabilities**

The Company is subject to accounting requirements for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

| | 2017 | 2016 | Note |
|---|---|---|---|
| | *(in millions)* | | |
| Environmental remediation | $ **410** | $ 411 | (a,b) |
| Retiree benefit plans | **270** | 325 | (a,c) |
| Long-term debt fair value adjustment | **138** | 154 | (d) |
| Under recovered regulatory clause revenues | **98** | 118 | (e) |
| Other regulatory assets | **79** | 58 | (f) |
| Other cost of removal obligations | **(1,646)** | (1,616) | (g) |
| Deferred income tax credits | **(1,063)** | (22) | (g,i) |
| Over recovered regulatory clause revenues | **(144)** | (104) | (e) |
| Other regulatory liabilities | **(21)** | (39) | (h) |
| Total regulatory assets (liabilities), net | $ **(1,879)** | $ (715) | |

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Not earning a return as offset in rate base by a corresponding asset or liability.

(b) Recovered through environmental cost recovery mechanisms when the remediation is performed or the work is performed.

(c) Recovered and amortized over the average remaining service period which range up to 15 years . See Note 2 for additional information.

(d) Recovered over the remaining life of the original debt issuances, which range up to 21 years .

(e) Recorded and recovered or amortized as approved or accepted by the appropriate state regulatory agencies over periods generally not exceeding eight years .

(f) Comprised of several components including unamortized loss on reacquired debt, weather normalization, franchise gas, deferred depreciation expense, and financial instrument-hedging assets, which are recovered or amortized as approved by the applicable state regulatory agencies over periods generally not exceeding 10 years , except for financial hedging-instruments. Financial instrument-hedging assets are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed two years . Upon final settlement, actual costs incurred are recovered, and actual income earned is refunded through the energy cost recovery clause.

(g) Other cost of removal obligations are recorded and deferred income tax liabilities are amortized over the related property lives, which may range up to 80 years . Cost of removal liabilities will be settled and trued up following completion of the related activities.

(h) Comprised of several components including energy efficiency programs, unamortized bond issuance costs and financial instrument-hedging liabilities which are recovered or amortized as approved by the applicable state regulatory agencies over periods generally not exceeding a range of four years to 20 years , except for financial hedging-instruments. Financial instrument-hedging liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed two years . Upon final settlement, actual costs incurred are recovered, and actual income earned is refunded through the energy cost recovery clause.

(i) Includes excess deferred income tax liabilities not subject to normalization as a result of the Tax Reform Legislation, the recovery and amortization of which will be determined by the applicable state regulatory agencies. See Note 3 under "Regulatory Matters" and Note 5 for additional details.

In the event that a portion of a natural gas distribution utility's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the natural gas distribution utility would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Regulatory Matters" for additional information.

**Revenues**

***Gas Distribution Operations***

The Company records revenues when goods or services are provided to customers. Those revenues are based on rates approved by the state regulatory agencies of the Company's utilities. As required by the Georgia PSC, Atlanta Gas Light bills Marketers in equal monthly installments for each residential, commercial, and industrial end-use customer's distribution costs as well as for capacity costs utilizing a seasonal rate design for the calculation of each residential end-use customer's annual straight-fixed-variable charge, which reflects the historic volumetric usage pattern for the entire residential class.

All of the natural gas distribution utilities, with the exception of Atlanta Gas Light, have rate structures that include volumetric rate designs that allow the opportunity to recover certain costs based on gas usage. Revenues from sales and transportation services are recognized in the same period in which the related volumes are delivered to customers. Revenues from residential and certain commercial and industrial customers are recognized on the basis of scheduled meter readings. Additionally, unbilled revenues are recognized for estimated deliveries of gas not yet billed to these customers, from the last bill date to the end of the accounting period. For other commercial and industrial customers and for all wholesale customers, revenues are based on actual deliveries to the end of the period.

The tariffs for several of the natural gas distribution utilities include provisions which allow for the recognition of certain revenues prior to the time such revenues are billed to customers. These provisions are referred to as alternative revenue programs and provide for the recognition of certain revenues prior to billing, so long as the amounts recognized will be collected from customers within 24 months of recognition. These programs are as follows:

- *Weather normalization adjustments* – reduce customer bills when winter weather is colder than normal and increase customer bills when weather is warmer than normal and are included in the tariffs for Virginia Natural Gas, Elizabethtown Gas, and Chattanooga Gas;
- *Revenue normalization mechanisms* – mitigate the impact of conservation and declining customer usage and are contained in the tariffs for Virginia Natural Gas, Chattanooga Gas, and Elkton Gas; and
- *Revenue true-up adjustment* – included within the provisions of the Georgia Rate Adjustment Mechanism (GRAM) program in which Atlanta Gas Light participates as a short-term alternative to formal rate case filings, the revenue true-up feature provides for a monthly positive (or negative) adjustment to record revenue in the amount of any variance to budgeted revenues, which are submitted and approved annually as a requirement of GRAM. Such adjustments are reflected in customer billings in a subsequent program year.

*Revenue Taxes*

The Company charges customers for gas revenue and gas use taxes imposed on the Company and remits amounts owed to various governmental authorities. Gas revenue taxes are recorded at the amount charged to customers, which may include a small administrative fee, as operating revenues, and the related taxes imposed on the Company are recorded as operating expenses on the statements of income. Gas use taxes are excluded from revenue and expense with the related administrative fee included in operating revenues when the tax is imposed on the customer. Revenue taxes included in operating expenses were $98 million and $31 million for the successor year ended December 31, 2017 and the successor period of July 1, 2016 through December 31, 2016 , respectively, and $56 million and $101 million for the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 , respectively.

***Gas Marketing Services***

The Company recognizes revenues from natural gas sales and transportation services in the same period in which the related volumes are delivered to customers and recognizes sales revenues from residential and certain commercial and industrial customers on the basis of scheduled meter readings. The Company also recognizes unbilled revenues for estimated deliveries of gas not yet billed to these customers from the most recent meter reading date to the end of the accounting period. For other commercial and industrial customers and for all wholesale customers, revenues are based on actual deliveries during the period.

The Company recognizes revenues on 12-month utility-bill management contracts as the lesser of cumulative earned or cumulative billed amounts. Revenues for warranty and repair contracts are recognized on a straight-line basis over the contract term while revenues for maintenance services are recognized at the time such services are performed.

***Wholesale Gas Services***

The Company nets revenues from energy and risk management activities with the associated costs. Profits from sales between segments are eliminated and are recognized as goods or services sold to end-use customers. The Company records transactions that qualify as derivatives at fair value with changes in fair value recognized in earnings in the period of change and characterized as unrealized gains or losses. Gains and losses on derivatives held for energy trading purposes are presented on a net basis in revenue.

***Concentration of Revenue***

The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

**Cost of Natural Gas and Other Sales**

***Gas Distribution Operations***

Excluding Atlanta Gas Light, which does not sell natural gas to end-use customers, the Company charges its utility customers for natural gas consumed using natural gas cost recovery mechanisms set by the applicable state regulatory agencies. Under these mechanisms, all prudently-incurred natural gas costs are passed through to customers without markup, subject to regulatory review. The Company defers or accrues the difference between the actual cost of natural gas and the amount of commodity revenue earned in a given period such that no operating income is recognized related to these costs. The deferred or accrued amount is either billed or refunded to customers prospectively through adjustments to the commodity rate. Deferred and accrued natural gas costs are included in the balance sheets as regulatory assets and regulatory liabilities, respectively.

***Gas Marketing Services***

The Company's gas marketing services' customers are charged for actual or estimated natural gas consumed. Within cost of natural gas, the Company also includes costs of fuel and lost and unaccounted for gas, adjustments to reduce the value of inventories to market value, and gains and losses associated with certain derivatives. The Company records the costs to service its warranty and repair contract claims as cost of other sales.

**Income and Other Taxes**

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Federal ITCs utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented on the balance sheet, excluding revenue taxes which are presented on the statements of income. See "Revenues – Gas Distribution Operations – Revenue Taxes" herein for additional information.

The Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

**Property, Plant, and Equipment**

Property, plant, and equipment is stated at original cost, or fair value at the effective date of the Merger as appropriate, less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and cost of equity funds used during construction.

The Company's property, plant, and equipment in service consisted of the following at December 31:

| | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| Utility plant in service | **$ 13,079** | $ 11,996 |
| Information technology equipment and software | **366** | 324 |
| Storage facilities | **1,599** | 1,463 |
| Other | **789** | 725 |
| Total other plant in service | **2,754** | 2,512 |
| Total plant in service | **$ 15,833** | $ 14,508 |

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred or performed. The portion of non-working gas used to maintain the structural integrity of the Company's natural gas storage facilities that is considered to be non-recoverable is recorded as depreciable property, plant, and equipment, while the recoverable or retained portion is recorded as non-depreciable property, plant, and equipment.

The amount of non-cash property additions recognized for the successor periods of the year ended December 31, 2017 and July 1, 2016 through December 31, 2016 and the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 were $135 million , $63 million , $41 million , and $48 million , respectively. These amounts are comprised of construction-related accounts payable outstanding at the end of each period.

**Depreciation and Amortization**

Depreciation of the original cost of utility plant in service is provided using composite straight-line rates, which approximated 2.9% in 2017 , 2.8% in 2016 , and 2.7% in 2015 . Depreciation studies are conducted periodically to update the composite rates that are approved by the respective state regulatory agency. When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the asset are retired when the related property unit is retired.

Depreciation of the original cost of other plant in service is provided primarily on a straight-line basis over the following useful lives: five to 15 years for transportation equipment, 40 to 60 years for storage facilities, and up to 65 years for other assets.

**Allowance for Funds Used During Construction**

The Company records AFUDC for Atlanta Gas Light, Nicor Gas, Chattanooga Gas, and Elizabethtown Gas, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently, AFUDC increases the revenue requirement and is recovered over the service life of the asset through a higher rate base and higher depreciation. All current construction costs are included in rates. The capital expenditures of the other three natural gas utilities do not qualify for AFUDC treatment.

The Company's AFUDC composite rates are as follows:

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | **Year ended December 31, 2017** | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | Year ended December 31, 2015 |
| Atlanta Gas Light | **8.10%** | 4.05% | 4.05% | 8.10% |
| Chattanooga Gas | **7.41** | 3.71 | 3.71 | 7.41 |
| Elizabethtown Gas (*) | **1.56** | 0.84 | 0.84 | 1.69 |
| Nicor Gas (*) | **1.22** | 1.50 | 1.50 | 0.82 |

(*) Variable rate is determined by the FERC method of AFUDC accounting.

Cash payments for interest during the successor periods of the year ended December 31, 2017 and July 1, 2016 through December 31, 2016 and the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 totaled $223 million , $135 million , $119 million , and $181 million , respectively.

**Impairment of Long-Lived Assets**

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change. See Note 3 under "Other Matters" for additional information.

**Goodwill and Other Intangible Assets and Liabilities**

Goodwill is not amortized, but is subject to an annual impairment test during the fourth quarter of each year, or more frequently if impairment indicators arise. In assessing goodwill for impairment, the Company has the option of first performing a qualitative assessment to determine that it is more likely than not that fair value of its reporting unit exceeds its carrying value (commonly referred to as Step 0). If the Company chooses not to perform a qualitative assessment, or the result of Step 0 indicates a probable decrease in fair value of its reporting unit below its carrying value, a quantitative two-step test is performed (commonly referred to as Step 1 and Step 2). Step 1 compares the fair value of the reporting unit to its carrying value including goodwill. If the carrying value exceeds the fair value, Step 2 is performed to allocate the fair value of the reporting unit to its assets and liabilities in order to determine the implied fair value of goodwill, which is compared to the carrying value of goodwill to calculate an impairment loss, if any.

For the 2017 annual impairment test, the Company performed Step 1 of the two-step impairment test, which resulted in the fair value of all its reporting units that have goodwill exceeding their carrying value. For the 2016 and 2015 annual impairment tests, the Company performed the qualitative Step 0 assessment and determined that it was more likely than not that the fair value of all its reporting units with goodwill exceeded their carrying values, and therefore no quantitative assessment was required. In the third quarter 2015, the Company identified potential impairment indicators and performed an interim impairment test for its storage and fuels reporting unit, which resulted in impairment of the full $14 million goodwill balance for that reporting unit.

Goodwill and other intangible assets consisted of the following:

| | | At December 31, 2017 | | |
|---|---|---|---|---|
| | Estimated Useful Life | Gross Carrying Amount | Accumulated Amortization | Other Intangible Assets, Net |
| | | | *(in millions)* | |
| **Other intangible assets subject to amortization:** | | | | |
| ***Gas marketing services*** | | | | |
| Customer relationships | 11-16 years | $ 221 | $ (77) | $ 144 |
| Trade names | 10-28 years | 115 | (9) | 106 |
| ***Wholesale gas services*** | | | | |
| Storage and transportation contracts | 1-5 years | 64 | (34) | 30 |
| Total intangible assets subject to amortization | | $ 400 | $ (120) | $ 280 |
| | | | | |
| **Goodwill:** | | | | |
| ***Gas distribution operations*** | | $ 4,702 | $ — | $ 4,702 |
| ***Gas marketing services*** | | 1,265 | — | 1,265 |
| Total goodwill | | $ 5,967 | $ — | $ 5,967 |

| | | At December 31, 2016 | | |
|---|---|---|---|---|
| | Estimated Useful Life | Gross Carrying Amount | Accumulated Amortization | Other Intangible Assets, Net |
| | | | *(in millions)* | |
| **Other intangible assets subject to amortization:** | | | | |
| ***Gas marketing services*** | | | | |
| Customer relationships | 11-16 years | $ 221 | $ (30) | $ 191 |
| Trade names | 10-28 years | 115 | (2) | 113 |
| ***Wholesale gas services*** | | | | |
| Storage and transportation contracts | 1-5 years | 64 | (2) | 62 |
| Total intangible assets subject to amortization | | $ 400 | $ (34) | $ 366 |
| | | | | |
| **Goodwill:** | | | | |
| ***Gas distribution operations*** | | $ 4,702 | $ — | $ 4,702 |
| ***Gas marketing services*** | | 1,265 | — | 1,265 |
| Total goodwill | | $ 5,967 | $ — | $ 5,967 |

Amortization associated with intangible assets for gas marketing services, included in depreciation and amortization, for the successor year ended December 31, 2017 and the successor period of July 1, 2016 through December 31, 2016 and the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 was $54 million , $32 million , $8 million , and $18 million , respectively. Amortization of $32 million and $2 million for wholesale gas services was recorded as a reduction to operating revenues for the successor year ended December 31, 2017 and the successor period of July 1, 2016 through December 31, 2016 , respectively.

As of December 31, 2017 , the estimated amortization associated with other intangible assets is as follows:

| | Amortization |
|---|---|
| | *(in millions)* |
| 2018 | $ 58 |
| 2019 | 40 |
| 2020 | 28 |
| 2021 | 21 |
| 2022 | 17 |

Included in other deferred credits and liabilities on the balance sheets is $91 million of intangible liabilities that were recorded during acquisition accounting for transportation contracts at wholesale gas services. At December 31, 2017 , the accumulated amortization of these intangible liabilities was $50 million . The estimated amortization associated with the intangible liabilities that will be recorded in natural gas revenues is as follows:

| | Amortization |
|---|---|
| | *(in millions)* |
| 2018 | $ 24 |
| 2019 | 17 |

**Cash and Cash Equivalents**

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

**Energy Marketing Receivables and Payables**

Wholesale gas services provides services to retail gas marketers, wholesale gas marketers, utility companies, and industrial customers. These counterparties utilize netting agreements that enable wholesale gas services to net receivables and payables by counterparty upon settlement. Wholesale gas services also nets across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions. While the amounts due from, or owed to, wholesale gas services' counterparties are settled net, they are recorded on a gross basis in the balance sheets as energy marketing receivables and energy marketing payables.

Wholesale gas services has trade and credit contracts that contain minimum credit rating requirements. These credit rating requirements typically give counterparties the right to suspend or terminate credit if the Company's credit ratings are downgraded to non-investment grade status. Under such circumstances, wholesale gas services would need to post collateral to continue transacting business with some of its counterparties. As of December 31, 2017 and 2016 , the required collateral in the event of a credit rating downgrade was $8 million and immaterial, respectively.

Wholesale gas services has a concentration of credit risk for services it provides to its counterparties. This credit risk is generally concentrated in 20 of its counterparties and is measured by 30-day receivable exposure plus forward exposure. Counterparty credit risk is evaluated using an S&P equivalent credit rating, which is determined by a process of converting the lower of the S&P or Moody's rating to an internal rating ranging from 9 to 1 , with 9 being equivalent to AAA/Aaa by S&P and Moody's, respectively, and 1 being equivalent to D/Default by S&P and Moody's, respectively. A counterparty that does not have an external rating is assigned an internal rating based on the strength of its financial ratios. As of December 31, 2017 , the top 20 counterparties represented 48% , or $203 million , of the total counterparty exposure and had a weighted average S&P equivalent rating of A-.

Credit policies were established to determine and monitor the creditworthiness of counterparties, including requirements to post collateral or other credit security, as well as the quality of pledged collateral. Collateral or credit security is most often in the form of cash or letters of credit from an investment-grade financial institution, but may also include cash or U.S. government securities held by a trustee. When wholesale gas services is engaged in more than one outstanding derivative transaction with the same counterparty and it also has a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty combined with a reasonable measure of the Company's credit risk. Wholesale gas services also uses other netting agreements with certain counterparties with whom it conducts significant transactions.

**Receivables and Provision for Uncollectible Accounts**

The Company's other trade receivables consist primarily of natural gas sales and transportation services billed to residential, commercial, industrial, and other customers. Customers are billed monthly and payment is due within 30 days. For the majority of receivables, a provision for uncollectible accounts is established based on historical collection experience and other factors. For the remaining receivables, if the Company is aware of a specific customer's inability to pay, a provision for uncollectible accounts is recorded to reduce the receivable balance to the amount the Company reasonably expects to collect. If circumstances change, the estimate of the recoverability of accounts receivable could change as well. Circumstances that could affect this estimate include, but are not limited to, customer credit issues, customer deposits, and general economic conditions. Customers' accounts are written off once they are deemed to be uncollectible.

***Nicor Gas***

Credit risk exposure at Nicor Gas is mitigated by a bad debt rider approved by the Illinois Commission. The bad debt rider provides for the recovery from (or refund to) customers of the difference between Nicor Gas' actual bad debt experience on an annual basis and the benchmark bad debt expense used to establish its base rates for the respective year.

***Atlanta Gas Light***

Concentration of credit risk occurs at Atlanta Gas Light for amounts billed for services and other costs to its customers, which consist of 15 Marketers in Georgia. The credit risk exposure to Marketers varies seasonally, with the lowest exposure in the non-peak summer months and the highest exposure in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. The functions of the retail sale of gas include the purchase and sale of natural gas, customer service, billings, and collections. The provisions of Atlanta Gas Light's tariff allow Atlanta Gas Light to obtain credit security support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill from Atlanta Gas Light.

**Materials and Supplies**

Generally, materials and supplies include propane gas inventory, fleet fuel, and other materials and supplies. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

**Natural Gas for Sale**

The natural gas distribution utilities, with the exception of Nicor Gas, record natural gas inventories on a WACOG basis. In Georgia's competitive environment, Marketers sell natural gas to firm end-use customers at market-based prices. Part of the unbundling process, which resulted from deregulation and provides this competitive environment, is the assignment to Marketers of certain pipeline services that Atlanta Gas Light has under contract. On a monthly basis, Atlanta Gas Light assigns to Marketers the majority of the pipeline storage services that it has under contract, along with a corresponding amount of inventory. Atlanta Gas Light retains and manages a portion of its pipeline storage assets and related natural gas inventories for system balancing and to serve system demand.

Nicor Gas' inventory is carried at cost on a LIFO basis. Inventory decrements occurring during the year that are restored prior to year end are charged to cost of natural gas at the estimated annual replacement cost. Inventory decrements that are not restored prior to year end are charged to cost of natural gas at the actual LIFO cost of the inventory layers liquidated. The cost of gas, including inventory costs, is recovered from customers under a purchased gas recovery mechanism adjusted for differences between actual costs and amounts billed; therefore, LIFO liquidations have no impact on the Company's net income. At December 31, 2017 , the Nicor Gas LIFO inventory balance was $148 million . Based on the average cost of gas purchased in December 2017 , the estimated replacement cost of Nicor Gas' inventory at December 31, 2017 was $264 million . During 2017 , Nicor Gas did not liquidate any LIFO-based inventory.

The gas marketing services, wholesale gas services, and all other segments record inventory at LOCOM, with cost determined on a WACOG basis. For these segments, the Company evaluates the weighted average cost of its natural gas inventories against market prices to determine whether any declines in market prices below the WACOG are other than temporary. For any declines considered to be other than temporary, the Company recorded the following LOCOM adjustments to cost of natural gas to reduce the value of its natural gas inventories to market value.

**NOTES (continued)**
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| | Successor | | Predecessor | |
|---|---|---|---|---|
| | **2017** | July 1, 2016 to December 31, 2016 | January 1, 2016 to June 30, 2016 | 2015 |
| | *(in millions)* | | *(in millions)* | |
| Gas marketing services | **$ —** | $ — | $ — | $ 3 |
| Wholesale gas services | **2** | 1 | 3 | 19 |
| All other | **—** | — | — | 1 |
| Total LOCOM adjustments | **$ 2** | $ 1 | $ 3 | $ 23 |

**Fair Value Measurements**

The Company has financial and nonfinancial assets and liabilities subject to fair value measurement. The financial assets and liabilities measured and carried at fair value include cash and cash equivalents and derivative instruments. The carrying values of receivables, short and long-term investments, accounts payable, short-term debt, other current assets and liabilities, and accrued interest approximate their respective fair value. The nonfinancial assets and liabilities include pension and other postretirement benefits. See Notes 2 and 9 for additional fair value disclosures.

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The Company utilizes market data or assumptions that market participants would use in valuing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. The Company primarily applies the market approach for recurring fair value measurements to utilize the best available information. Accordingly, the Company uses valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. Fair value balances are classified based on the observance of those inputs. The guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy defined by the guidance are as follows:

***Level 1***

Quoted prices in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. The Company's Level 1 items consist of exchange-traded derivatives, money market funds, and certain retirement plan assets.

***Level 2***

Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial and commodity instruments that are valued using valuation methodologies. These methodologies are primarily industry-standard methodologies that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace. Market price data is obtained from multiple sources in order to value certain Level 2 transactions and this data is representative of transactions that occurred in the marketplace. Level 2 instruments include shorter tenor exchange-traded and non-exchange-traded derivatives such as over-the-counter (OTC) forwards and options and certain retirement plan assets.

***Level 3***

Pricing inputs include significant unobservable inputs that may be used with internally developed methodologies to determine management's best estimate of fair value from the perspective of market participants. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs. Level 3 assets, liabilities, and any applicable transfers are primarily related to the Company's pension and other postretirement benefit plan assets as described in Note 2. Transfers into and out of Level 3 are determined using values at the end of the interim period in which the transfer occurred.

**Financial Instruments**

The Company uses derivative financial instruments to limit exposure to fluctuations in natural gas prices, weather, interest rates, and commodity prices. All derivative financial instruments are recognized as either assets or liabilities on the balance sheets (shown separately as "Risk Management Activities") and are measured at fair value. See Note 9 for additional information regarding fair value. Derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the respective state regulatory agency approved fuel-hedging programs result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Cash flows from derivatives are classified on the statement of cash flows in the same category as the hedged item. See Note 10 for additional information regarding derivatives.

The Company offsets fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. The Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2017 .

The Company enters into weather derivative contracts as economic hedges of natural gas revenues in the event of warmer-than-normal weather in the Heating Season. Exchange-traded options are carried at fair value, with changes reflected in natural gas revenues. Non-exchange-traded options are accounted for using the intrinsic value method. Changes in the intrinsic value for non-exchange-traded contracts are also reflected in natural gas revenues in the statements of income.

Wholesale gas services purchases natural gas for storage when the current market price paid to buy and transport natural gas plus the cost to store and finance the natural gas is less than the market price that can be received in the future, resulting in positive net natural gas revenues. NYMEX futures and OTC contracts are used to sell natural gas at that future price to substantially protect the natural gas revenues that will ultimately be realized when the stored natural gas is sold. The Company enters into transactions to secure transportation capacity between delivery points in order to serve its customers and various markets. NYMEX futures and OTC contracts are used to capture the price differential or spread between the locations served by the capacity in order to substantially protect the natural gas revenues that will ultimately be realized when the physical flow of natural gas between delivery points occurs. These contracts generally meet the definition of derivatives and are carried at fair value on the balance sheets, with changes in fair value recorded in natural gas revenues on the statements of income in the period of change. These contracts are not designated as hedges for accounting purposes.

The purchase, transportation, storage, and sale of natural gas are accounted for on a weighted average cost or accrual basis, as appropriate, rather than on the fair value basis utilized for the derivatives used to mitigate the natural gas price risk associated with the storage and transportation portfolio. Monthly demand charges are incurred for the contracted storage and transportation capacity and payments associated with asset management agreements, and these demand charges and payments are recognized on the statements of income in the period they are incurred. This difference in accounting methods can result in volatility in reported earnings, even though the economic margin is substantially unchanged from the dates the transactions were consummated.

The Company is exposed to potential losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

### Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, certain changes in pension and other postretirement benefit plans, and reclassifications for amounts included in net income.

### Non-Wholly Owned Entities

The Company holds ownership interests in a number of business ventures with varying ownership structures and evaluates all of its partnership interests and other variable interests to determine if each entity is a VIE. If a venture is a VIE for which the Company is the primary beneficiary, the assets, liabilities, and results of operations of the entity are consolidated. The Company reassesses its conclusion as to whether an entity is a VIE upon certain occurrences, which are deemed reconsideration events under the guidance. See Note 4 under "Variable Interest Entities" for additional information.

For entities that are not determined to be VIEs, the Company evaluates whether it has control or significant influence over the investee to determine the appropriate consolidation and presentation. Generally, entities under the control of the Company are consolidated, and entities over which the Company can exert significant influence, but does not control, are accounted for under the equity method of accounting. However, the Company also invests in partnerships and limited liability companies that maintain separate ownership accounts. All such investments are required to be accounted for under the equity method unless the interest is so minor that there is virtually no influence over operating and financial policies, as are all investments in joint ventures.

Investments accounted for under the equity method are recorded within equity investments in unconsolidated subsidiaries within the other property and investments section in the balance sheets and the equity income is recorded within earnings from equity method investments within the other income (expense) section in the statements of income. See Note 4 under "Equity Method Investments" for additional information.

## 2 . RETIREMENT BENEFITS

The Company has a qualified defined benefit, trusteed, pension plan covering most eligible employees, which was closed in 2012 to new employees and reopened to all non-union employees on January 1, 2018. The qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2017 and no mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2018 . The Company also provides certain non-qualified defined benefit and defined contribution pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for eligible retired employees through a postretirement benefit plan. The Company also has a separate unfunded supplemental retirement health care plan that provides medical care and life insurance benefits to employees of discontinued businesses. For the year ending December 31, 2018 , no other postretirement trust contributions are expected.

In connection with the Merger, the Company performed updated valuations of its pension and other postretirement benefit plan assets and obligations to reflect actual census data at the new measurement date of July 1, 2016. This valuation resulted in increases to the projected benefit obligations for the pension and other postretirement benefit plans of approximately $177 million and $20 million , respectively, a decrease in the fair value of pension plan assets of $10 million , and an increase in the fair value of other postretirement benefit plan assets of $1 million . The Company also recorded a related regulatory asset of $437 million related to unrecognized prior service cost and actuarial gain/loss, as it is probable that this amount will be recovered through future rates for the natural gas distribution utilities. The previously unrecognized prior service cost and actuarial gain/loss related to non-utility subsidiaries were eliminated through purchase accounting adjustments.

### Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the net periodic costs for the pension and other postretirement benefit plans for all periods presented and the benefit obligations as of the measurement date are presented below.

| | Successor | | Predecessor | |
|---|---|---|---|---|
| **Assumptions used to determine net periodic costs:** | **Year ended December 31, 2017** | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | Year ended December 31, 2015 |
| **Pension plans** | | | | |
| Discount rate – interest costs [(a)] | **3.76%** | 3.21% | 4.00% | 4.20% |
| Discount rate – service costs [(a)] | **4.64** | 4.07 | 4.80 | 4.20 |
| Expected long-term return on plan assets | **7.60** | 7.75 | 7.80 | 7.80 |
| Annual salary increase | **3.50** | 3.50 | 3.70 | 3.70 |
| Pension band increase [(b)] | **N/A** | 2.00 | 2.00 | 2.00 |
| **Other postretirement benefit plans** | | | | |
| Discount rate – interest costs [(a)] | **3.40%** | 2.84% | 3.60% | 4.00% |
| Discount rate – service costs [(a)] | **4.55** | 3.96 | 4.70 | 4.00 |
| Expected long-term return on plan assets | **6.03** | 5.93 | 6.60 | 7.80 |
| Annual salary increase | **3.50** | 3.50 | 3.70 | 3.70 |

(a) Effective January 1, 2016, the Company uses a spot rate approach to estimate the service cost and interest cost components. Previously, the Company estimated these components using a single weighted average discount rate.

(b) Only applicable to Nicor Gas union employees. The pension bands for the former Nicor plan reflect the negotiated rates in accordance with the union agreements.

| Assumptions used to determine benefit obligations: | 2017 | 2016 |
|---|---|---|
| **Pension plans** | | |
| Discount rate | **3.74%** | 4.39% |
| Annual salary increase | **2.88** | 3.50 |
| Pension band increase (*) | **N/A** | 2.00 |
| **Other postretirement benefit plans** | | |
| Discount rate | **3.62%** | 4.15% |
| Annual salary increase | **2.56** | 3.50 |

(*) Only applicable to Nicor Gas union employees. The pension bands for the former Nicor plan reflect the negotiated rates in accordance with the union agreements.

The Company estimates the expected return on pension plan and other postretirement benefit plan assets by evaluating expected bond returns, equity risk premiums, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing, and historical performance. The Company also considers guidance from its investment advisors in making a final determination of its expected rate of return on assets. To the extent the actual rate of return on assets realized over the course of a year is greater or less than the assumed rate, it does not affect that year's annual pension or other postretirement benefit plan cost; rather, this gain or loss reduces or increases future pension or other postretirement benefit plan costs.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2017 were as follows:

| | Initial Cost Trend Rate | Ultimate Cost Trend Rate | Year That Ultimate Rate is Reached |
|---|---|---|---|
| Pre-65 | 6.40% | 4.50% | 2038 |
| Post-65 medical | 7.80 | 4.50 | 2038 |
| Post-65 prescription | 7.80 | 4.50 | 2038 |

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2017 as follows:

| | 1 Percent Increase | 1 Percent Decrease |
|---|---|---|
| | *(in millions)* | |
| Benefit obligation | $ 11 | $ (10) |
| Service and interest costs | — | — |

**Pension Plans**

The total accumulated benefit obligation for the pension plans was $1.1 billion at December 31, 2017 and $1.1 billion at December 31, 2016 . Changes in the projected benefit obligations and the fair value of plan assets for all periods presented were as follows:

| | Successor | | Predecessor |
|---|---|---|---|
| | **Year ended December 31, 2017** | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 |
| | *(in millions)* | | *(in millions)* |
| **Change in benefit obligation** | | | |
| Benefit obligation at beginning of period | **$ 1,133** | $ 1,244 ` | $ 1,067 |
| Service cost | **23** | 15 | 13 |
| Interest cost | **42** | 20 | 21 |
| Plan amendments | **(26)** | — | — |
| Benefits paid | **(91)** | (31) | (26) |
| Actuarial (gain) loss | **103** | (115) | 169 |
| Balance at end of period | **1,184** | 1,133 | 1,244 |
| **Change in plan assets** | | | |
| Fair value of plan assets at beginning of period | **983** | 837 ` | 847 |
| Actual return (loss) on plan assets | **175** | 48 | 15 |
| Employer contributions | **1** | 129 | 1 |
| Benefits paid | **(91)** | (31) | (26) |
| Fair value of plan assets at end of period | **1,068** | 983 | 837 |
| Accrued liability | **$ 116** | $ 150 | $ 407 |

At December 31, 2017 , the projected benefit obligations for the qualified and non-qualified pension plans were $1.1 billion and $44 million , respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2017 and 2016 related to the Company's pension plans consist of the following:

| | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| Other regulatory assets, deferred | **$ 217** | $ 267 |
| Other deferred charges and assets | **85** | 58 |
| Other current liabilities | **(3)** | (2) |
| Employee benefit obligations | **(198)** | (206) |

Presented below are the amounts included in accumulated OCI and regulatory assets at December 31, 2017 and 2016 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2018 .

| | Regulatory Amortization | Prior Service Cost | Net (Gain) Loss |
|---|---|---|---|
| | | *(in millions)* | |
| **Balance at December 31, 2017:** | | | |
| Accumulated OCI | **$ —** | **$ —** | **$ (42)** |
| Regulatory assets (liabilities) | **40** | **(20)** | **197** |
| Total | **$ 40** | **$ (20)** | **$ 155** |
| **Balance at December 31, 2016:** | | | |
| Accumulated OCI | $ — | $ — | $ (43) |
| Regulatory assets (liabilities) | — | (2) | 269 |
| Total | $ — | $ (2) | $ 226 |
| **Estimated amortization in net periodic cost in 2018:** | | | |
| Regulatory assets (liabilities) | **$ 3** | **$ (2)** | **$ 16** |

The components of OCI and the changes in the balance of regulatory assets related to the defined benefit pension plans for all periods presented were as follows:

| | Accumulated OCI | Regulatory Assets |
|---|---|---|
| | *(in millions)* | |
| **Predecessor – Balance at December 31, 2015:** | $ 282 | $ 88 |
| Reclassification adjustments: | | |
| Amortization of prior service costs | 1 | — |
| Amortization of net loss | (9) | (4) |
| Total reclassification adjustments | (8) | (4) |
| Total change | (8) | (4) |
| **Predecessor – Balance at June 30, 2016:** | $ 274 | $ 84 |
| **Successor – Balance at July 1, 2016:** | $ — | $ 368 |
| Net (gain) loss | (43) | (87) |
| Reclassification adjustments: | | |
| Amortization of prior service costs | — | 1 |
| Amortization of net loss | — | (15) |
| Total reclassification adjustments | — | (14) |
| Total change | (43) | (101) |
| **Successor – Balance at December 31, 2016:** | $ (43) | $ 267 |
| Net (gain) loss | **1** | **(31)** |
| Reclassification adjustments: | | |
| Amortization of regulatory assets | **—** | **(1)** |
| Amortization of net loss | **—** | **(18)** |
| Total reclassification adjustments | **—** | **(19)** |
| Total change | **1** | **(50)** |
| **Successor – Balance at December 31, 2017:** | **$ (42)** | **$ 217** |

**NOTES (continued)**
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Components of net periodic pension costs for all periods presented were as follows:

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | **Year ended December 31, 2017** | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | Year ended December 31, 2015 |
| | *(in millions)* | | *(in millions)* | |
| Service cost | **$ 23** | $ 15 | $ 13 | $ 28 |
| Interest cost | **42** | 20 | 21 | 45 |
| Expected return on plan assets | **(70)** | (35) | (33) | (65) |
| Amortization of regulatory assets | **1** | — | — | — |
| Amortization: | | | | |
| Prior service costs | **—** | (1) | (1) | (2) |
| Net (gain)/loss | **18** | 14 | 13 | 31 |
| Net periodic pension cost | **$ 14** | $ 13 | $ 13 | $ 37 |

Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2017 , estimated benefit payments were as follows:

| | **Benefit Payments** |
|---|---|
| | *(in millions)* |
| 2018 | $ 100 |
| 2019 | 77 |
| 2020 | 79 |
| 2021 | 79 |
| 2022 | 80 |
| 2023 to 2027 | 392 |

**Other Postretirement Benefits**

Changes in the APBO and the fair value of plan assets for all periods presented were as follows:

| | Successor | | Predecessor |
|---|---|---|---|
| | **Year ended December 31, 2017** | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 |
| | *(in millions)* | | *(in millions)* |
| **Change in benefit obligation** | | | |
| Benefit obligation at beginning of period | **$ 308** | $ 338 | $ 318 |
| Service cost | **2** | 1 | 1 |
| Interest cost | **10** | 5 | 5 |
| Benefits paid | **(19)** | (11) | (11) |
| Actuarial (gain) loss | **3** | (26) | 24 |
| Plan amendments | **3** | — | — |
| Employee contributions | **3** | 1 | 1 |
| Balance at end of period | **310** | 308 | 338 |
| **Change in plan assets** | | | |
| Fair value of plan assets at beginning of period | **105** | 100 | 99 |
| Actual return (loss) on plan assets | **20** | 4 | 1 |
| Employee contributions | **3** | 1 | 1 |
| Employer contributions | **17** | 11 | 10 |
| Benefits paid | **(20)** | (11) | (11) |
| Fair value of plan assets at end of year | **125** | 105 | 100 |
| Accrued liability | **$ 185** | $ 203 | $ 238 |

Amounts recognized in the balance sheets at December 31, 2017 and 2016 related to the Company's other postretirement benefit plans consist of the following:

| | **2017** | 2016 |
|---|---|---|
| | *(in millions)* | |
| Other regulatory assets, deferred | **$ 46** | $ 52 |
| Employee benefit obligations | **(185)** | (203) |

Presented below are the amounts included in accumulated OCI and regulatory assets at December 31, 2017 and 2016 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost. The estimated amortization of such amounts for 2018 is immaterial.

| | **Regulatory Amortization** | **Prior Service Cost** | **Net (Gain) Loss** |
|---|---|---|---|
| | | *(in millions)* | |
| **Balance at December 31, 2017:** | | | |
| Accumulated OCI | **$ —** | **$ —** | **$ (3)** |
| Regulatory assets (liabilities) | **6** | **(7)** | **47** |
| Total | **$ 6** | **$ (7)** | **$ 44** |
| **Balance at December 31, 2016:** | | | |
| Accumulated OCI | $ — | $ — | $ (3) |
| Regulatory assets (liabilities) | — | (12) | 64 |
| Total | $ — | $ (12) | $ 61 |

The components of OCI, along with the changes in the balance of regulatory assets (liabilities), related to the other postretirement benefit plans for all periods presented were as follows:

| | Accumulated OCI | Regulatory Assets |
|---|---|---|
| | *(in millions)* | |
| **Predecessor – Balance at December 31, 2015:** | $ 36 | $ 30 |
| Net (gain) loss | — | — |
| Reclassification adjustments: | | |
| Amortization of prior service costs | — | 1 |
| Amortization of net loss | (1) | (1) |
| Total reclassification adjustments | (1) | — |
| Total change | (1) | — |
| **Predecessor – Balance at June 30, 2016:** | $ 35 | $ 30 |
| | | |
| **Successor – Balance at July 1, 2016:** | $ — | $ 77 |
| Net (gain) loss | (3) | (23) |
| Reclassification adjustments: | | |
| Amortization of prior service costs | — | 1 |
| Amortization of net loss | — | (3) |
| Total reclassification adjustments | — | (2) |
| Total change | (3) | (25) |
| **Successor – Balance at December 31, 2016:** | $ (3) | $ 52 |
| Net (gain) loss | **—** | **(5)** |
| Reclassification adjustments: | | |
| Amortization of prior service costs | **—** | **3** |
| Amortization of net loss | **—** | **(4)** |
| Total reclassification adjustments | **—** | **(1)** |
| Total change | **—** | **(6)** |
| **Successor – Balance at December 31, 2017:** | **$ (3)** | **$ 46** |

Components of the other postretirement benefit plans' net periodic cost for all periods presented were as follows:

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | **Year ended December 31, 2017** | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | Year ended December 31, 2015 |
| | *(in millions)* | | *(in millions)* | |
| Service cost | **$ 2** | $ 1 | $ 1 | $ 2 |
| Interest cost | **10** | 5 | 5 | 13 |
| Expected return on plan assets | **(7)** | (3) | (3) | (7) |
| Amortization of regulatory assets | **—** | 2 | — | — |
| Amortization: | | | | |
| Prior service costs | **(3)** | — | (1) | (3) |
| Net (gain)/loss | **4** | — | 2 | 6 |
| Net periodic postretirement benefit cost | **$ 6** | $ 5 | $ 4 | $ 11 |

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. At December 31, 2017 , estimated benefit payments were as follows:

| | Benefit Payments |
|---|---|
| | *(in millions)* |
| 2018 | $ 20 |
| 2019 | 20 |
| 2020 | 21 |
| 2021 | 21 |
| 2022 | 22 |
| 2023 to 2027 | 105 |

**Benefit Plan Assets**

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended. The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2017 and 2016 , along with the targets for each plan, is presented below:

| | Target | **2017** | 2016 |
|---|---|---|---|
| **Pension plan assets:** | | | |
| Equity | 53% | **65%** | 69% |
| Fixed Income | 15 | **19** | 20 |
| Cash | 2 | **6** | 1 |
| Other | 30 | **10** | 10 |
| Balance at end of period | 100% | **100%** | 100% |
| **Other postretirement benefit plan assets:** | | | |
| Equity | 72% | **76%** | 74% |
| Fixed Income | 24 | **20** | 23 |
| Cash | 1 | **2** | 1 |
| Other | 3 | **2** | 2 |
| Total | 100% | **100%** | 100% |

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns and interest rates, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program for its pension plan assets. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices. Management believes the portfolio is well-diversified with no significant concentrations of risk.

**NOTES (continued)**
**Southern Company Gas and Subsidiary Companies 2017 Annual Report**

***Investment Strategies***

Detailed below is a description of the investment strategies for the successor period for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

The investment strategies for the predecessor periods followed a policy to preserve the plans' capital and maximize investment earnings in excess of inflation within acceptable levels of capital market volatility. To accomplish this goal, the plans' assets were managed to optimize long-term return while maintaining a high standard of portfolio quality and diversification. In developing the allocation policy for the assets of the pension and other postretirement benefit plans, the Company examined projections of asset returns and volatility over a long-term horizon. In connection with this analysis, the risk and return trade-offs of alternative asset classes and asset mixes were evaluated given long-term historical relationships as well as prospective capital market returns. The Company also conducted asset-liability studies to match projected asset growth with projected liability growth to determine whether there is sufficient liquidity for projected benefit payments. Asset mix guidelines were developed by incorporating the results of these analyses with an assessment of the Company's risk posture, and taking into account industry practices. The Company periodically evaluated its investment strategy to ensure that plan assets were sufficient to meet the benefit obligations of the plans. As part of the ongoing evaluation, the Company made changes to its targeted asset allocations and investment strategy.

***Benefit Plan Asset Fair Values***

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2017 and 2016 . The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation for the successor period, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate. Management believes the portfolio is well-diversified with no significant concentrations of risk.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- ***Domestic and international equity.*** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- ***Fixed income.*** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- ***Real estate investments, private equity, and special situations investments.*** Investments in real estate, private equity, and special situations are generally classified as Net Asset Value as a Practical Expedient, since the underlying assets typically do not have publicly available observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. Techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, discounted cash flow analysis, prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals. The fair value of partnerships is determined by aggregating the value of the underlying assets less liabilities.

**NOTES (continued)**
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The fair values of pension plan assets as of December 31, 2017 and 2016 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. For 2017 and 2016 , special situations (absolute return and hedge funds) investment assets are presented in the table below based on the nature of the investment.

| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| **As of December 31, 2017:** | **Quoted Prices in Active Markets for Identical Assets (Level 1)** | **Significant Other Observable Inputs (Level 2)** | **Significant Unobservable Inputs (Level 3)** | **Net Asset Value as a Practical Expedient (NAV)** | **Total** |
| | | | *(in millions)* | | |
| Assets: | | | | | |
| Domestic equity (*) | $ 155 | $ 323 | $ — | $ — | $ 478 |
| International equity (*) | — | 166 | — | — | 166 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 85 | — | — | 85 |
| Corporate bonds | — | 39 | — | — | 39 |
| Cash equivalents and other | 84 | 25 | — | 48 | 157 |
| Real estate investments | 3 | — | — | 16 | 19 |
| Private equity | — | — | — | 1 | 1 |
| Total | $ 242 | $ 638 | $ — | $ 65 | $ 945 |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| **As of December 31, 2016:** | **Quoted Prices in Active Markets for Identical Assets (Level 1)** | **Significant Other Observable Inputs (Level 2)** | **Significant Unobservable Inputs (Level 3)** | **Net Asset Value as a Practical Expedient (NAV)** | **Total** |
| | | | *(in millions)* | | |
| Assets: | | | | | |
| Domestic equity (*) | $ 142 | $ 343 | $ — | $ — | $ 485 |
| International equity (*) | — | 185 | — | — | 185 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 85 | — | — | 85 |
| Corporate bonds | — | 41 | — | — | 41 |
| Pooled funds | — | 66 | — | — | 66 |
| Cash equivalents and other | 12 | 5 | — | 83 | 100 |
| Real estate investments | 4 | — | — | 15 | 19 |
| Private equity | — | — | — | 2 | 2 |
| Total | $ 158 | $ 725 | $ — | $ 100 | $ 983 |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

**NOTES (continued)**
**Southern Company Gas and Subsidiary Companies 2017 Annual Report**

The fair values of other postretirement benefit plan assets as of December 31, 2017 and 2016 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. For 2017 and 2016 , special situations (absolute return and hedge funds) investment assets are presented in the table below based on the nature of the investment.

| As of December 31, 2017: | Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Net Asset Value as a Practical Expedient (NAV) | Total |
|---|---|---|---|---|---|
| | | | *(in millions)* | | |
| Assets: | | | | | |
| Domestic equity (*) | $ 3 | $ 69 | $ — | $ — | $ 72 |
| International equity (*) | — | 22 | — | — | 22 |
| Fixed income: | | | | | |
| Pooled funds | — | 24 | — | — | 24 |
| Cash equivalents and other | 2 | — | — | 1 | 3 |
| Total | $ 5 | $ 115 | $ — | $ 1 | $ 121 |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

| As of December 31, 2016: | Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Net Asset Value as a Practical Expedient (NAV) | Total |
|---|---|---|---|---|---|
| | | | *(in millions)* | | |
| Assets: | | | | | |
| Domestic equity (*) | $ 3 | $ 58 | $ — | $ — | $ 61 |
| International equity (*) | — | 18 | — | — | 18 |
| Fixed income: | | | | | |
| Pooled funds | — | 23 | — | — | 23 |
| Cash equivalents and other | 1 | — | — | 2 | 3 |
| Total | $ 4 | $ 99 | $ — | $ 2 | $ 105 |

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

**Employee Savings Plan**

SCS sponsors 401(k) defined contribution plans covering certain eligible Southern Company Gas employees. Through December 31, 2017, the 401(k) plans provided matching contributions of either 65% on up to 8% of an employee's eligible compensation, or a 100% matching contribution on up to 3% of an employee's eligible compensation, followed by a 75% matching contribution on up to the next 3% of an employee's eligible compensation. Total matching contributions made to the 401(k) plans for the successor periods ended December 31, 2017 and 2016 were $17 million and $8 million , respectively, and for the predecessor periods ended June 30, 2016 and December 31, 2015 were $10 million and $16 million , respectively.

For employees not accruing a benefit under the pension plan, additional contributions made to the 401(k) plans for the successor period ended December 31, 2017 were $2 million , for the successor period ended December 31, 2016 were not material, and for the predecessor periods ended June 30, 2016 and December 31, 2015 were $2 million for each period.

Effective January 1, 2018, the 401(k) plans were merged into the Southern Company Employee Savings Plan, which is a defined contribution plan covering substantially all employees of the Company. Under this plan, the Company matches a portion of the first 6% of employee base salary contributions. The maximum Company match is 5.1% of an employee's base salary.

## 3 . CONTINGENCIES AND REGULATORY MATTERS

### General Litigation Matters

Nicor Gas and Nicor Energy Services Company, wholly-owned subsidiaries of the Company, and Nicor Inc. were defendants in a putative class action initially filed in 2011 in the state court in Cook County, Illinois. The plaintiffs purported to represent a class of the customers who purchased the Gas Line Comfort Guard product from Nicor Energy Services Company and variously alleged that the marketing, sale, and billing of the Gas Line Comfort Guard product violated the Illinois Consumer Fraud and Deceptive Business Practices Act, constituting common law fraud and resulting in unjust enrichment of these entities. The plaintiffs sought, on behalf of the classes they purported to represent, actual and punitive damages, interest, costs, attorney fees, and injunctive relief. On February 8, 2017, the judge denied the plaintiffs' motion for class certification and the Company's motion for summary judgment. On March 7, 2017, the parties reached a settlement, which was finalized and effective on April 3, 2017. The settlement did not have a material impact on the Company's financial statements.

The Company is assessing its alleged involvement in an incident that occurred in one of its service territories that resulted in several deaths, injuries, and property damage. One of the Company's utilities has been named as one of the defendants in several lawsuits related to this incident. The Company has insurance that provides full coverage of any financial exposure in excess of $11 million that is related to this incident. During the successor period ended December 31, 2016 and the predecessor period ended December 31, 2015 , the Company recorded reserves for substantially all of its potential exposure from these cases. The ultimate outcome of this matter cannot be determined at this time.

The Company is subject to certain claims and legal actions arising in the ordinary course of business. The ultimate outcome of these matters and such pending or potential litigation against the Company cannot be determined at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

### Environmental Matters

The Company's operations are regulated by state and federal environmental agencies through a variety of laws and regulations governing air, water, land, and protection of other natural resources. The Company maintains a comprehensive environmental compliance strategy to assess upcoming requirements and compliance costs associated with these environmental laws and regulations. The costs, including capital expenditures and operations and maintenance costs, required to comply with environmental laws and regulations impact future results of operations, cash flows, and financial condition. Compliance costs may result from the installation of additional environmental controls. Compliance with these environmental requirements involves significant capital and operating costs to clean up affected sites. The Company conducts studies to determine the extent of any required clean up and has recognized in its financial statements the costs to clean up known impacted sites. The natural gas distribution utilities in Illinois, New Jersey, Georgia, and Florida have each received authority from their applicable state regulatory agencies to recover approved environmental compliance costs through regulatory mechanisms.

The Company is subject to environmental remediation liabilities associated with 46 former MGP sites in five different states. Accrued environmental remediation costs of $388 million and $426 million have been recorded in the balance sheets as of December 31, 2017 and 2016, respectively. These environmental remediation expenditures are recoverable from customers through rate mechanisms approved by the applicable state regulatory agencies, with the exception of one site representing $2 million of the accrued remediation costs.

In 2015, the EPA filed an administrative complaint and notice of opportunity for hearing against Nicor Gas. The complaint alleged violation of the regulatory requirements applicable to polychlorinated biphenyls in the Nicor Gas distribution system and the EPA sought a total civil penalty of $0.3 million . On January 26, 2017, the EPA notified Nicor Gas that it agreed to voluntarily dismiss its administrative complaint with prejudice and without payment of a civil penalty or other further obligation on the part of Nicor Gas.

The Company's ultimate environmental compliance strategy and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and the outcome of any legal challenges to the environmental rules. The ultimate outcome of these matters cannot be determined at this time.

### FERC Matters

At December 31, 2017 , gas midstream operations was involved in two gas pipeline construction projects. These projects, along with the Company's existing pipelines, are intended to provide diverse sources of natural gas supplies to customers, resolve current and long-term supply planning for new capacity, enhance system reliability, and generate economic development in the areas served. On October 13, 2017, the Atlantic Coast Pipeline project received FERC approval. On January 19, 2018, the PennEast Pipeline project received FERC approval.

Additionally, on August 1, 2017, the Dalton Pipeline was placed in service as authorized by the FERC and transportation service for customers commenced. See Note 4 for additional information.

**Regulatory Matters**

***Regulatory Infrastructure Programs***

The Company has infrastructure improvement programs at several of its utilities. Descriptions of these programs are as follows:

*Nicor Gas*

In 2013, Illinois enacted legislation that allows Nicor Gas to provide more widespread safety and reliability enhancements to its distribution system. The legislation stipulates that rate increases to customers as a result of any infrastructure investments shall not exceed a cumulative annual average of 4.0% or, in any given year, 5.5% , of base rate revenues. In 2014, the Illinois Commission approved the nine -year regulatory infrastructure program, Investing in Illinois, under which Nicor Gas implemented rates that became effective in March 2015.

Investing in Illinois is subject to annual review by the Illinois Commission. In conjunction with the base rate case order issued by the Illinois Commission on January 31, 2018, Nicor Gas is recovering the portion of these program costs incurred prior to December 31, 2017 through base rates. See "Base Rate Cases" herein for additional information.

*Atlanta Gas Light*

Atlanta Gas Light's STRIDE program, which was initially approved by the Georgia PSC in 2009, is comprised of the Integrated System Reinforcement Program (i-SRP), the Integrated Customer Growth Program (i-CGP), and the Integrated Vintage Plastic Replacement Program (i-VPR) and consists of infrastructure development, enhancement, and replacement programs that are used to update and expand distribution systems and LNG facilities, improve system reliability, and meet operational flexibility and growth. For 2017 and subsequent years, the recovery of and return on current and future capital investments under the STRIDE program are included in the annual base rate revenue adjustment under GRAM.

The i-CGP program authorized Atlanta Gas Light to spend $91 million through 2017 on projects to extend its pipeline facilities to serve customers in areas without pipeline access and create new economic development opportunities in Georgia. This program ended in 2017 and was replaced with a tariff to provide up to $15 million annually for Atlanta Gas Light to commit to strategic economic development projects.

The i-SRP program authorized $445 million of capital spending through 2017 for projects to upgrade Atlanta Gas Light's distribution system and LNG facilities in Georgia, improve its peak-day system reliability and operational flexibility, and create a platform to meet long-term forecasted growth. In August 2016, Atlanta Gas Light filed a petition with the Georgia PSC for approval of a four -year extension of its i-SRP seeking approval to invest an additional $177 million to improve and upgrade its core gas distribution system in years 2017 through 2020.

The i-VPR program authorized Atlanta Gas Light to spend $275 million through 2017 to replace 756 miles of aging plastic pipe that was installed primarily in the mid-1960s to the early 1980s. Atlanta Gas Light has identified approximately 3,300 miles of vintage plastic mains in its system that should be considered for potential replacement.

See "Base Rate Cases" herein for additional information.

The orders for the STRIDE programs provide for recovery of all prudent costs incurred in the performance of the program. Atlanta Gas Light will recover from end-use customers, through billings to Marketers, the costs related to the programs net of any cost savings from the programs. The regulatory asset represents recoverable incurred costs related to the programs that will be collected in future rates charged to customers through the rate riders. The future expected costs to be recovered through rates related to allowed, but not incurred costs, are recognized in an unrecognized ratemaking amount that is not reflected on the balance sheets. This allowed cost is primarily the equity return on the capital investment under the program. See "Unrecognized Ratemaking Amounts" herein for additional information.

Atlanta Gas Light capitalizes and depreciates the capital expenditure costs incurred from the STRIDE programs over the life of the assets. Operations and maintenance costs are expensed as incurred. Recoveries, which are recorded as revenue, are based on a formula that allows Atlanta Gas Light to recover operations and maintenance costs in excess of those included in its current base rates, depreciation, and an allowed rate of return on capital expenditures. However, Atlanta Gas Light is allowed the recovery of carrying costs on the under recovered balance resulting from the timing difference.

*Elizabethtown Gas*

Elizabethtown Gas' 2013 extension of the Aging Infrastructure Replacement (AIR) enhanced infrastructure program allowed for infrastructure investment of $115 million over four years and was focused on the replacement of aging cast iron in its pipeline system. Carrying charges on the additional capital spend are being accrued and deferred for regulatory purposes at a weighted average cost of capital of 6.65% . Effective July 1, 2017, investments under this program, which ended September 30, 2017, are being recovered through base rate revenues. See "Base Rate Cases" herein for additional information.

In 2015, Elizabethtown Gas filed the Safety, Modernization and Reliability Tariff plan with the New Jersey BPU seeking approval to invest more than $1.1 billion to replace 630 miles of vintage cast iron, steel, and copper pipeline, as well as 240 regulator stations. During the first quarter 2018, Elizabethtown Gas withdrew this filing in response to a proposed rule by the New Jersey BPU to incentivize utilities to accelerate investment in infrastructure replacement programs that enhance reliability, resiliency, and/or safety of the distribution system. The ultimate outcome of this matter cannot be determined at this time.

*Virginia Natural Gas*

In 2012, the Virginia Commission approved the Steps to Advance Virginia's Energy (SAVE) program, an accelerated infrastructure replacement program, to be completed over a five -year period. This program included a maximum allowance for capital expenditures of $25 million per year, not to exceed $105 million in total.

In March 2016, the Virginia Commission approved an extension to the SAVE program for Virginia Natural Gas to replace more than 200 miles of aging pipeline infrastructure and invest up to $30 million in 2016 and up to $35 million annually through 2021.

The SAVE program is subject to annual review by the Virginia Commission. In conjunction with the base rate case order issued by the Virginia Commission on December 21, 2017, Virginia Natural Gas is recovering the portion of these program costs incurred prior to September 1, 2017 through base rates. See "Base Rate Cases" herein for additional information.

*Florida City Gas*

In 2015, the Florida PSC approved Florida City Gas' Safety, Access, and Facility Enhancement program, under which costs incurred for replacing aging pipes are recovered through a rate rider with annual adjustments and true-ups. Under the program, Florida City Gas is authorized to spend $105 million over a 10 -year period on infrastructure relocation and enhancement projects.

***PRP Settlement***

In 2015, Atlanta Gas Light received a final order from the Georgia PSC for a rate true-up of allowed unrecovered revenue through 2014 related to its PRP. This order allows Atlanta Gas Light to recover $144 million of the $178 million previously unrecovered program revenue. The remaining $34 million requested related primarily to previously unrecognized ratemaking amounts and did not have a material impact on the Company's financial statements. The Company also recognized $1 million of interest expense and $5 million in operations and maintenance expense related to the PRP on the Company's statements of income for the predecessor year ended December 31, 2015. See "Unrecognized Ratemaking Amounts" herein for additional information.

As a result of the PRP settlement, Atlanta Gas Light began recovering incremental PRP surcharge amounts through three phased in increases in addition to its previously existing PRP surcharge amount, which was established to address recovery of the unrecovered PRP balance of $144 million in 2015 and the estimated amounts to be earned under the program through 2025. The initial incremental surcharge of approximately $15 million annually was effective in October 2015, with additional annual increases of approximately $15 million in each of October 2016 and 2017. The final increase scheduled for October 2017 was included in the implementation of GRAM in March 2017. The under recovered balance is the result of the continued revenue requirement earned under the program offset by the existing and incremental PRP surcharges. The unrecovered balance at December 31, 2017 was $187 million , including $104 million of unrecognized equity return. The PRP surcharge will remain in effect until the earlier of the full recovery of the under recovered amount or December 31, 2025. See "Base Rate Cases" herein for additional information on GRAM.

One of the capital projects under the PRP experienced construction issues and Atlanta Gas Light was required to complete mitigation work prior to placing it in service. These mitigation costs will be included in future base rates in 2018. Provisions in the order resulted in the recognition of $5 million in operations and maintenance expense for the predecessor year ended December 31, 2015 on the Company's statements of income. In 2017, Atlanta Gas Light recovered $20 million from the settlement of contractor litigation claims and continues to pursue contractual and legal claims against a third-party contractor. Mitigation costs recovered through the legal process are retained by Atlanta Gas Light. The ultimate outcome of this matter cannot be determined at this time.

***Base Rate Cases***

*Settled Base Rate Cases*

On February 21, 2017, the Georgia PSC approved GRAM and a $20 million increase in annual base rate revenues for Atlanta Gas Light, effective March 1, 2017. GRAM adjusts base rates annually, up or down, using an earnings band based on the previously approved ROE of 10.75% and does not collect revenue through special riders and surcharges. Atlanta Gas Light adjusts rates up to the lower end of the band of 10.55% and adjusts rates down to the higher end of the band of 10.95% . Various infrastructure programs previously authorized by the Georgia PSC under Atlanta Gas Light's STRIDE program, which include the i-VPR and i-SRP, will continue under GRAM and the recovery of and return on the infrastructure program investments will be included in annual base rate adjustments. The Georgia PSC will review Atlanta Gas Light's performance annually under GRAM.

Pursuant to the GRAM approval, Atlanta Gas Light and the staff of the Georgia PSC agreed to a variation to the i-CGP that was formerly part of Atlanta Gas Light's STRIDE program. As a result, a new tariff was created, effective October 10, 2017, to provide up to $15 million annually for Atlanta Gas Light to commit to strategic economic development projects. Projects under this tariff must be approved by the Georgia PSC.

Beginning with the next rate adjustment in June 2018, Atlanta Gas Light's recovery of the previously unrecovered Pipeline Replacement Program revenue through 2014, as well as the mitigation costs associated with the Pipeline Replacement Program that were not previously included in its rates, will also be included in GRAM. In connection with the GRAM approval, the last monthly Pipeline Replacement Program surcharge increase became effective March 1, 2017.

On June 30, 2017, the New Jersey BPU approved a settlement that provides for a $13 million increase in annual base rate revenues, effective July 1, 2017, based on a ROE of 9.6% . Also included in the settlement was a new composite depreciation rate that is expected to result in a $3 million annual reduction of depreciation. See Note 11 under "Proposed Sale of Elizabethtown Gas and Elkton Gas" for information on the proposed sale of Elizabethtown Gas.

On December 21, 2017, the Virginia Commission approved a settlement for a $34 million increase in annual base rate revenues, effective September 1, 2017, including $13 million related to the recovery of investments under the SAVE program. See "Regulatory Infrastructure Programs" herein for additional information. An authorized ROE range of 9.0% to 10.0% with a midpoint of 9.5% will be used to determine the revenue requirement in any filing, other than for a change in base rates.

On January 31, 2018, the Illinois Commission approved a $137 million increase in annual base rate revenues, including $93 million related to the recovery of investments under the Investing in Illinois program, effective February 8, 2018, based on a ROE of 9.8% .

*Pending Base Rate Cases*

On October 23, 2017, Florida City Gas filed a general base rate case with the Florida PSC requesting a $19 million increase in annual base rate revenues. On January 29, 2018, Florida City Gas filed an update to incorporate the effects of the Tax Reform Legislation that, if approved, would reduce the requested base rate revenues by $4 million . The requested increase is based on a 2018 projected test year and a ROE of 11.25% . The requested increase includes $3 million related to the recovery of investments under SAFE that are currently being recovered through a surcharge. Additionally, Florida City Gas requested an interim rate increase of $5 million annually that was approved and became effective January 12, 2018, subject to refund. The Florida PSC is expected to rule on the requested increase in mid-2018.

On December 1, 2017, Atlanta Gas Light filed its 2018 annual rate adjustment with the Georgia PSC. If approved, annual base rate revenues will increase by $22 million , effective June 1, 2018. Atlanta Gas Light will file a revised rate adjustment to incorporate the effects of the Tax Reform Legislation in the first quarter 2018. The Georgia PSC is expected to rule on the revised requested increase in the second quarter 2018.

On February 15, 2018, Chattanooga Gas filed a general base rate case with the Tennessee Public Utility Commission requesting a $7 million increase in annual base rate revenues. The requested increase, which incorporated the effects of the Tax Reform Legislation, was based on a projected test year ending June 30, 2019 and a ROE of 11.25% . The Tennessee Public Utility Commission is expected to rule on the requested increase in the third quarter 2018.

The ultimate outcome of these pending base rate cases cannot be determined at this time.

***Other***

The New Jersey BPU, Virginia Commission, Tennessee Public Utility Commission, and Maryland PSC each issued an order effective January 1, 2018 that requires utilities in their respective states to track as a regulatory liability the impact of the Tax Reform Legislation, including the reduction in the corporate income tax rate to 21% and the impact of excess deferred income taxes. The New Jersey BPU's order requires Elizabethtown Gas to file by March 2, 2018 proposed revised base rates with an April 1, 2018 interim effective date and a July 1, 2018 final effective date. Virginia Natural Gas will address the Virginia Commission's order in its Annual Information Filing, which will be filed by July 1, 2018. The Tennessee Public Utility Commission's order required Chattanooga Gas to file proposals to reduce rates or make other ratemaking adjustments to account for the impact of the Tax Reform Legislation. Chattanooga Gas made the required filing as part of its February 15, 2018 general base rate case filing. The Maryland PSC's order required Elkton Gas to file an explanation of the impact of the Tax Reform Legislation on its expenses and revenues, as well as when and how it expects to pass through to its customers those effects. Elkton Gas made the required filing on February 15, 2018 and will reduce annual base rates by $0.1 million effective April 1, 2018. Credits will be issued to customers for the impact of the Tax Reform Legislation from January 2018 through March 2018.

The Illinois Commission issued an order effective January 25, 2018 that requires utilities in the state to record the impacts of the Tax Reform Legislation, including the reduction in the corporate income tax rate to 21% and the impact of excess deferred income taxes, as a regulatory liability. On February 20, 2018, the Illinois Commission granted Nicor Gas' application for rehearing to file revised base rates and tariffs, which Nicor Gas expects to file by the end of the second quarter 2018.

The ultimate outcome of these matters cannot be determined at this time.

***energySMART***

In 2014, the Illinois Commission approved Nicor Gas' energySMART through 2017, which outlined energy efficiency program offerings and therm reduction goals, and subsequently extended the program to 2021. Through December 31, 2017, Nicor Gas spent $107 million of the initial authorized expenditure of $113 million . A new four -year program began on January 1, 2018, with an additional authorized expenditure of $160 million .

***Unrecognized Ratemaking Amounts***

The following table illustrates the Company's authorized ratemaking amounts that are not recognized on its balance sheets. These amounts are primarily composed of an allowed equity rate of return on assets associated with certain of the Company's regulatory infrastructure programs. These amounts will be recognized as revenues in the Company's financial statements in the periods they are billable to customers, the majority of which will be recovered by 2025.

| | **December 31, 2017** | December 31, 2016 |
|---|---|---|
| | *(in millions)* | |
| Atlanta Gas Light | **$ 104** | $ 110 |
| Virginia Natural Gas | **11** | 11 |
| Elizabethtown Gas (*) | **8** | 6 |
| Nicor Gas | **2** | 2 |
| Total | **$ 125** | $ 129 |

(*) See Note 11 under "Proposed Sale of Elizabethtown Gas and Elkton Gas" for information on the pending asset sale.

**Other Matters**

A wholly-owned subsidiary of the Company owns and operates a natural gas storage facility consisting of two salt dome caverns in Louisiana. Periodic integrity tests are required in accordance with rules of the Louisiana Department of Natural Resources (DNR). In August 2017, in connection with an ongoing integrity project, updated seismic mapping indicated the proximity of one of the caverns to the edge of the salt dome may be less than the required minimum and could result in the Company retiring the cavern early. At December 31, 2017, the facility's property, plant, and equipment had a net book value of $112 million , of which the cavern itself represents approximately 20% . A potential early retirement of this cavern is dependent upon several factors including compliance with an order from the Louisiana DNR detailing the requirements to place the cavern back in service, which includes, among other things, obtaining core samples to determine the composition of the sheath surrounding the edge of the salt dome.

The cavern continues to maintain its pressures and overall structural integrity. These events were considered in connection with the Company's annual long-lived asset impairment analysis, which determined there was no impairment as of December 31, 2017. Any changes in results of monitoring activities, rates at which expiring capacity contracts are re-contracted, timing of placing the cavern back in service, or Louisiana DNR requirements could trigger impairment. Further, early retirement of the cavern could trigger impairment of other long-lived assets associated with the natural gas storage facility. The ultimate outcome of this matter cannot be determined at this time, but could have a material impact on the Company's financial statements.

## 4 . JOINT OWNERSHIP AGREEMENTS

In 2014, the Company entered into a construction and ownership arrangement associated with the Dalton Pipeline through which the Company has a 50% undivided ownership interest jointly with The Williams Companies, Inc. in the 115 -mile Dalton Pipeline to serve as an extension of the Transco natural gas pipeline system into northwest Georgia. The Company also entered into an agreement to lease its 50% undivided ownership in the Dalton Pipeline that became effective when it was placed in service on August 1, 2017 . Under the lease, the Company will receive approximately $26 million annually for an initial term of 25 years . The lessee is responsible for maintaining the pipeline during the lease term and for providing service to transportation customers under its FERC-regulated tariff. At December 31, 2017 , the net book value of the Company's 50% share of the pipeline was $252 million and is reflected in total property, plant, and equipment in the balance sheet. At December 31, 2016, the net book value of the Company's 50% share of the pipeline was $124 million and is reflected in construction work in progress in the balance sheet.

### Variable Interest Entities

SouthStar, previously a joint venture owned 85% by the Company and 15% by Piedmont, was the only VIE for which the Company was the primary beneficiary, prior to October 2016 when the Company completed its purchase of Piedmont's remaining interest in SouthStar.

In 2015, Georgia Natural Gas Company (GNG), a 100% -owned, direct subsidiary of the Company, notified Piedmont of its election, pursuant to a change in control of SouthStar, to purchase Piedmont's 15% interest in SouthStar at fair market value. This purchase was contingent upon the closing of the merger between Piedmont and Duke Energy Corporation (Duke Energy). In October 2016, after Piedmont and Duke Energy completed their merger, GNG completed its purchase of Piedmont's interest in SouthStar and paid a purchase price of $160 million and $15 million for Piedmont's share of SouthStar's 2016 earnings through the date of acquisition.

At December 31, 2015, the Company presented the noncontrolling interest related to Piedmont's interest in SouthStar as a component in equity. During the first quarter 2016, the Company reclassified its noncontrolling interest, whose redemption was beyond the Company's control, as a contingently redeemable noncontrolling interest. Upon Piedmont and Duke Energy obtaining the necessary merger approval, the Company deemed this noncontrolling interest to be mandatorily redeemable and reclassified it to a current liability during the third quarter 2016. The roll-forwards of the redeemable noncontrolling interest for the successor period of July 1, 2016 through December 31, 2016 and the predecessor period of January 1, 2016 through June 30, 2016 are detailed below:

| **Predecessor –** | | *(in millions)* |
|---|---|---|
| Balance at December 31, 2015 | $ | — |
| Reclassification of noncontrolling interest to contingently redeemable noncontrolling interest | | 46 |
| Net income attributable to noncontrolling interest | | 14 |
| Distribution to noncontrolling interest | | (19) |
| Balance at June 30, 2016 | $ | 41 |
| **Successor –** | | *(in millions)* |
| Balance at July 1, 2016 | $ | 174 |
| Reclassification of contingently redeemable noncontrolling interest to mandatorily redeemable noncontrolling interest | | (174) |
| Balance at December 31, 2016 | $ | — |

The Company's cash flows used for financing activities included SouthStar's distribution to Piedmont for its portion of SouthStar's annual earnings from the previous year, which generally occurred in the first quarter of each year. For the successor period of July 1, 2016 through December 31, 2016 , SouthStar made a distribution of $15 million upon completion of the purchase of Piedmont's interest in SouthStar. For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 , SouthStar distributed to Piedmont $19 million and $18 million , respectively.

**Equity Method Investments**

The carrying amounts of the Company's equity method investments as of December 31, 2017 and 2016 and related income from those investments for the successor periods of the year ended December 31, 2017 and July 1, 2016 through December 31, 2016 and predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 were as follows:

| **Balance Sheet Information** | **December 31, 2017** | December 31, 2016 |
|---|---|---|
| | *(in millions)* | |
| SNG (*) | **$ 1,262** | $ 1,394 |
| Triton | **42** | 44 |
| Horizon Pipeline | **30** | 30 |
| PennEast Pipeline | **57** | 22 |
| Atlantic Coast Pipeline | **41** | 33 |
| Pivotal JAX LNG, LLC | **44** | 16 |
| Other | **1** | 2 |
| Total | **$ 1,477** | $ 1,541 |

(*) Includes a $104 million decrease at December 31, 2017 related to the impact of the Tax Reform Legislation and new income tax apportionment factors in several states resulting from the Company's inclusion in the consolidated Southern Company state tax filings.

| | Successor | | Predecessor | |
|---|---|---|---|---|
| **Income Statement Information** | **Year ended December 31, 2017** | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | Year ended December 31, 2015 |
| | *(in millions)* | | *(in millions)* | |
| SNG | **$ 88** | $ 56 | $ — | $ — |
| Triton | **4** | 2 | 1 | 4 |
| Horizon Pipeline | **2** | 1 | 1 | 2 |
| Atlantic Coast Pipeline | **6** | 1 | — | — |
| PennEast Pipeline | **6** | — | — | — |
| Total | **$ 106** | $ 60 | $ 2 | $ 6 |

**NOTES (continued)**
**Southern Company Gas and Subsidiary Companies 2017 Annual Report**

***SNG***

In September 2016, the Company, through a wholly-owned, indirect subsidiary, acquired a 50% equity interest in SNG, which is accounted for as an equity method investment. See Note 11 under "Investment in SNG" for additional information. Selected financial information of SNG as of December 31, 2017 and 2016 and for the year ended December 31, 2017 and for the period September 1, 2016 through December 31, 2016 is as follows:

| | As of December 31, | |
|---|---|---|
| **Balance Sheet Information** | **2017** | 2016 |
| | *(in millions)* | |
| Current assets | **$ 82** | $ 95 |
| Property, plant, and equipment | **2,439** | 2,451 |
| Deferred charges and other assets | **121** | 129 |
| Total Assets | **$ 2,642** | $ 2,675 |
| | | |
| Current liabilities | **$ 110** | $ 588 |
| Long-term debt | **1,102** | 706 |
| Other deferred charges and other liabilities | **76** | 22 |
| Total Liabilities | **$ 1,288** | $ 1,316 |
| | | |
| Total Stockholders' Equity | **1,354** | 1,359 |
| Total Liabilities and Stockholders' Equity | **$ 2,642** | $ 2,675 |

| **Income Statement Information** | **Year ended December 31, 2017** | September 1, 2016 through December 31, 2016 |
|---|---|---|
| | *(in millions)* | |
| Revenues | **$ 544** | $ 230 |
| Operating income | **246** | 138 |
| Net income | **$ 175** | $ 115 |

**Other Investments**

***Triton***

The Company has an investment in Triton, a cargo container leasing company, which is aggregated into its all other segment. Container equipment that is acquired by Triton is accounted for in tranches as defined in Triton's operating agreement and investors make capital contributions to Triton to invest in each of the tranches. As of December 31, 2017 , the Company had invested in seven tranches established by Triton.

***Horizon Pipeline***

The Company owns an   interest in a joint venture with Natural Gas Pipeline Company of America that is regulated by the FERC. Horizon Pipeline operates a 70 -mile natural gas pipeline from Joliet, Illinois to near the Wisconsin/Illinois border. Nicor Gas typically contracts for 70% to 80% of the total annual capacity.

***PennEast Pipeline***

In 2014, the Company entered into a partnership in which it holds a 20% ownership interest in an interstate pipeline company formed to develop and operate a 118 -mile natural gas pipeline between New Jersey and Pennsylvania. The initial transportation capacity of 1.0 billion cubic feet (Bcf) per day, is under long-term contracts, mainly by public utilities and other market-serving entities, such as electric generation companies, in New Jersey, Pennsylvania, and New York. On January 19, 2018, the PennEast Pipeline project received FERC approval.

***Atlantic Coast Pipeline***

In 2014, the Company entered into a project in which it holds a 5% ownership interest in an interstate pipeline company formed to develop and operate a 594 -mile natural gas pipeline in North Carolina, Virginia, and West Virginia with initial transportation capacity of 1.5 Bcf per day. On October 13, 2017, the Atlantic Coast Pipeline project received FERC approval.

***Pivotal JAX LNG, LLC***

The Company owns a 50% interest in a planned LNG liquefaction and storage facility in Jacksonville, Florida. Once construction is complete and the facility is operational, it will be outfitted with a 2.0 million gallon storage tank with the capacity to produce in excess of 120,000 gallons of LNG per day.

## 5. INCOME TAXES

Subsequent to the Merger, Southern Company files a consolidated federal income tax return and various combined and separate state income tax returns on behalf of the Company. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability. Prior to the Merger, the Company filed a U.S. federal consolidated income tax return and various state income tax returns.

### Federal Tax Reform Legislation

Following the enactment of the Tax Reform Legislation, the SEC staff issued Staff Accounting Bulletin 118 – "Income Tax Accounting Implications of the Tax Cuts and Jobs Act" (SAB 118), which provides for a measurement period of up to one year from the enactment date to complete accounting under GAAP for the tax effects of the legislation. Due to the complex and comprehensive nature of the enacted tax law changes, and their application under GAAP, the Company considers all amounts recorded in the financial statements as a result of the Tax Reform Legislation to be "provisional" as discussed in SAB 118 and subject to revision. The Company is awaiting additional guidance from industry and income tax authorities in order to finalize its accounting. The ultimate impact of the Tax Reform Legislation on deferred income tax assets and liabilities and the related regulatory assets and liabilities cannot be determined at this time.

### Current and Deferred Income Taxes

Details of income tax provisions are as follows:

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | **Year ended December 31, 2017** | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | Year ended December 31, 2015 |
| | *(in millions)* | | *(in millions)* | |
| Federal — | | | | |
| Current | **$ 103** | $ — | $ 67 | $ (13) |
| Deferred | **170** | 65 | 8 | 198 |
| | **273** | 65 | 75 | 185 |
| State — | | | | |
| Current | **27** | (16) | 12 | 10 |
| Deferred | **67** | 27 | — | 18 |
| | **94** | 11 | 12 | 28 |
| Total | **$ 367** | $ 76 | $ 87 | $ 213 |

Net cash payments (refunds) for income taxes for the successor periods of the year ended December 31, 2017 and July 1, 2016 through December 31, 2016 and the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 were $72 million , $23 million , $(100) million , and $(26) million , respectively.

**NOTES (continued)**
**Southern Company Gas and Subsidiary Companies 2017 Annual Report**

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

| | 2017 | 2016 |
|---|---|---|
| | *(in millions)* | |
| Deferred tax liabilities — | | |
| Accelerated depreciation | **$ 1,436** | $ 1,954 |
| Property basis differences | **204** | 311 |
| Regulatory assets associated with employee benefit obligations | **79** | 125 |
| Other | **208** | 164 |
| Total | **1,927** | 2,554 |
| Deferred tax assets — | | |
| Federal net operating loss | **92** | 59 |
| Federal effect of state deferred taxes | **54** | 42 |
| Employee benefit obligations | **185** | 165 |
| Regulatory liability associated with the Tax Reform Legislation (not subject to normalization) | **295** | — |
| Other | **223** | 332 |
| Total | **849** | 598 |
| Less valuation allowances | **(11)** | (19) |
| Total, net of valuation allowances | **838** | 579 |
| Accumulated deferred income taxes, net | **$ 1,089** | $ 1,975 |

The implementation of the Tax Reform Legislation significantly reduced accumulated deferred income taxes, partially offset by bonus depreciation provisions in the Protecting Americans from Tax Hikes Act. The Tax Reform Legislation also significantly increased tax-related regulatory liabilities.

At December 31, 2017 , the tax-related regulatory liabilities to be credited to customers were $1.1 billion . These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized ITCs.

Deferred federal and state ITCs are amortized over the average life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $4 million and $1 million for the successor periods of the year ended December 31, 2017 and July 1, 2016 through December 31, 2016 and for the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 , were $1 million and $2 million , respectively. At December 31, 2017 , all ITCs available to reduce federal income taxes payable had been utilized.

**Effective Tax Rate**

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | **Year ended December 31, 2017** | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | Year ended December 31, 2015 |
| Federal statutory rate | **35.0%** | 35.0% | 35.0% | 35.0% |
| State income tax, net of federal deduction | **4.0** | 4.0 | 3.5 | 3.4 |
| Tax Reform Legislation | **15.0** | — | — | — |
| State tax legislation and rate changes | **6.2** | — | — | — |
| Other | **—** | 1.0 | (0.9) | (2.0) |
| Effective income tax rate | **60.2%** | 40.0% | 37.6% | 36.4% |

The principal differences in the Company's effective tax rate from December 31, 2016 to December 31, 2017 include the impact of the Tax Reform Legislation, the Illinois income tax legislation enacted in the third quarter 2017, new income tax apportionment factors in several states resulting from the Company's inclusion in the consolidated Southern Company state tax filings, the disallowance of certain nondeductible Merger-related expenses associated with change-in-control compensation charges, and an increase in earnings before income taxes.

**Unrecognized Tax Benefits**

The Company has no unrecognized tax benefits for any period presented.

The Company classifies interest on tax uncertainties as interest expense; however, the Company had no accrued interest or penalties for unrecognized tax benefits for any period presented.

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months. The settlement of federal and state audits could impact the balances. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

On July 1, 2016, the Company became a wholly-owned subsidiary of Southern Company, which is a participant in the Compliance Assurance Process of the IRS. The IRS has finalized its audits of Southern Company's consolidated federal tax returns through 2016. However, the pre-Merger Southern Company Gas 2014, 2015, and June 30, 2016 federal tax returns are currently under audit. The audits for the Company by any state have either concluded, or the statute of limitations has expired with respect to income tax examinations, for years prior to 2011.

## 6 . FINANCING

The Company's 100% -owned subsidiary, Southern Company Gas Capital, was established to provide for certain of the Company's ongoing financing needs through a commercial paper program, the issuance of various debt, hybrid securities, and other financing arrangements. Southern Company Gas fully and unconditionally guarantees all debt issued by Southern Company Gas Capital and the gas facility revenue bonds issued by Pivotal Utility Holdings. Additionally, substantially all of Nicor Gas' properties are subject to the lien of the indenture securing its first mortgage bonds. Nicor Gas is not permitted by regulation to make loans to affiliates or utilize Southern Company Gas Capital for its financing needs.

**Securities Due Within One Year**

The current portion of long-term debt is composed of the portion of its long-term debt due within the next 12 months. At December 31, 2017 , the Company had $157 million of senior notes due within one year, including the fair value adjustment attributable to the application of acquisition accounting. At December 31, 2016 , the Company had $22 million of medium-term notes due within one year.

**Long-Term Debt**

Long-term debt of the Company at December 31, 2017 and 2016 consisted of Series A, Series B, and Series C medium-term notes of Atlanta Gas Light; senior notes of Southern Company Gas Capital; first mortgage bonds of Nicor Gas; and gas facility revenue bonds of Pivotal Utility Holdings.

Maturities through 2022 applicable to total long-term debt are as follows: $155 million in 2018 ; $350 million in 2019 ; $330 million in 2021 ; $93 million in 2022 ; and $4.6 billion thereafter. There are no material scheduled maturities in 2020.

***Medium-Term Notes***

In July 2017, Atlanta Gas Light repaid at maturity $22 million of medium-term notes. The amount of medium-term notes outstanding at December 31, 2017 and 2016 was $159 million and $181 million , respectively, including securities due within one year.

***Senior Notes***

In May 2017, Southern Company Gas Capital issued $450 million aggregate principal amount of Series 2017A 4.40% Senior Notes due May 30, 2047. The proceeds were used to repay the Company's short-term indebtedness and for general corporate purposes. The amount of senior notes outstanding at December 31, 2017 and 2016 was $4.2 billion and $3.7 billion , respectively, including securities due within one year.

***First Mortgage Bonds***

Nicor Gas had $1.0 billion and $625 million of first mortgage bonds outstanding at December 31, 2017 and 2016 , respectively. These bonds have been issued with maturities ranging from 2019 to 2057.

On August 10, 2017, Nicor Gas issued $100 million aggregate principal amount of First Mortgage Bonds 3.03% Series due August 10, 2027 and $100 million aggregate principal amount of First Mortgage Bonds 3.62% Series due August 10, 2037. On November 1, 2017, Nicor Gas issued $100 million aggregate principal amount of First Mortgage Bonds 3.85% Series due August 10, 2047 and $100 million aggregate principal amount of First Mortgage Bonds 4.00% Series due August 10, 2057. The proceeds were used to repay short-term indebtedness incurred under the Nicor Gas commercial paper program and for other working capital needs.

***Gas Facility Revenue Bonds***

Pivotal Utility Holdings is party to a series of loan agreements with the New Jersey Economic Development Authority and Brevard County, Florida under which five series of gas facility revenue bonds have been issued with maturities ranging from 2022 to 2033. These revenue bonds are issued by state agencies or counties to investors, and proceeds from each issuance then are loaned to Pivotal Utility Holdings. The amount of gas facility revenue bonds outstanding at December 31, 2017 and 2016 was $200 million .

The Elizabethtown Gas asset sale agreement requires that bonds representing $180 million of the total that are currently eligible for redemption at par be redeemed on or prior to consummation of the sale. The ultimate outcome of this matter cannot be determined at this time. See Note 11 under "Proposed Sale of Elizabethtown Gas and Elkton Gas" for additional information.

**Parent Company Note**

On January 4, 2018, Southern Company Gas issued a floating rate promissory note to Southern Company in an aggregate principal amount of $100 million due July 31, 2018, bearing interest based on one-month LIBOR.

**Dividend Restrictions**

By regulation, Nicor Gas is restricted, to the extent of its retained earnings balance, in the amount it can dividend or loan to affiliates and is not permitted to make money pool loans to affiliates. The New Jersey BPU restricts the amount Elizabethtown Gas can dividend to its parent company to 70% of its quarterly net income. Additionally, as stipulated in the New Jersey BPU's order approving the Merger, the Company is prohibited from paying dividends to its parent company, Southern Company, if the Company's senior unsecured debt rating falls below investment grade. As of December 31, 2017 , the amount of subsidiary retained earnings restricted for dividend payment totaled $719 million .

**Bank Credit Arrangements**

***Credit Facilities***

At December 31, 2017 , committed credit arrangements with banks were as follows:

| Company | Expires 2022 | Unused |
|---|---|---|
| | *(in millions)* | |
| Southern Company Gas Capital | $ 1,400 | $ 1,390 |
| Nicor Gas | 500 | 500 |
| Total | $ 1,900 | $ 1,890 |

In May 2017, Southern Company Gas Capital and Nicor Gas terminated their existing credit arrangements for $1.3 billion and $700 million , respectively, which were to mature in 2017 and 2018, and entered into a new multi-year credit arrangement (Facility) currently allocated for $1.4 billion and $500 million , respectively, with a maturity date of 2022, as reflected in the table above. Pursuant to the Facility, the allocations between Southern Company Gas Capital and Nicor Gas may be adjusted.

The Facility contains a covenant that limits the ratio of debt to capitalization (as defined in each facility) to a maximum of 70% for each of the Company and Nicor Gas and contains a cross-acceleration provision to other indebtedness (including guarantee obligations) of the applicable company. Such cross-acceleration provision to other indebtedness would trigger an event of default of the applicable company if the Company or Nicor Gas defaulted on indebtedness, the payment of which was then accelerated. At December 31, 2017 , both companies were in compliance with such covenant. The Facility does not contain a material adverse change clause at the time of borrowings.

### *Commercial Paper Programs*

The Company maintains commercial paper programs at Southern Company Gas Capital and at Nicor Gas that consist of short-term, unsecured promissory notes. Nicor Gas' commercial paper program supports working capital needs at Nicor Gas as Nicor Gas is not permitted to make money pool loans to affiliates. All of the Company's other subsidiaries benefit from Southern Company Gas Capital's commercial paper program. Commercial paper is included in notes payable in the balance sheets.

Details of commercial paper borrowings outstanding were as follows:

| | Short-term Debt at the End of the Period | | |
|---|---|---|---|
| | Amount Outstanding | | Weighted Average Interest Rate |
| | *(in millions)* | | |
| **December 31, 2017:** | | | |
| Southern Company Gas Capital | **$** | **1,243** | **1.73%** |
| Nicor Gas | | **275** | **1.83** |
| Total | **$** | **1,518** | **1.75%** |
| **December 31, 2016:** | | | |
| Southern Company Gas Capital | $ | 733 | 1.09% |
| Nicor Gas | | 524 | 0.95 |
| Total | $ | 1,257 | 1.03% |

## 7 . COMMITMENTS

### Pipeline Charges, Storage Capacity, and Gas Supply

Pipeline charges, storage capacity, and gas supply include charges recoverable through a natural gas cost recovery mechanism, or alternatively, billed to Marketers and demand charges associated with Sequent. The gas supply balance includes amounts for Nicor Gas' and SouthStar's gas commodity purchase commitments of 35 million mmBtu at floating gas prices calculated using forward natural gas prices at December 31, 2017 and valued at $101 million . The Company provides guarantees to certain gas suppliers for certain of its subsidiaries in support of payment obligations.

Expected future contractual obligations for pipeline charges, storage capacity, and gas supply that are not recognized on the balance sheets as of December 31, 2017 were as follows:

| | Pipeline Charges, Storage Capacity, and Gas Supply | |
|---|---|---|
| | *(in millions)* | |
| 2018 | $ | 813 |
| 2019 | | 552 |
| 2020 | | 416 |
| 2021 | | 375 |
| 2022 | | 339 |
| 2023 and thereafter | | 2,294 |
| Total | $ | 4,789 |

### Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Total rent expense was $15 million , $8 million , $6 million , and $12 million for the successor periods of the year ended December 31, 2017 and July 1, 2016 through December 31, 2016 and the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 , respectively. The Company includes any step rents, escalations, and lease concessions in its computation of minimum lease payments, which are recognized on a straight-line basis over the minimum lease terms.

As of December 31, 2017 , the Company's estimated minimum lease payments under operating leases were as follows:

| | Minimum Lease Payments | |
|---|---|---|
| | *(in millions)* | |
| 2018 | $ | 17 |
| 2019 | | 16 |
| 2020 | | 16 |
| 2021 | | 15 |
| 2022 | | 13 |
| 2023 and thereafter | | 26 |
| Total | $ | 103 |

**Financial Guarantees**

AGL Equipment Leasing Inc. (AEL), a wholly-owned subsidiary of the Company, holds the Company's interest in Triton and has an obligation to restore to zero any deficit in its equity account for income tax purposes in the unlikely event that Triton is liquidated and a deficit balance remains. This obligation continues for the life of the Triton partnerships. Any payment is effectively limited to the net assets of AEL, which were less than $1 million at December 31, 2017 . The Company believes the likelihood of any such payment by AEL is remote and, as such, no liability has been recorded for this obligation at December 31, 2017 .

## 8. STOCK COMPENSATION

### Successor

***Stock-Based Compensation***

Stock-based compensation primarily in the form of Southern Company performance share units and restricted stock units may be granted through the Omnibus Incentive Compensation Plan to certain levels of management within the Company. In 2017 , stock-based compensation granted to employees includes performance share units and restricted stock units. In 2016 , in conjunction with the Merger, stock-based compensation was granted to certain executives in the form of Southern Company restricted stock and performance share units. As of December 31, 2017 , there were 327 current and former employees participating in the performance share unit and restricted stock unit programs.

*Performance Share Units*

Performance share units granted to employees vest at the end of a three -year performance period. All unvested performance share units vest immediately upon a change in control where Southern Company is not the surviving corporation. Shares of Southern Company common stock are delivered to employees at the end of the performance period with the number of shares issued ranging from 0% to 200% of the target number of performance share units granted, based on achievement of the performance goals established by the Compensation Committee of the Southern Company Board of Directors.

Southern Company issues performance share units with performance goals based on three performance goals to employees. These include performance share units with performance goals based on the total shareholder return (TSR) for Southern Company common stock during the three-year performance period as compared to a group of industry peers, performance share units with performance goals based on Southern Company's cumulative earnings per share (EPS) over the performance period, and performance share units with performance goals based on Southern Company's equity-weighted ROE over the performance period.

The total target grant date fair value of the stock compensation awards granted was comprised 20% each of EPS-based awards and ROE-based awards and 30% each of TSR-based awards and restricted stock units.

The fair value of TSR-based performance share unit awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's common stock among the industry peers over the performance period. Southern Company recognizes compensation expense on a straight-line basis over the three -year performance period without remeasurement.

The fair values of the EPS-based awards and the ROE-based awards are based on the closing stock price of Southern Company common stock on the date of the grant. Compensation expense for the EPS-based and ROE-based awards is generally recognized ratably over the three-year performance period initially assuming a 100% payout at the end of the performance period. Employees become immediately vested in the TSR-based performance share units, along with the EPS-based and ROE-based awards, upon retirement. As a result, compensation expense for employees that are retirement eligible at the grant date is recognized immediately while compensation expense for employees that become retirement eligible during the vesting period is recognized over the period from grant date to the date of retirement eligibility. The expected payout related to the EPS-based and ROE-based awards is reevaluated annually with expense recognized to date increased or decreased based on the number of shares currently expected to be issued. Unlike the TSR-based awards, the compensation expense ultimately recognized for the EPS-based awards and the ROE-based awards will be based on the actual number of shares issued at the end of the performance period.

For the year ended December 31, 2017 , employees of the Company were granted 0.3 million performance share units. The weighted average grant-date fair value of TSR-based performance share units granted during 2017 , determined using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period, was $49.27 . The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2017 was $49.22 .

For the year ended December 31, 2017 , total compensation cost for performance share units recognized in income was $8 million with the related tax benefit also recognized in income of $3 million . The compensation cost related to the grant of Southern Company performance share units to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2017 , $6 million of total unrecognized compensation cost related to performance share award units will be recognized over a weighted-average period of approximately 21 months.

*Restricted Stock Units*

Stock-based compensation granted to employees included restricted stock units in addition to performance share units. One-third of the restricted stock units granted to employees vest each year throughout a three -year service period. All unvested restricted stock units vest immediately upon a change in control where Southern Company is not the surviving corporation. Shares of Southern Company common stock are delivered to employees at the end of the vesting period.

The fair value of restricted stock units is based on the closing stock price of Southern Company common stock on the date of the grant. Since one-third of the restricted stock units vest each year throughout a three -year service period, compensation expense for restricted stock unit awards is generally recognized over the corresponding one -, two -, or three -year period. Employees become immediately vested in the restricted stock units upon retirement. As a result, compensation expense for employees that are retirement eligible at the grant date is recognized immediately while compensation expense for employees that become retirement eligible during the vesting period is recognized over the period from grant date to the date of retirement eligibility.

For the year ended December 31, 2017 , employees of the Company were granted 0.1 million restricted stock units. The weighted average grant-date fair value of restricted stock units granted during 2017 was $49.23 .

For the year ended December 31, 2017 , total compensation cost for restricted stock units recognized in income was $4 million with the related tax benefit also recognized in income of $2 million . The compensation cost related to the grant of Southern Company restricted stock units to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2017 , $1 million of total unrecognized compensation cost related to restricted stock units will be recognized over a weighted-average period of approximately 13 months.

***Merger Stock Compensation***

At the effective time of the Merger, each share of Southern Company Gas common stock, other than certain excluded shares, was converted into the right to receive $66 in cash, without interest. Also at the effective time of the Merger:

- Southern Company Gas' outstanding restricted stock units, restricted stock awards, and non-employee director stock awards were deemed fully vested and were canceled and converted into the right to receive an amount in cash equal to the product of (i) the total number of shares of Southern Company Gas' common stock subject to such award and (ii) the Merger consideration of $66 per share;
- Southern Company Gas' outstanding stock options, all of which were fully vested, were canceled and converted into the right to receive an amount in cash equal to the product of (i) the total number of shares of Southern Company Gas' common stock subject to such options and (ii) the excess of the Merger consideration of $66 per share over the applicable exercise price per share of such options; and
- each outstanding award of a performance share unit was converted into an award of Southern Company's restricted stock units (restricted stock awards).

In conjunction with the Merger, stock-based compensation, in the form of Southern Company restricted stock and performance share units, was granted to certain executives of the Company through the Southern Company Omnibus Incentive Compensation Plan.

*Southern Company Restricted Stock Awards*

Under the terms of the restricted stock awards, the employees received a specified number of restricted stock units that vest when the employees have satisfied the requisite service period(s) at which time the employee receives Southern Company common stock. The terms of the award require the employee to be continuously employed through the original three -year vesting schedule of the award being replaced.

For the successor period ended December 31, 2016 , employees of the Company were granted 0.7 million restricted stock units. The grant-date fair value of the restricted stock units granted was $53.83 , based on the closing stock price of Southern Company common stock on the date of the grant. As a portion of the fair value of the award related to pre-combination service, the grant date fair value was allocated to pre- or post-combination service and accounted for as Merger consideration or compensation cost, respectively. Approximately $13 million of the grant date fair value was allocated to Merger consideration. The remaining fair value of $12 million is being recognized as compensation expense on a straight-line basis over the remaining vesting period.

The compensation cost related to the grant of restricted stock units to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. For the successor year ended December 31, 2017 and the successor period of July 1, 2016 through December 31, 2016 , total compensation cost for restricted stock units recognized in income was $8 million and $13 million , respectively, with the related tax benefit also recognized in income of $4 million and $4 million , respectively. As of December 31, 2017 , $3 million of total unrecognized compensation cost related to restricted stock units will be recognized over a weighted-average period of approximately 12 months. See "Performance Share Unit Awards" herein for additional information.

*Change in Control Awards*

Southern Company awarded performance share units to certain employees remaining with the Company in lieu of certain change in control benefits the employee was entitled to receive following the Merger (change-in-control awards). Shares of Southern Company common stock and/or cash equal to the dollar value of the change-in-control benefit will vest and be issued one-third each year as long as the employee remains in service with the Company, or any of its affiliates, at each vest date. In addition to the change-in-control benefit, Southern Company common stock could be issued to the employees at the end of a performance period with the number of shares issued ranging from 0% to 100% of the target number of performance share units granted, based on achievement of certain Southern Company common stock price metrics, as well as performance goals established by the Compensation Committee of the Southern Company Board of Directors (achievement shares).

The change-in-control benefits are accounted for as a liability award with the fair value equal to the guaranteed dollar value of the change-in-control benefit. The grant-date fair value of the achievement portion of the award was determined using a Monte Carlo simulation model to estimate the number of achievement shares expected to vest based on the Southern Company common stock price. The expected payout is reevaluated annually with expense recognized to date increased or decreased proportionately based on the expected performance. The compensation expense ultimately recognized for the achievement shares will be based on the actual performance.

For the successor year ended December 31, 2017 and the successor period of July 1, 2016 through December 31, 2016 , total compensation cost for the change-in-control awards recognized in income was $12 million and $4 million , respectively, with $6 million and less than $1 million , respectively, of related tax benefit recognized in income. The compensation cost related to the grant of Southern Company change-in-control benefit and achievement shares to the Company's employees are recognized in the Company's financial statements with a corresponding credit to a liability or equity, representing a capital contribution from Southern Company, respectively. As of December 31, 2017 , $8 million of total unrecognized compensation cost related to change in control awards will be recognized over a weighted-average period of approximately 18 months .

**Predecessor**

For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 , the employees of Southern Company Gas and subsidiaries participated in the AGL Resources Inc. Omnibus Performance Incentive Plan, as amended and restated.

The AGL Resources Inc. Omnibus Performance Incentive Plan, as amended and restated, and the Long-Term Incentive Plan (1999) provided for the grant of incentive and nonqualified stock options, stock appreciation rights, shares of restricted stock, restricted stock units, performance cash awards, and other stock-based awards to officers and key employees. Effective July 1, 2016, all Southern Company Gas shares of stock were canceled and/or converted as a result of the Merger. No further grants will be made from the Long-Term Incentive Plan (1999) or the AGL Resources Inc. Omnibus Performance Incentive Plan, as amended and restated.

For the predecessor periods, the Company recognized stock-based compensation expense for its stock-based awards over the requisite service period based on the estimated fair value at the date of grant for its stock-based awards using the modified prospective method. These stock awards included: stock options, stock and restricted stock awards, and performance units (restricted stock units, performance share units, and performance cash units).

Performance-based stock awards and performance units contained market and performance conditions. Stock options, restricted stock awards, and performance units also contained a service condition. The Company estimated forfeitures over the requisite service period when recognizing compensation expense. These estimates were adjusted to the extent that actual forfeitures differ, or were expected to materially differ, from such estimates. Excess tax benefits were reported as a financing cash inflow. The difference between the proceeds from the exercise of the Company's stock-based awards and the par value of the stock was recorded within additional paid-in capital.

Southern Company Gas granted stock awards with a grant price that was equal to the fair market value on the date of the grant. Fair market value was defined under the terms of the applicable plans as the closing price per share of Southern Company Gas' common stock on the grant date. For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 , total compensation cost for cash and stock-based awards recognized in income was $24 million and $40 million , respectively, with related tax benefits also recognized in income, which were immaterial.

### *Incentive and Nonqualified Stock Options*

The stock options that the Company granted prior to the Merger had a three -year vesting period and expired ten years after the date of grant. The exercise price for stock options granted equaled the stock price of Southern Company Gas common stock on the date of grant. Participants realized value from option grants only to the extent that the fair market value of the Company's common stock on the date of exercise of the option exceeded the fair market value of the common stock on the date of the grant. No stock options have been issued under the plan since 2009.

The Company measured compensation cost related to stock options based on the fair value of these awards at their date of grant using the Black-Scholes option-pricing model. For the predecessor year ended December 31, 2015 , the Company had no unrecognized compensation costs related to stock options. For the predecessor period ended June 30, 2016 and the year ended December 31, 2015 , cash received from stock option exercises and the related income tax benefits were immaterial.

For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 , the total intrinsic value of options exercised was $3 million , and $13 million , respectively.

Effective July 1, 2016, all of the Company's outstanding stock options, all of which were fully vested, were canceled and converted into the right to receive an amount in cash equal to the product of (i) the total number of shares of Southern Company Gas' common stock subject to such options and (ii) the excess of the Merger consideration of $66 per share over the applicable exercise price per share of such options.

### *Restricted Stock Units*

A restricted stock unit is an award that represents the opportunity to receive a specified number of shares of the Company's common stock, subject to the achievement of certain pre-established performance criteria. For the predecessor period of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 , the Company granted 25,166 and 47,546 , respectively, of restricted stock units (including dividends) to certain employees. At the effective time of the Merger, all restricted stock units outstanding were deemed fully vested and were canceled and converted into the right to receive an amount in cash equal to the product of (i) the total number of shares of Southern Company Gas' common stock subject to such award and (ii) the Merger consideration of $66 per share.

### *Performance Share Unit Awards*

A performance share unit award represented the opportunity to receive cash and shares subject to the achievement of certain pre-established performance criteria. For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 , the Company granted performance share unit awards to certain officers. The Company's 2016 and 2015 performance share units had two performance measures. One measure, which accounted for 75% , related to the Company's total shareholder return relative to a group of peer companies. The second measure, which accounted for 25% , related to the Company's earnings per share, excluding wholesale gas services, over the three -year performance period.

At the effective time of the Merger, each outstanding performance share unit was converted into an award of Southern Company's restricted stock units. The conversion ratio was the product of (i) the greater of (a) 125% of the number of units underlying such award based on target level achievement of all relevant performance goals and (b) the number of units underlying such award based on the actual level of achievement of all relevant performance goals against target and (ii) an exchange ratio based on the Merger consideration of $66 per share as compared to the volume-weighted average price per share of Southern Company common stock. The resulting Southern Company restricted stock units will follow the vesting schedule and payment terms, and otherwise be issued on similar terms and conditions, as were applicable to such pre-Merger performance share unit awards, subject to certain exceptions. See "Southern Company Restricted Stock Awards" for additional information.

***Stock and Restricted Stock Awards***

The compensation cost of both stock awards and restricted stock awards was equal to the grant date fair value of the awards, recognized over the requisite service period. No other assumptions were used to value the awards. The Company referred to restricted stock as an award of Company common stock subject to time-based vesting or achievement of performance measures. Prior to vesting, restricted stock awards were subject to certain transfer restrictions and forfeiture upon termination of employment.

***Restricted Stock Awards — Employees***

Total unvested restricted stock awards outstanding as of December 31, 2015 totaled 0.4 million . During 2016, 0.3 million restricted stock awards were granted, 0.7 million restricted stock awards were vested or forfeited. At the effective time of the Merger, Southern Company Gas' outstanding restricted stock awards were deemed fully vested and were canceled and converted into the right to receive an amount in cash equal to the product of (i) the total number of shares of Southern Company Gas' common stock subject to such award and (ii) the Merger consideration of $66 per share.

## 9 . FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement. See Note 1 under "Fair Value Measurements" for additional information on the fair value hierarchy.

As of December 31, 2017 , assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| **As of December 31, 2017:** | **Quoted Prices in Active Markets for Identical Assets (Level 1)** | **Significant Other Observable Inputs (Level 2)** | **Significant Unobservable Inputs (Level 3)** | **Net Asset Value as a Practical Expedient (NAV)** | **Total** |
| | | | *(in millions)* | | |
| Assets: | | | | | |
| Energy-related derivatives [(a)(b)] | $ 331 | $ 223 | $ — | $ — | $ 554 |
| Liabilities: | | | | | |
| Energy-related derivatives [(a)(b)] | $ 479 | $ 181 | $ — | $ — | $ 660 |

(a) Energy-related derivatives excludes $11 million associated with premiums and certain weather derivatives accounted for based on intrinsic value rather than fair value.

(b) Energy-related derivatives excludes cash collateral of $193 million .

As of December 31, 2016 , assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| As of December 31, 2016: | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Net Asset Value as a Practical Expedient (NAV) | Total |
| | | | *(in millions)* | | |
| Assets: | | | | | |
| Energy-related derivatives [(a)(b)] | $ 338 | $ 239 | $ — | $ — | $ 577 |
| Liabilities: | | | | | |
| Energy-related derivatives [(a)(b)] | $ 345 | $ 224 | $ — | $ — | $ 569 |

(a) Energy-related derivatives excludes $4 million associated with certain weather derivatives accounted for based on intrinsic value rather than fair value.

(b) Energy-related derivatives excludes cash collateral of $62 million .

**Valuation Methodologies**

The energy-related derivatives primarily consist of exchange-traded financial products for natural gas, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard OTC products that are valued using observable market data and assumptions commonly used by market participants. See Note 10 for additional information on how these derivatives are used.

**Debt**

The Company's long-term debt is recorded at amortized cost, including the fair value adjustments at the effective date of the Merger. The Company amortizes the fair value adjustments over the lives of the respective bonds. The following table presents the carrying amount and fair value of the Company's long-term debt as of December 31:

| | Carrying Amount | Fair Value |
|---|---|---|
| | *(in millions)* | |
| Long-term debt, including securities due within one year: | | |
| **2017** | **$ 6,048** | **$ 6,471** |
| 2016 | $ 5,281 | $ 5,491 |

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates available to the Company.

**10 . DERIVATIVES**

The Company is exposed to market risks, primarily commodity price risk, interest rate risk, and weather risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. Wholesale gas operations use various contracts in its commercial activities that generally meet the definition of derivatives. For other businesses, the Company's policy is that derivatives are to be used primarily for hedging purposes. In both cases, the Company mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a net basis. See Note 9 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

**Energy-Related Derivatives**

The Company enters into energy-related derivatives to hedge exposures to natural gas price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, gas distribution operations has limited exposure to market volatility in prices of natural gas. The Company manages fuel-hedging programs, implemented per the guidelines of the natural gas distribution utilities' respective state regulatory agencies, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility. However, the Company retains exposure to price changes that can, in a volatile energy market, be extremely material and can adversely affect the Company.

The Company also enters into weather derivative contracts as economic hedges of adjusted operating margins in the event of warmer-than-normal weather. Exchange-traded options are carried at fair value, with changes reflected in operating revenues. Non-exchange-traded options are accounted for using the intrinsic value method. Changes in the intrinsic value for non-exchange-traded contracts are reflected in the statements of income.

Energy-related derivative contracts are accounted for under one of three methods:

- *Regulatory Hedges* — Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the natural gas distribution utilities' fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in the cost of natural gas as the underlying natural gas is used in operations and ultimately recovered through the respective cost recovery clauses.
- *Cash Flow Hedges* — Gains and losses on energy-related derivatives designated as cash flow hedges (which are mainly used to hedge anticipated purchases and sales) are initially deferred in other OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* — Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income in the period of change.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the natural gas industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2017 , the net volume of energy-related derivative contracts for natural gas positions totaled 300 million mmBtu for the Company, together with the longest hedge date of 2020 over which the Company is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest non-hedge date of 2026 for derivatives not designated as hedges.

For cash flow hedges, the estimated pre-tax losses that will be reclassified from accumulated OCI to earnings for the 12-month period ending December 31, 2018 are $4 million .

**Interest Rate Derivatives**

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings, with any ineffectiveness recorded directly to earnings. Derivatives related to existing fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains or losses and hedged items' fair value gains or losses are both recorded directly to earnings, providing an offset, with any difference representing ineffectiveness. Fair value gains or losses on derivatives that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

In 2015, the Company executed $800 million in notional value of 10 -year and 30 -year fixed-rate forward-starting interest rate swaps to hedge potential interest rate volatility designated as cash flow hedges of issuances of long-term debt in the fourth quarter 2015 and during 2016. The Company settled $200 million of these interest rate swaps in 2015 for an immaterial loss, $400 million in May 2016 at a loss of $26 million , and the remaining $200 million in September 2016 at a loss of $35 million . Due to the application of acquisition accounting, only $5 million of the pre-tax loss incurred and deferred in the successor period is being amortized to interest expense through 2046.

**Derivative Financial Statement Presentation and Amounts**

The derivative contracts of the Company are subject to master netting arrangements or similar agreements and are reported net in the financial statements. Some of these energy-related and interest rate derivative contracts may contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements.

**NOTES (continued)**
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At December 31, 2017 and 2016 , the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

| | 2017 | | 2016 | |
|---|---|---|---|---|
| **Derivative Category and Balance Sheet Location** | **Assets** | **Liabilities** | **Assets** | **Liabilities** |
| | *(in millions)* | | *(in millions)* | |
| **Derivatives designated as hedging instruments for regulatory purposes** | | | | |
| Energy-related derivatives: | | | | |
| Assets from risk management activities/Liabilities from risk management activities-current | **$ 5** | **$ 8** | $ 24 | $ 3 |
| Other deferred charges and assets/Other deferred credits and liabilities | — | — | 1 | — |
| **Total derivatives designated as hedging instruments for regulatory purposes** | **$ 5** | **$ 8** | $ 25 | $ 3 |
| **Derivatives designated as hedging instruments in cash flow and fair value hedges** | | | | |
| Energy-related derivatives: | | | | |
| Assets from risk management activities/Liabilities from risk management activities-current | **$ —** | **$ 3** | $ 4 | $ 3 |
| **Derivatives not designated as hedging instruments** | | | | |
| Energy-related derivatives: | | | | |
| Assets from risk management activities/Liabilities from risk management activities-current | **$ 379** | **$ 434** | $ 486 | $ 482 |
| Other deferred charges and assets/Other deferred credits and liabilities | **170** | **215** | 66 | 81 |
| **Total derivatives not designated as hedging instruments** | **$ 549** | **$ 649** | $ 552 | $ 563 |
| **Gross amounts recognized** | **$ 554** | **$ 660** | $ 581 | $ 569 |
| **Gross amounts offset** [(a)] | **$ (390)** | **$ (583)** | $ (435) | $ (497) |
| **Net amounts recognized in the Balance Sheets** [(b)] | **$ 164** | **$ 77** | $ 146 | $ 72 |

(a) Gross amounts offset include cash collateral held on deposit in broker margin accounts of $193 million and $62 million as of December 31, 2017 and 2016 , respectively.

(b) Net amount of derivative instruments outstanding excludes premiums and intrinsic value associated with weather derivatives of $11 million as of December 31, 2017 .

At December 31, 2017 and 2016 , the pre-tax effect of unrealized derivative gains (losses) arising from energy-related derivatives designated as regulatory hedging instruments and deferred were as follows:

| | | Unrealized Losses | | | Unrealized Gains | |
|---|---|---|---|---|---|---|
| **Derivative Category** | **Balance Sheet Location** | **2017** | 2016 | **Balance Sheet Location** | **2017** | 2016 |
| | | *(in millions)* | | | *(in millions)* | |
| Energy-related derivatives: | | | | | | |
| | Other regulatory assets, current | **$ (4)** | $ (1) | Other regulatory liabilities, current | **$ 7** | $ 17 |
| | Other regulatory assets, deferred | **—** | — | Other regulatory liabilities, deferred | **—** | 1 |
| **Total energy-related derivative gains (losses)** [(*)] | | **$ (4)** | $ (1) | | **$ 7** | $ 18 |

(*) Fair value gains and losses included in regulatory assets and liabilities include cash collateral held on deposit in broker margin accounts of $6 million as of December 31, 2017 and $8 million as of December 31, 2016 .

For all periods presented, the pre-tax effect of energy-related derivatives and interest rate derivatives designated as cash flow hedging instruments recognized in OCI and those reclassified from accumulated OCI into earnings were as follows:

| | Gain (Loss) Recognized in OCI on Derivative (Effective Portion) | | | Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) |
|---|---|---|---|---|
| | Successor | | | Successor |
| **Derivatives in Cash Flow Hedging Relationships** | **2017** | **Statements of Income Location** | | **2017** |
| | *(in millions)* | | | *(in millions)* |
| Energy-related derivatives | **$ (9)** | Cost of natural gas | | **$ (2)** |

| | Gain (Loss) Recognized in OCI on Derivative (Effective Portion) | | | Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) | |
|---|---|---|---|---|---|
| | Successor | Predecessor | | Successor | Predecessor |
| **Derivatives in Cash Flow Hedging Relationships** | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | **Statements of Income Location** | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 |
| | *(in millions)* | *(in millions)* | | *(in millions)* | *(in millions)* |
| Energy-related derivatives | $ 2 | $ — | Cost of natural gas | $ (1) | $ (1) |
| Interest rate derivatives | (5) | (64) | Interest expense, net of amounts capitalized | — | — |
| **Total derivatives in cash flow hedging relationships** | $ (3) | $ (64) | | $ (1) | $ (1) |

| | Gain (Loss) Recognized in OCI on Derivative (Effective Portion) | | Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) |
|---|---|---|---|
| | Predecessor | | Predecessor |
| **Derivatives in Cash Flow Hedging Relationships** | 2015 | **Statements of Income Location** | 2015 |
| | *(in millions)* | | *(in millions)* |
| Energy-related derivatives | $ 3 | Cost of natural gas | $ (10) |
| | | Other operations and maintenance | (1) |
| Interest rate derivatives | — | Interest expense, net of amounts capitalized | 2 |
| **Total derivatives in cash flow hedging relationships** | $ 3 | | $ (9) |

There was no material ineffectiveness recorded in earnings for any period presented.

For all periods presented, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of income were as follows:

| | | Gain (Loss) | | | |
|---|---|---|---|---|---|
| | | Successor | | Predecessor | |
| **Derivatives in Non-Designated Hedging Relationships** | **Statements of Income Location** | **Year Ended December 31, 2017** | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | Year Ended December 31, 2015 |
| | | *(in millions)* | | *(in millions)* | |
| Energy-related derivatives | Natural gas revenues (*) | **$ (80)** | $ 33 | $ (1) | $ 56 |
| | Cost of natural gas | **(2)** | 3 | (62) | (6) |
| **Total derivatives in non-designated hedging relationships** | | **$ (82)** | $ 36 | $ (63) | $ 50 |

(*) Excludes the impact of weather derivatives recorded in natural gas revenues of $23 million for the successor year ended December 31, 2017 , $6 million for the successor period of July 1, 2016 through December 31, 2016 , $3 million for the predecessor period of January 1, 2016 through June 30, 2016 , and $12 million for the predecessor year ended December 31, 2015 .

**Contingent Features**

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of a credit rating change below BBB- and/or Baa3. At December 31, 2017 , the Company had no collateral posted with derivative counterparties to satisfy these arrangements.

At December 31, 2017 , the fair value of derivative liabilities with contingent features was $3 million and the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, was $2 million .

Generally, collateral may be provided by a guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Prior to entering into a physical transaction, the Company assigns physical wholesale counterparties an internal credit rating and credit limit based on the counterparties' Moody's, S&P, and Fitch ratings, commercially available credit reports, and audited financial statements. The Company may require counterparties to pledge additional collateral when deemed necessary. Credit evaluations are conducted and appropriate internal approvals are obtained for a counterparty's line of credit before any transaction with the counterparty is executed. In most cases, the counterparty must have an investment grade rating, which includes a minimum long-term debt rating of Baa3 from Moody's and BBB- from S&P. Generally, the Company requires credit enhancements by way of a guaranty, cash deposit, or letter of credit for transaction counterparties that do not have investment grade ratings.

The Company also utilizes master netting agreements whenever possible to mitigate exposure to counterparty credit risk. When the Company is engaged in more than one outstanding derivative transaction with the same counterparty and it also has a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of the Company's credit risk. The Company also uses other netting agreements with certain counterparties with whom it conducts significant transactions. Master netting agreements enable the Company to net certain assets and liabilities by counterparty. The Company also nets across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions. The Company may require counterparties to pledge additional collateral when deemed necessary. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

## 11 . MERGER, ACQUISITION, AND DISPOSITIONS

### Merger with Southern Company

On July 1, 2016, the Company completed the Merger with Southern Company. A wholly-owned, direct subsidiary of Southern Company merged with and into Southern Company Gas, with the Company surviving as a wholly-owned, direct subsidiary of Southern Company.

At the effective time of the Merger, each share of Southern Company Gas common stock, other than certain excluded shares, was converted into the right to receive $66 in cash, without interest. Also at the effective time of the Merger, all of the outstanding restricted stock units, restricted stock awards, non-employee director stock awards, stock options, and performance share units were either redeemed or converted into Southern Company's restricted stock units. See Note 8 for additional information.

The application of the acquisition method of accounting was pushed down to the Company. The excess of the purchase price over the fair values of the Company's assets and liabilities was recorded as goodwill, which represents a different basis of accounting from the historical basis prior to the Merger. The following table presents the final purchase price allocation:

| | Successor | Predecessor | |
|---|---|---|---|
| | New Basis | Old Basis | Change in Basis |
| | *(in millions)* | *(in millions)* | |
| Current assets | $ 1,557 | $ 1,474 | $ 83 |
| Property, plant, and equipment | 10,108 | 10,148 | (40) |
| Goodwill | 5,967 | 1,813 | 4,154 |
| Other intangible assets | 400 | 101 | 299 |
| Regulatory assets | 1,118 | 679 | 439 |
| Other assets | 229 | 273 | (44) |
| Current liabilities | (2,201) | (2,205) | 4 |
| Other liabilities | (4,742) | (4,600) | (142) |
| Long-term debt | (4,261) | (3,709) | (552) |
| Contingently redeemable noncontrolling interest | (174) | (41) | (133) |
| Total purchase price/equity | $ 8,001 | $ 3,933 | $ 4,068 |

Measurement period adjustments were recorded to the purchase price allocation during the fourth quarter 2016, which resulted in a net $30 million increase in goodwill to establish intangible liabilities for transportation contracts at wholesale services, partially offset by adjustments to deferred tax balances.

In determining the fair value of assets and liabilities subject to rate regulation that allows recovery of costs and/or a fair return on investments, historical cost was deemed to be a reasonable proxy for fair value, as it is included in rate base or otherwise specified in regulatory recovery mechanisms. Property, plant, and equipment subject to rate regulation was reflected based on the historical gross amount of assets in service and accumulated depreciation, as they are included in rate base. For certain assets and liabilities subject to rate regulation (such as debt instruments and employee benefit obligations), the fair value adjustment was applied to historical cost with a corresponding offset to regulatory asset or liability based on the assessment of probable future recovery in rates.

For unregulated assets and liabilities, fair value adjustments were applied to historical cost of natural gas for sale, property, plant, and equipment, debt instruments, and noncontrolling interest. The valuation of other intangible assets included customer relationships, trade names, and favorable/unfavorable contracts. The valuation of these assets and liabilities applied either the market approach or income approach. The market approach was utilized when prices and other relevant market information were available. The income approach, which is based on discounted cash flows, was primarily based on significant unobservable inputs (Level 3). Key estimates and inputs included forecasted profitability and cash flows, customer retention rates, royalty rates, and discount rates.

The estimated fair value of deferred income taxes was determined by applying the appropriate enacted statutory tax rate to the temporary differences that arose on the differences between the financial reporting value and tax basis of the assets acquired and liabilities assumed.

The excess of the purchase price over the estimated fair value of assets and liabilities of $6 billion was recognized as goodwill, which is primarily attributable to positioning Southern Company to provide natural gas infrastructure to meet customers' growing energy needs and to compete for growth across the energy value chain. The Company anticipates that the majority of the value assigned to goodwill will not be deductible for tax purposes.

The receipt of required regulatory approvals was conditioned upon certain terms and commitments. In connection with these regulatory approvals, certain regulatory agencies prohibited the Company from recovering goodwill and Merger-related expenses, required the Company to maintain a minimum number of employees for a set period of time to ensure that certain pipeline safety standards and the competence level of the employee workforce is not degraded, and/or required the Company to maintain its pre-Merger level of support for various social and charitable programs. The most notable terms and commitments with potential financial impacts included:

- rate credits of $18 million to be paid to customers in New Jersey and Maryland;
- sharing of Merger savings with customers in Georgia starting in 2020;
- phasing-out the use of the Nicor name or logo by certain of the Company's gas marketing services subsidiaries in conducting non-utility business in Illinois;
- reaffirming that Elizabethtown Gas would file a base rate case no later than September 1, 2016, with another base rate case no later than three years after the 2016 rate case; and
- requiring Elkton Gas to file a base rate case within two years of closing the Merger.

There is no restriction on the Company's other utilities' ability to file future rate cases. The rate credits to customers in New Jersey and Maryland were paid during the third and fourth quarters of 2016, respectively. The use of the Nicor name and logo was phased out, effective November 1, 2017, by certain of the Company's gas marketing services subsidiaries in conducting non-utility business in Illinois. Elizabethtown Gas filed a base rate case with the New Jersey BPU on September 1, 2016. See Note 3 under "Base Rate Cases" for additional information. Upon completion of the Merger, the Company amended and restated its Bylaws and Articles of Incorporation, under which it now has the authority to issue no more than 110 million shares of stock consisting of (i) 100 million shares of common stock and (ii) 10 million shares of preferred stock, both categories of which have a par value of $0.01 per share. The amended and restated Articles of Incorporation do not allow any treasury shares to be held.

**Investment in SNG**

In September 2016, the Company, through a wholly-owned, indirect subsidiary, acquired a 50% equity interest in SNG pursuant to a definitive agreement between Southern Company and Kinder Morgan, Inc. in July 2016, to which Southern Company assigned all rights and obligations to the Company in August 2016. SNG owns a 7,000 -mile pipeline system connecting natural gas supply basins in Texas, Louisiana, Mississippi, and Alabama to markets in Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina, and Tennessee. The purchase price of $1.4 billion was financed by a $1.05 billion equity contribution from Southern Company and $360 million of cash paid by the Company, which was financed by a promissory note from Southern Company repaid with a portion of the proceeds from senior notes issued in September 2016. The purchase price of the 50% equity interest exceeded the underlying ownership interest in the net assets of SNG by approximately $700 million . This basis difference is attributable to goodwill and deferred tax assets. While the deferred tax assets will be amortized through deferred tax expense, the goodwill will not be amortized and is not required to be tested for impairment on an annual basis. The Company's investment in SNG decreased by $104 million related to the impact of the Tax Reform Legislation and new income tax apportionment factors in several states resulting from the Company's inclusion in the consolidated Southern Company state tax filings.

On March 31, 2017, the Company made an additional $50 million contribution to maintain its 50% equity interest in SNG. See Note 4 under "Equity Method Investments" for additional information on this investment.

**Proposed Sale of Elizabethtown Gas and Elkton Gas**

On October 15, 2017, the Company's subsidiary, Pivotal Utility Holdings, entered into agreements for the sale of the assets of two of its natural gas distribution utilities, Elizabethtown Gas and Elkton Gas, to South Jersey Industries, Inc. for a total cash purchase price of $1.7 billion . The completion of each asset sale is subject to the satisfaction or waiver of certain conditions, including, among other customary closing conditions, the receipt of required regulatory approvals, including the FERC, the Federal Communications Commission, the New Jersey BPU, and, with respect to the sale of Elkton Gas, the Maryland PSC. The Company and South Jersey Industries, Inc. made joint filings on December 22, 2017 and January 16, 2018 with the New Jersey BPU and the Maryland PSC, respectively, requesting regulatory approval. The asset sales are expected to be completed by the end of the third quarter 2018.

The ultimate outcome of these matters cannot be determined at this time.

## 12 . SEGMENT AND RELATED INFORMATION

The Company manages its business through four reportable segments - gas distribution operations, gas marketing services, wholesale gas services, and gas midstream operations. The non-reportable segments are combined and presented as all other. In conjunction with the Merger, the Company changed the names of certain reportable segments to better align with its new parent company.

Gas distribution operations is the largest component of the Company's business and includes natural gas local distribution utilities that construct, manage, and maintain intrastate natural gas pipelines and gas distribution facilities in seven states. Gas marketing services includes natural gas marketing to end-use customers primarily in Georgia and Illinois. Additionally, gas marketing services provides home equipment protection products and services. Wholesale gas services provides natural gas asset management and/or related logistics services for each of the Company's utilities except Nicor Gas as well as for non-affiliated companies. Additionally, wholesale gas services segment engages in natural gas storage and gas pipeline arbitrage and related activities. Since the acquisition of the Company's 50% interest in SNG, gas midstream operations primarily consists of the Company's gas pipeline investments, with storage and fuel operations also aggregated into this segment. The all other column includes segments below the quantitative threshold for separate disclosure, including the subsidiaries that fall below the quantitative threshold for separate disclosure.

After the Merger, the Company changed the segment performance measure to net income, which is utilized by its parent company. In order to properly assess net income by segment, the Company executed various intercompany note agreements to revise interest charges to its segments. Since such agreements did not exist in the predecessor periods, the Company is unable to provide the comparable net income for those periods.

**NOTES (continued)**
**Southern Company Gas and Subsidiary Companies 2017 Annual Report**

Financial data for business segments for the successor year ended December 31, 2017 , the successor period of July 1, 2016 through December 31, 2016 , and the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 were as follows:

| | Gas Distribution Operations | Gas Marketing Services | Wholesale Gas Services [(a)] | Gas Midstream Operations | Total | All Other | Eliminations | Consolidated |
|---|---|---|---|---|---|---|---|---|
| | | | | *(in millions)* | | | | |
| **Successor – Year ended December 31, 2017** | | | | | | | | |
| **Operating revenues** | **$ 3,207** | **$ 860** | **$ 6** | **$ 71** | **$ 4,144** | **$ 10** | **$ (234)** | **$ 3,920** |
| **Depreciation and amortization** | **391** | **62** | **2** | **18** | **473** | **28** | **—** | **501** |
| **Operating income (loss)** | **650** | **113** | **(51)** | **(10)** | **702** | **(37)** | **—** | **665** |
| **Earnings from equity method investments** | **—** | **—** | **—** | **103** | **103** | **3** | **—** | **106** |
| **Interest expense** | **(153)** | **(5)** | **(7)** | **(33)** | **(198)** | **(2)** | **—** | **(200)** |
| **Income taxes** [(b)] | **178** | **24** | **—** | **61** | **263** | **104** | **—** | **367** |
| **Segment net income (loss)** [(b)] | **353** | **84** | **(57)** | **3** | **383** | **(140)** | **—** | **243** |
| **Gross property additions** | **1,330** | **9** | **1** | **134** | **1,474** | **34** | **—** | **1,508** |
| **Successor – Total assets at December 31, 2017** | **19,358** | **2,147** | **1,096** | **2,241** | **24,842** | **12,184** | **(14,039)** | **22,987** |
| Successor – July 1, 2016 through December 31, 2016 | | | | | | | | |
| Operating revenues | $ 1,342 | $ 354 | $ 24 | $ 31 | $ 1,751 | $ 3 | $ (102) | $ 1,652 |
| Depreciation and amortization | 185 | 35 | 1 | 9 | 230 | 8 | — | 238 |
| Operating income (loss) | 222 | 27 | (2) | (7) | 240 | (43) | — | 197 |
| Earnings from equity method investments | — | — | — | 58 | 58 | 2 | — | 60 |
| Interest expense | (105) | (1) | (3) | (16) | (125) | 44 | — | (81) |
| Income taxes | 51 | 7 | (3) | 16 | 71 | 5 | — | 76 |
| Segment net income (loss) | 77 | 19 | — | 20 | 116 | (2) | — | 114 |
| Gross property additions | 561 | 5 | 1 | 54 | 621 | 11 | — | 632 |
| Successor – Total assets at December 31, 2016 | 19,453 | 2,084 | 1,127 | 2,211 | 24,875 | 11,145 | (14,167) | 21,853 |

**NOTES (continued)**
**Southern Company Gas and Subsidiary Companies 2017 Annual Report**

| | Gas Distribution Operations | Gas Marketing Services | Wholesale Gas Services [(a)] | Gas Midstream Operations | Total | All Other | Eliminations | Consolidated |
|---|---|---|---|---|---|---|---|---|
| | | | | (in millions) | | | | |
| Predecessor – January 1, 2016 through June 30, 2016 | | | | | | | | |
| Operating revenues | $ 1,575 | $ 435 | $ (32) | $ 25 | $ 2,003 | $ 4 | $ (102) | $ 1,905 |
| Depreciation and amortization | 178 | 11 | 1 | 9 | 199 | 7 | — | 206 |
| Operating income (loss) | 351 | 109 | (69) | (9) | 382 | (61) | — | 321 |
| EBIT | 353 | 109 | (68) | (6) | 388 | (60) | — | 328 |
| Gross property additions | 484 | 4 | 1 | 43 | 532 | 16 | — | 548 |
| Predecessor – Year Ended December 31, 2015 | | | | | | | | |
| Operating revenues | $ 3,049 | $ 835 | $ 202 | $ 55 | $ 4,141 | $ 11 | $ (211) | $ 3,941 |
| Depreciation and amortization | 336 | 25 | 1 | 18 | 380 | 17 | — | 397 |
| Operating income (loss) | 571 | 152 | 112 | (26) | 809 | (63) | — | 746 |
| EBIT | 581 | 152 | 110 | (23) | 820 | (59) | — | 761 |
| Gross property additions | 957 | 7 | 2 | 27 | 993 | 34 | — | 1,027 |
| Predecessor – Total assets at December 31, 2015 | 12,519 | 686 | 935 | 692 | 14,832 | 9,662 | (9,740) | 14,754 |

(a) The revenues for wholesale gas services are netted with costs associated with its energy and risk management activities. A reconciliation of operating revenues and intercompany revenues is shown in the following table.

| | Third Party Gross Revenues | Intercompany Revenues | Total Gross Revenues | Less Gross Gas Costs | Operating Revenues |
|---|---|---|---|---|---|
| | | | (in millions) | | |
| **Successor – Year Ended December 31, 2017** | **$ 6,152** | **$ 481** | **$ 6,633** | **$ 6,627** | **$ 6** |
| Su ccessor – July 1, 2016 through December 31, 2016 | 5,807 | 333 | 6,140 | 6,116 | 24 |
| | | | (in millions) | | |
| Predecessor – January 1, 2016 through June 30, 2016 | $ 2,500 | $ 143 | $ 2,643 | $ 2,675 | $ (32) |
| Predecessor – Year Ended December 31, 2015 | 6,286 | 408 | 6,694 | 6,492 | 202 |

(b) Includes the impact of the Tax Reform Legislation and new income tax apportionment factors in several states resulting from the Company's inclusion in the consolidated Southern Company state tax filings.

## 13. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for the successor year ended December 31, 2017 and the successor period of July 1, 2016 through December 31, 2016 and for the predecessor period of January 1, 2016 through June 30, 2016 are as follows:

| Quarter Ended | Operating Revenues | Operating Income (Loss) | EBIT | Net Income (Loss) Attributable to Southern Company Gas |
|---|---|---|---|---|
| | | | *(in millions)* | |
| **Successor - 2017** | | | | |
| **March 2017** | **$ 1,560** | **$ 391** | **$ 435** | **$ 239** |
| **June 2017** | **716** | **96** | **128** | **49** |
| **September 2017** [(a)] | **565** | **68** | **118** | **15** |
| **December 2017** [(a)(b)] | **1,079** | **110** | **129** | **(60)** |
| Predecessor - January 1, 2016 through June 30, 2016 | | | *(in millions)* | |
| March 2016 | $ 1,334 | $ 348 | $ 351 | $ 182 |
| June 2016 | 571 | (27) | (23) | (51) |
| Successor - July 1, 2016 through December 31, 2016 | | | *(in millions)* | |
| September 2016 | $ 543 | $ 12 | $ 50 | $ 4 |
| December 2016 | 1,109 | 185 | 221 | 110 |

(a) Net income (loss) attributable to Southern Company Gas includes the impact of new income tax apportionment factors in several states resulting from the Company's inclusion in the consolidated Southern Company state tax filings.

(b) Net loss attributable to Southern Company Gas includes the impact of the Tax Reform Legislation.

The Company's business is influenced by seasonal weather conditions.

See Note 11 under "Merger with Southern Company" for information on the Merger.

**SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA 2013 - 2017**
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| | Successor | | Predecessor | | | |
|---|---|---|---|---|---|---|
| | **2017** | **July 1, 2016 through December 31, 2016** | **January 1, 2016 through June 30, 2016** | **2015** | **2014** | **2013** |
| **Operating Revenues (in millions)** | **$ 3,920** | $ 1,652 | $ 1,905 | $ 3,941 | $ 5,385 | $ 4,209 |
| **Net Income Attributable to Southern Company Gas (in millions)** | **$ 243** | $ 114 | $ 131 | $ 353 | $ 482 | $ 295 |
| **Cash Dividends on Common Stock (in millions)** | **$ 443** | $ 126 | $ 128 | $ 244 | $ 233 | $ 222 |
| **Return on Average Common Equity (percent)** | **2.68** | 1.74 | 3.31 | 9.05 | 12.96 | 8.42 |
| **Total Assets (in millions)** | **$ 22,987** | $ 21,853 | $ 14,488 | $ 14,754 | $ 14,888 | $ 14,528 |
| **Gross Property Additions (in millions)** | **$ 1,525** | $ 632 | $ 548 | $ 1,027 | $ 769 | $ 731 |
| **Capitalization (in millions):** | | | | | | |
| Common stock equity | **$ 9,022** | $ 9,109 | $ 3,933 | $ 3,975 | $ 3,828 | $ 3,613 |
| Long-term debt | **5,891** | 5,259 | 3,709 | 3,275 | 3,581 | 3,791 |
| Total (excluding amounts due within one year) | **$ 14,913** | $ 14,368 | $ 7,642 | $ 7,250 | $ 7,409 | $ 7,404 |
| **Capitalization Ratios (percent):** | | | | | | |
| Common stock equity | **60.5** | 63.4 | 51.5 | 54.8 | 51.7 | 48.8 |
| Long-term debt | **39.5** | 36.6 | 48.5 | 45.2 | 48.3 | 51.2 |
| Total (excluding amounts due within one year) | **100.0** | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| **Service Contracts (period-end)** | **1,184,257** | 1,198,263 | 1,197,096 | 1,205,476 | 1,162,065 | 1,176,908 |
| **Customers (period-end)** | | | | | | |
| Gas distribution operations | **4,623,249** | 4,586,477 | 4,544,489 | 4,557,729 | 4,529,114 | 4,504,067 |
| Gas marketing services | **773,984** | 655,999 | 630,475 | 654,475 | 633,460 | 632,337 |
| Total (period-end) | **5,397,233** | 5,242,476 | 5,174,964 | 5,212,204 | 5,162,574 | 5,136,404 |
| **Employees (period-end)** | **5,318** | 5,292 | 5,284 | 5,203 | 5,165 | 6,094 |

**SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA 2013 - 2017 (continued)**
**Southern Company Gas and Subsidiary Companies 2017 Annual Report**

| | Successor | | Predecessor | | | |
|---|---|---|---|---|---|---|
| | **2017** | **July 1, 2016 through December 31, 2016** | **January 1, 2016 through June 30, 2016** | **2015** | **2014** | **2013** |
| **Operating Revenues (in millions)** | | | | | | |
| Residential | **$ 2,100** | $ 899 | $ 1,101 | $ 2,129 | $ 2,877 | $ 2,422 |
| Commercial | **641** | 260 | 310 | 617 | 861 | 696 |
| Transportation | **811** | 269 | 290 | 526 | 458 | 487 |
| Industrial | **159** | 74 | 72 | 203 | 242 | 180 |
| Other | **209** | 150 | 132 | 466 | 947 | 424 |
| Total | **$ 3,920** | $ 1,652 | $ 1,905 | $ 3,941 | $ 5,385 | $ 4,209 |
| **Heating Degree Days:** | | | | | | |
| Illinois | **5,246** | 1,903 | 3,340 | 5,433 | 6,556 | 6,305 |
| Georgia | **1,970** | 727 | 1,448 | 2,204 | 2,882 | 2,689 |
| **Gas Sales Volumes (mmBtu in millions):** | | | | | | |
| Gas distributions operations | | | | | | |
| Firm | **667** | 274 | 396 | 695 | 766 | 720 |
| Interruptible | **95** | 47 | 49 | 99 | 106 | 111 |
| Total | **762** | 321 | 445 | 794 | 872 | 831 |
| Gas marketing services | | | | | | |
| Firm: | | | | | | |
| Georgia | **23** | 13 | 21 | 35 | 41 | 38 |
| Illinois | **8** | 4 | 8 | 13 | 17 | 9 |
| Other emerging markets | **15** | 5 | 7 | 11 | 10 | 8 |
| Interruptible (large commercial and industrial) | **11** | 6 | 8 | 14 | 17 | 18 |
| Total | **57** | 28 | 44 | 73 | 85 | 73 |
| Market share in Georgia (percent) | **29.2** | 29.4 | 29.3 | 29.7 | 30.6 | 31.4 |
| Wholesale gas services | | | | | | |
| Daily physical sales ( *mmBtu in millions/day* ) | **6.4** | 7.2 | 7.6 | 6.8 | 6.3 | 5.7 |

# PART III

Items 10 (other than the information under "Code of Ethics" below), 11, 12, 13, and 14 for Southern Company are incorporated by reference to Southern Company's Definitive Proxy Statement relating to the 2018 Annual Meeting of Stockholders. Specifically, reference is made to "Corporate Governance at Southern Company" and "Section 16(a) Beneficial Ownership Reporting Compliance" for Item 10, "Compensation Discussion and Analysis," "Executive Compensation Tables," and "Director Compensation" for Item 11, "Stock Ownership Information," "Executive Compensation Tables," and "Equity Compensation Plan Information" for Item 12, "Southern Company Board" for Item 13, and "Principal Independent Registered Public Accounting Firm Fees" for Item 14.

Items 10 (other than the information under "Code of Ethics" below), 11, 12, 13, and 14 for Alabama Power and Mississippi Power are incorporated by reference to the Definitive Information Statements of Alabama Power and Mississippi Power relating to each of their respective 2018 Annual Meetings of Shareholders. Specifically, reference is made to "Nominees for Election as Directors," "Corporate Governance," and "Section 16(a) Beneficial Ownership Reporting Compliance" for Item 10, "Executive Compensation," "Compensation Committee Interlocks and Insider Participation," "Director Compensation," "Director Deferred Compensation Plan," and "Director Compensation Table" for Item 11, "Stock Ownership Table" and "Executive Compensation" for Item 12, "Certain Relationships and Related Transactions" and "Director Independence" for Item 13, and "Principal Independent Registered Public Accounting Firm Fees" for Item 14.

Items 10, 11, 12, and 13 for each of Georgia Power, Gulf Power, Southern Power, and Southern Company Gas are omitted pursuant to General Instruction I(2)(c) of Form 10-K. Item 14 for each of Georgia Power, Gulf Power, Southern Power, and Southern Company Gas is contained herein.

## ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

***Code of Ethics***

The registrants collectively have adopted a code of business conduct and ethics (Code of Ethics) that applies to each director, officer, and employee of the registrants and their subsidiaries. The Code of Ethics can be found on Southern Company's website located at www.southerncompany.com . The Code of Ethics is also available free of charge in print to any shareholder by requesting a copy from Myra C. Bierria, Corporate Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308. Any amendment to or waiver from the Code of Ethics that applies to executive officers and directors will be posted on the website.

**ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES**

The following represents the fees billed to Georgia Power, Gulf Power, and Southern Power for the last two fiscal years by Deloitte & Touche LLP, each company's principal public accountant for 2017 and 2016 :

| | 2017 | 2016 |
|---|---|---|
| | *(in thousands)* | |
| **Georgia Power** | | |
| Audit Fees (1) | $ 3,247 | $ 3,154 |
| Audit-Related Fees (2) | 96 | 30 |
| Tax Fees | — | — |
| All Other Fees (3) | 1 | 15 |
| Total | $ 3,344 | $ 3,199 |
| **Gulf Power** | | |
| Audit Fees (1) | $ 1,442 | $ 1,346 |
| Audit-Related Fees | 3 | 3 |
| Tax Fees | — | — |
| All Other Fees (3) | — | 2 |
| Total | $ 1,445 | $ 1,351 |
| **Southern Power** | | |
| Audit Fees (1) | $ 1,778 | $ 1,817 |
| Audit-Related Fees | 439 | 372 |
| Tax Fees | — | — |
| All Other Fees (3) | 8 | 6 |
| Total | $ 2,225 | $ 2,195 |

(1) Includes services performed in connection with financing transactions.

(2) Includes both audit and non-statutory audit services in 2017 and non-statutory audit services in 2016.

(3) Represents registration fees for attendance at Deloitte & Touche LLP-sponsored education seminars.

The following represents the fees billed to Southern Company G as for the last two fiscal years by PricewaterhouseCoopers LLP, Southern Company Gas' principal public accountant through February 11, 2016, and Deloitte & Touche LLP, Southern Company Gas' principal public accountant since February 11, 2016:

| | 2017 | 2016 |
|---|---|---|
| | *(in thousands)* | |
| **Southern Company Gas** | | |
| Audit Fees (1) | $ 4,449 | $ 5,131 |
| Audit-Related Fees (2) | 579 | 59 |
| Tax Fees (3) | — | 65 |
| All Other Fees (4) | 8 | 7 |
| Total | $ 5,036 | $ 5,262 |

(1) Includes Deloitte & Touche LLP fees in connection with financing transactions and PricewaterhouseCoopers LLP and Deloitte & Touche LLP fees in connection with audits of several subsidiaries in addition to the consolidated audit.

(2) Represents fees for non-statutory audit services in 2017 and a review report on internal controls provided to third parties billed by Deloitte & Touche LLP in 2017 and 2016.

(3) Represents fees billed by Deloitte & Touche LLP for tax compliance services.

(4) Represents registration fees for attendance at Deloitte & Touche LLP-sponsored education seminars and subscription fees for Deloitte & Touche LLP's technical accounting research tool.

The Southern Company Audit Committee (on behalf of Southern Company and its subsidiaries) adopted a Policy of Engagement of the Independent Auditor for Audit and Non-Audit Services that includes requirements for such Audit Committee to pre-approve audit and non-audit services provided by Deloitte & Touche LLP. All of the audit services provided by Deloitte & Touche LLP in fiscal years 2017 and 2016 (described in the footnotes to the table above) and related fees were approved in advance by the Southern Company Audit Committee.

Prior to the closing of the Merger, the Southern Company Gas Audit Committee had responsibility for appointing, setting compensation, and overseeing the work of Southern Company Gas' independent registered public accounting firm. In recognition of this responsibility, Southern Company Gas' Audit Committee adopted a policy that required specific Audit Committee approval before any services were provided by the independent registered public accounting firm. All of the audit services provided by PricewaterhouseCoopers LLP and Deloitte & Touche LLP in fiscal year 2016 (described in the footnotes to the table above) prior to the closing of the Merger and related fees were approved in advance by the Southern Company Gas Audit Committee.

# PART IV

## Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this report on Form 10-K:

(1) Financial Statements and Financial Statement Schedules:

Management's Report on Internal Control Over Financial Reporting for Southern Company and Subsidiary Companies is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Alabama Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Georgia Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Gulf Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Mississippi Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Southern Power and Subsidiary Companies is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Southern Company Gas and Subsidiary Companies is listed under Item 8 herein.

Reports of Independent Registered Public Accounting Firm on the financial statements and financial statement schedules for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Company Gas and Subsidiary Companies, as well as the Report of Independent Registered Public Accounting Firm on the financial statements of Southern Power and Subsidiary Companies are listed under Item 8 herein.

The financial statements filed as a part of this report for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power and Subsidiary Companies, and Southern Company Gas and Subsidiary Companies are listed under Item 8 herein.

The financial statement schedules for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Company Gas and Subsidiary Companies are listed in the Index to the Financial Statement Schedules at page S-1.

The financial statements of Southern Natural Gas Company, L.L.C. as of December 31, 2017 and 2016 and for the year ended December 31, 2017 and the four months ended December 31, 2016 are provided by Southern Company Gas as separate financial statements of subsidiaries not consolidated pursuant to Rule 3-09 of Regulation S-X, and are incorporated by reference herein from Exhibit 99(g) hereto.

(2) Exhibits:

Exhibits for Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and Southern Company Gas are listed in the Exhibit Index at page E-1.

## Item 16. FORM 10-K SUMMARY

None.

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the stockholders and the Board of Directors of The Southern Company and Subsidiary Companies

**Opinion on the Financial Statement Schedule**

We have audited the consolidated financial statements of Southern Company and Subsidiary Companies (the Company) as of December 31, 2017 and 2016 , and for each of the three years in the period ended December 31, 2017 , and the Company's internal control over financial reporting as of December 31, 2017 , and have issued our report thereon dated February 20, 2018 ; such report is included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedule of the Company (page S-2) listed in the Index at Item 15. This consolidated financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedule, when considered in relation to the financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 20, 2018

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the stockholders and the Board of Directors of Alabama Power Company

**Opinion on the Financial Statement Schedule**

We have audited the financial statements of Alabama Power Company (the Company) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2017 and 2016 , and for each of the three years in the period ended December 31, 2017 , and have issued our report thereon dated February 20, 2018 ; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-3) listed in the Index at Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Birmingham, Alabama
February 20, 2018

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the stockholder and the Board of Directors of Georgia Power Company

**Opinion on the Financial Statement Schedule**

We have audited the financial statements of Georgia Power Company (the Company) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2017 and 2016 , and for each of the three years in the period ended December 31, 2017 , and have issued our report thereon dated February 20, 2018 ; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-4) listed in the Index at Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 20, 2018

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the stockholder and the Board of Directors of Gulf Power Company

**Opinion on the Financial Statement Schedule**

We have audited the financial statements of Gulf Power Company (the Company) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2017 and 2016 , and for each of the three years in the period ended December 31, 2017 , and have issued our report thereon dated February 20, 2018 ; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-5) listed in the Index at Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statement schedule based on our audits. In our opinion, such financial statement schedule, when considered in relation to the financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 20, 2018

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the stockholders and the Board of Directors of Mississippi Power Company

**Opinion on the Financial Statement Schedule**

We have audited the financial statements of Mississippi Power Company (the Company) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2017 and 2016 , and for each of the three years in the period ended December 31, 2017 , and have issued our report thereon dated February 20, 2018 ; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-6) listed in the Index at Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 20, 2018

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the stockholder and the Board of Directors of Southern Company Gas and Subsidiary Companies

**Opinion on the Financial Statement Schedule**

We have audited the consolidated financial statements of Southern Company Gas and Subsidiary Companies (the Company) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2017 and 2016 , and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows, for the year ended December 31, 2017 and the six-month periods ended June 30, 2016 (Predecessor) and December 31, 2016 (Successor), and have issued our report thereon dated February 20, 2018 ; such report is included elsewhere in this Form 10-K. As indicated in that report, we did not audit the financial statements of Southern Natural Gas Company, L.L.C. (SNG), the Company's investment in which is accounted for by the use of the equity method. The Company's consolidated financial statements include its equity investment in SNG of $1,262 million and $1,394 million as of December 31, 2017 and December 31, 2016 , respectively, and its earnings from its equity method investment in SNG of $88 million and $56 million for the year ended December 31, 2017 and the six months ended December 31, 2016, respectively. Those statements were audited by other auditors whose report (which expresses an unqualified opinion on SNG's financial statements and contains an emphasis of matter paragraph concerning the extent of its operations and relationships with affiliated entities) have been furnished to us, and our opinion, insofar as it relates to the amounts included for SNG, is based solely on the report of the other auditors. Our audits also included the consolidated financial statement schedule of the Company (Page S-7) listed in the Index at Item 15. This consolidated financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedule, when considered in relation to the financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 20, 2018

**INDEX TO FINANCIAL STATEMENT SCHEDULES**



Schedules I through V not listed above are omitted as not applicable or not required. A Schedule II for Southern Power Company and Subsidiary Companies is not being provided because there were no reportable items for the three-year period ended December 31, 2017 . Columns omitted from schedules filed have been omitted because the information is not applicable or not required.

**THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES**
**SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS**
**FOR THE YEARS ENDED DECEMBER 31, 2017 , 2016 , AND 2015**
*(Stated in Thousands of Dollars)*

| Description | Balance at Beginning of Period | Additions: Charged to Income | Additions: Charged to Other Accounts | Additions: Acquisitions | Deductions (Note) | Balance at End of Period |
|---|---|---|---|---|---|---|
| Provision for uncollectible accounts | | | | | | |
| 2017 | $ 43,429 | $ 55,770 | $ (248) | $ 30 | $ 54,605 | $ 44,376 |
| 2016 | 13,341 | 39,959 | (1,257) | 40,629 | 49,243 | 43,429 |
| 2015 | 18,253 | 31,074 | — | — | 35,986 | 13,341 |

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

**ALABAMA POWER COMPANY**
**SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS**
**FOR THE YEARS ENDED DECEMBER 31, 2017 , 2016 , AND 2015**
*(Stated in Thousands of Dollars)*

| Description | Balance at Beginning of Period | Additions: Charged to Income | Additions: Charged to Other Accounts | Deductions (Note) | Balance at End of Period |
|---|---|---|---|---|---|
| Provision for uncollectible accounts | | | | | |
| 2017 | $ 10,487 | $ 9,367 | $ — | $ 11,075 | $ 8,779 |
| 2016 | 9,597 | 11,310 | — | 10,420 | 10,487 |
| 2015 | 9,143 | 13,500 | — | 13,046 | 9,597 |

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

**GEORGIA POWER COMPANY**
**SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS**
**FOR THE YEARS ENDED DECEMBER 31, 2017 , 2016 , AND 2015**
*(Stated in Thousands of Dollars)*

| Description | Balance at Beginning of Period | Additions: Charged to Income | Additions: Charged to Other Accounts | Deductions (Note) | Balance at End of Period |
|---|---|---|---|---|---|
| Provision for uncollectible accounts | | | | | |
| 2017 | $ 2,836 | $ 11,250 | $ — | $ 11,474 | $ 2,612 |
| 2016 | 2,147 | 14,476 | — | 13,787 | 2,836 |
| 2015 | 6,076 | 16,862 | — | 20,791 | 2,147 |

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

**GULF POWER COMPANY**
**SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS**
**FOR THE YEARS ENDED DECEMBER 31, 2017 , 2016 , AND 2015**
*(Stated in Thousands of Dollars)*

| Description | Balance at Beginning of Period | Additions: Charged to Income | Additions: Charged to Other Accounts | Deductions (Note) | Balance at End of Period |
|---|---|---|---|---|---|
| Provision for uncollectible accounts | | | | | |
| 2017 | $ 732 | $ 2,859 | $ — | $ 2,846 | $ 745 |
| 2016 | 775 | 2,946 | — | 2,989 | 732 |
| 2015 | 2,087 | 2,041 | — | 3,353 | 775 |

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

**MISSISSIPPI POWER COMPANY**
**SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS**
**FOR THE YEARS ENDED DECEMBER 31, 2017 , 2016 , AND 2015**
*(Stated in Thousands of Dollars)*

| Description | Balance at Beginning of Period | Additions: Charged to Income | Additions: Charged to Other Accounts | Deductions (Note) | Balance at End of Period |
|---|---|---|---|---|---|
| Provision for uncollectible accounts | | | | | |
| 2017 | $ 494 | $ 1,377 | $ — | $ 1,279 | $ 592 |
| 2016 | 287 | 1,295 | — | 1,088 | 494 |
| 2015(*) | 825 | (1,994) | — | (1,456) | 287 |

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

(*) The refund ordered by the Mississippi PSC pursuant to the 2015 Mississippi Supreme Court decision relative to a regulatory liability used by Mississippi Power to record financing costs associated with construction of the Kemper County energy facility involved refunding all billed amounts to all historical customers and included an interest component. The refund of approximately $371 million in 2015 was of sufficient magnitude to resolve most past due amounts beyond 30 days aged receivables, accounting for the negative provision of $(2.0) million where risk of collectibility was offset by applying the refund to past due amounts. It was also of sufficient size to offset amounts previously written off in the 2012-2015 time frame, accounting for the net recoveries of $1.5 million .

**SOUTHERN COMPANY GAS AND SUBSIDIARY COMPANIES**
**SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS**
**FOR THE SUCCESSOR PERIODS OF JULY 1, 2016 THROUGH DECEMBER 31, 2016**
**AND THE YEAR ENDED DECEMBER 31, 2017**
**AND THE PREDECESSOR PERIODS OF JANUARY 1, 2016 THROUGH JUNE 30, 2016**
**AND THE YEAR ENDED DECEMBER 31, 2015**
*(Stated in Thousands of Dollars)*

| | | Additions | | | |
|---|---|---|---|---|---|
| Description | Balance at Beginning of Period | Charged to Income | Charged to Other Accounts | Deductions (Note) | Balance at End of Period |
| **Successor – December 31, 2017** | | | | | |
| Provision for uncollectible accounts | $ 27,316 | $ 28,022 | $ (248) | $ 27,286 | $ 27,804 |
| Income tax valuation | 19,182 | — | — | 7,910 | 11,272 |
| **Successor – December 31, 2016** | | | | | |
| Provision for uncollectible accounts | $ 37,663 | $ 9,500 | $ (1,257) | $ 18,590 | $ 27,316 |
| Income tax valuation | 19,182 | — | — | — | 19,182 |
| **Predecessor – June 30, 2016** | | | | | |
| Provision for uncollectible accounts | $ 29,142 | $ 15,976 | $ 1,608 | $ 9,063 | $ 37,663 |
| Income tax valuation | 19,182 | — | — | — | 19,182 |
| **Predecessor – 2015** | | | | | |
| Provision for uncollectible accounts | $ 35,069 | $ 27,050 | $ 3,017 | $ 35,994 | $ 29,142 |
| Income tax valuation | 19,637 | — | — | 455 | 19,182 |

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

**EXHIBIT INDEX**

The exhibits below with an asterisk (*) preceding the exhibit number are filed herewith. The remaining exhibits have previously been filed with the SEC and are incorporated herein by reference. The exhibits marked with a pound sign (#) are management contracts or compensatory plans or arrangements required to be identified as such by Item 15 of Form 10-K.

**(2) Plan of acquisition, reorganization, arrangement, liquidation or succession**

**Southern Company**

(a) 1 — Agreement and Plan of Merger by and among Southern Company, AMS Corp., and Southern Company Gas, dated August 23, 2015. (Designated in Form 8-K dated August 23, 2015, File No. 1-3526, as Exhibit 2.1.)

**Southern Company Gas**

(g) 1 — Agreement and Plan of Merger by and among Southern Company, AMS Corp., and Southern Company Gas, dated August 23, 2015. See Exhibit 2(a)1 herein.

(g) 2 — Purchase and Sale Agreement, dated as of July 10, 2016, among Kinder Morgan SNG Operator LLC, Southern Natural Gas Company, L.L.C., and Southern Company. (Designated in Form 8-K dated August 31, 2016, File No. 1-14174, as Exhibit 2.1a.)

(g) 3 — Assignment, Assumption and Novation of Purchase and Sale Agreement, dated as of August 31, 2016, between Southern Company and Evergreen Enterprise Holdings LLC. (Designated in Form 8-K dated August 31, 2016, File No. 1-14174, as Exhibit 2.1b.)

**(3) Articles of Incorporation and By-Laws**

**Southern Company**

(a) 1 — Composite Certificate of Incorporation of Southern Company, reflecting all amendments thereto through May 26, 2016. (Designated in Registration No. 33-3546 as Exhibit 4(a), in Certificate of Notification, File No. 70-7341, as Exhibit A, in Certificate of Notification, File No. 70-8181, as Exhibit A, in Form 8-K dated May 26, 2010, File No. 1-3526, as Exhibit 3.1 , and in Form 8-K dated May 25, 2016, File No. 1-3526, as Exhibit 3.1 .)

(a) 2 — By-laws of Southern Company as amended effective May 25, 2016, and as presently in effect. (Designated in Form 8-K dated May 25, 2016, File No. 1-3526, as Exhibit 3.2 .)

**Alabama Power**

(b) 1 — Charter of Alabama Power and amendments thereto through September 7, 2017. (Designated in Registration Nos. 2-59634 as Exhibit 2(b), 2-60209 as Exhibit 2(c), 2-60484 as Exhibit 2(b), 2-70838 as Exhibit 4(a)-2, 2-85987 as Exhibit 4(a)-2, 33-25539 as Exhibit 4(a)-2, 33-43917 as Exhibit 4(a)-2, in Form 8-K dated February 5, 1992, File No. 1-3164, as Exhibit 4(b)-3, in Form 8-K dated July 8, 1992, File No. 1-3164, as Exhibit 4(b)-3, in Form 8-K dated October 27, 1993, File No. 1-3164, as Exhibits 4(a) and 4(b), in Form 8-K dated November 16, 1993, File No. 1-3164, as Exhibit 4(a), in Certificate of Notification, File No. 70-8191, as Exhibit A, in Form 10-K for the year ended December 31, 1997, File No. 1-3164, as Exhibit 3(b)2 , in Form 8-K dated August 10, 1998, File No. 1-3164, as Exhibit 4.4 , in Form 10-K for the year ended December 31, 2000, File No. 1-3164, as Exhibit 3(b)2 , in Form 10-K for the year ended December 31, 2001, File No. 1-3164, as Exhibit 3(b)2 , in Form 8-K dated February 5, 2003, File No. 1-3164, as Exhibit 4.4 , in Form 10-Q for the quarter ended March 31, 2003, File No 1-3164, as Exhibit 3(b)1 , in Form 8-K dated February 5, 2004, File No. 1-3164, as Exhibit 4.4 , in Form 10-Q for the quarter ended March 31, 2006, File No. 1-3164, as Exhibit 3(b)(1) , in Form 8-K dated December 5, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 12, 2007, File No. 1-3164, as Exhibit 4.5 , in Form 8-K dated October 17, 2007, File No. 1-3164, as Exhibit 4.5 , in Form 10-Q for the quarter ended March 31, 2008, File No. 1-3164, as Exhibit 3(b)1 , and in Form 8-K dated September 5, 2017, File No. 1-3164, as Exhibit 4.1 .)

(b) 2 — Amended and Restated By-laws of Alabama Power effective February 10, 2014, and as presently in effect. ( Designated in Form 8-K dated February 10, 2014, File No 1-3164, as Exhibit 3.1. )

**Georgia Power**

| | | | |
|---|---|---|---|
| (c) | 1 | — | Charter of Georgia Power and amendments thereto through October 9, 2007. (Designated in Registration Nos. 2-63392 as Exhibit 2(a)-2, 2-78913 as Exhibits 4(a)-(2) and 4(a)-(3), 2-93039 as Exhibit 4(a)-(2), 2-96810 as Exhibit 4(a)-2, 33-141 as Exhibit 4(a)-(2), 33-1359 as Exhibit 4(a)(2), 33-5405 as Exhibit 4(b)(2), 33-14367 as Exhibits 4(b)-(2) and 4(b)-(3), 33-22504 as Exhibits 4(b)-(2), 4(b)-(3) and 4(b)-(4), in Form 10-K for the year ended December 31, 1991, File No. 1-6468, as Exhibits 4(a)(2) and 4(a)(3), in Registration No. 33-48895 as Exhibits 4(b)-(2) and 4(b)-(3), in Form 8-K dated December 10, 1992, File No. 1-6468 as Exhibit 4(b), in Form 8-K dated June 17, 1993, File No. 1-6468, as Exhibit 4(b), in Form 8-K dated October 20, 1993, File No. 1-6468, as Exhibit 4(b), in Form 10-K for the year ended December 31, 1997, File No. 1-6468, as Exhibit 3(c)2 , in Form 10-K for the year ended December 31, 2000, File No. 1-6468, as Exhibit 3(c)2 , in Form 8-K dated June 27, 2006, File No. 1-6468, as Exhibit 3.1 , and in Form 8-K dated October 3, 2007, File No. 1-6468, as Exhibit 4.5 .) |
| (c) | 2 | — | By-laws of Georgia Power as amended effective November 9, 2016, and as presently in effect. (Designated in Form 8-K dated November 9, 2016, File No. 1-6468, as Exhibit 3.1.) |

**Gulf Power**

| | | | |
|---|---|---|---|
| (d) | 1 | — | Amended and Restated Articles of Incorporation of Gulf Power and amendments thereto through June 17, 2013. (Designated in Form 8-K dated October 27, 2005, File No. 001-31737, as Exhibit 3.1 , in Form 8-K dated November 9, 2005, File No. 001-31737, as Exhibit 4.7 , in Form 8-K dated October 16, 2007, File No. 001-31737, as Exhibit 4.5 , and in Form 8-K dated June 10, 2013, File No. 001-31737, as Exhibit 4.7. ) |
| (d) | 2 | — | By-laws of Gulf Power as amended effective July 1, 2017, and as presently in effect. (Designated in Form 10-Q for the quarter ended March 31, 2017, File No. 001-31737, as Exhibit 3(d).) |

**Mississippi Power**

| | | | |
|---|---|---|---|
| (e) | 1 | — | Articles of Incorporation of Mississippi Power, articles of merger of Mississippi Power Company (a Maine corporation) into Mississippi Power and articles of amendment to the articles of incorporation of Mississippi Power through April 2, 2004. (Designated in Registration No. 2-71540 as Exhibit 4(a)-1, in Form U5S for 1987, File No. 30-222-2, as Exhibit B-10, in Registration No. 33-49320 as Exhibit 4(b)-(1), in Form 8-K dated August 5, 1992, File No. 001-11229, as Exhibits 4(b)-2 and 4(b)-3, in Form 8-K dated August 4, 1993, File No. 001-11229, as Exhibit 4(b)-3, in Form 8-K dated August 18, 1993, File No. 001-11229, as Exhibit 4(b)-3, in Form 10-K for the year ended December 31, 1997, File No. 001-11229, as Exhibit 3(e)2, in Form 10-K for the year ended December 31, 2000, File No. 001-11229, as Exhibit 3(e)2, and in Form 8-K dated March 3, 2004, File No. 001-11229, as Exhibit 4.6 .) |
| (e) | 2 | — | By-laws of Mississippi Power as amended effective July 1, 2017, and as presently in effect. (Designated in Form 10-Q for the quarter ended March 31, 2017, File No. 001-11229, as Exhibit 3(e).) |

**Southern Power**

| | | | |
|---|---|---|---|
| (f) | 1 | — | Certificate of Incorporation of Southern Power Company dated January 8, 2001. (Designated in Registration No. 333-98553 as Exhibit 3.1.) |
| (f) | 2 | — | By-laws of Southern Power Company effective January 8, 2001. (Designated in Registration No. 333-98553 as Exhibit 3.2.) |

**Southern Company Gas**

| | | | |
|---|---|---|---|
| (f) | 1 | — | Amended and Restated Articles of Incorporation of Southern Company Gas dated July 11, 2016. (Designated in Form 8-K dated July 8, 2016, File No. 1-14174, as Exhibit 3.1.) |
| (f) | 2 | — | By-laws of Southern Company Gas effective July 11, 2016. (Designated in Form 8-K dated July 8, 2016, File No. 1-14174, as Exhibit 3.2.) |

**(4) Instruments Describing Rights of Security Holders, Including Indentures**

With respect to each of Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and Southern Company Gas, such registrant has excluded certain instruments with respect to long-term debt that does not exceed 10% of the total assets of such registrant and its subsidiaries. Each such registrant agrees, upon request of the SEC, to furnish copies of any or all such instruments to the SEC.

**Southern Company**

(a) 1 — Senior Note Indenture dated as of January 1, 2007, between Southern Company and Wells Fargo Bank, National Association, as Trustee, and certain indentures supplemental thereto through June 21, 2017. (Designated in Form 8-K dated January 11, 2007, File No. 1-3526, as Exhibit 4.1 , in Form 8-K dated August 21, 2013, File No. 1-3526, as Exhibit 4.2 , in Form 8-K dated August 19, 2014, File No. 1-3526, as Exhibit 4.2(b) , in Form 8-K dated June 9, 2015, File No. 1-3526, as Exhibit 4.2 , in Form 8-K dated May 19, 2016, File No. 1-3526, as Exhibit 4.2(a) , in Form 8-K dated May 19, 2016, File No. 1-3526, as Exhibit 4.2(b) , in Form 8-K dated May 19, 2016, File No. 1-3526, as Exhibit 4.2(c) , in Form 8-K dated May 19, 2016, File No. 1-3526, as Exhibit 4.2(d) , in Form 8-K dated May 19, 2016, File No. 1-3526, as Exhibit 4.2(e) , in Form 8-K dated May 19, 2016, File No. 1-3526, as Exhibit 4.2(f) , in Form 8-K dated May 19, 2016, File No. 1-3526, as Exhibit 4.2(g) , and in Form 10-Q for the quarter ended June 30, 2017, File No. 1-3526, as Exhibit 4(a)2 .)

(a) 2 — Subordinated Note Indenture dated as of October 1, 2015, between The Southern Company and Wells Fargo Bank, National Association, as Trustee, and indentures supplemental thereto through November 22, 2017. (Designated in Form 8-K dated October 1, 2015, File No. 1-3526, as Exhibit 4.3 , in Form 8-K dated October 1, 2015, File No. 1-3526, as Exhibit 4.4 , in Form 8-K dated September 12, 2016, File No. 1-3526, as Exhibit 4.4 , in Form 8-K dated December 5, 2016, File No. 1-3526, as Exhibit 4.4, in Form 10-Q for the quarter ended June 30, 2017, File No. 1-3526 as Exhibit 4(a)1 , and in Form 8-K dated November 17, 2017, File No. 1-3526, as Exhibit 4.4 .)

**Alabama Power**

(b) 1 — Subordinated Note Indenture dated as of January 1, 1997, between Alabama Power and Regions Bank, as Successor Trustee, and certain indentures supplemental thereto through October 2, 2002. (Designated in Form 8-K dated January 9, 1997, File No. 1-3164, as Exhibits 4.1, and in Form 8-K dated September 26, 2002, File No. 3164, as Exhibit 4.9-B .)

(b) 2 — Senior Note Indenture dated as of December 1, 1997, between Alabama Power and Regions Bank, as Successor Trustee, and certain indentures supplemental thereto through November 8, 2017. (Designated in Form 8-K dated December 4, 1997, File No. 1-3164, as Exhibit 4.1 , in Form 8-K dated December 6, 2002, File No. 1-3164, as Exhibit 4.2 , in Form 8-K dated February 11, 2003, File No. 1-3164, as Exhibit 4.2(a) , in Form 8-K dated February 11, 2003, File No. 1-3164, as Exhibit 4.2(b) , in Form 8-K dated March 12, 2003, File No. 1-3164, as Exhibit 4.2 , in Form 8-K dated May 1, 2003, File No. 1-3164, as Exhibit 4.2 , in Form 8-K dated November 14, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 8, 2008, File No. 1-3164, as Exhibit 4.2 , in Form 8-K dated February 26, 2009, File No. 1-3164 as Exhibit 4.2 , in Form 8-K dated September 27, 2010, File No. 1-3164, as Exhibit 4.2 , in Form 8-K dated March 3, 2011, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 18, 2011, File No. 1-3164, as Exhibit 4.2(a) , in Form 8-K dated May 18, 2011, File No. 1-3164, as Exhibit 4.2(b) ,in Form 8-K dated January 10, 2012, File No. 1-3164, as Exhibit 4.2 , in Form 8-K dated October 9, 2012, File No. 1-3164, as Exhibit 4.2 , in Form 8-K dated November 27, 2012, File No. 1-3164, as Exhibit 4.2 , in Form 8-K dated December 3, 2013, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 20, 2014, File No. 1-3164, as Exhibit 4.6, in Form 8-K dated March 5, 2015, File No. 1-3164, as Exhibit 4.6 , in Form 8-K dated April 9, 2015, File No. 1-3164, as Exhibit 4.6(b) , in Form 8-K dated January 8, 2016, File No. 1-3164, as Exhibit 4.6 , in Form 8-K dated February 27, 2017, File No. 1-3164, as Exhibit 4.6 , and in Form 8-K dated November 2, 2017, File No. 1-3164, as Exhibit 4.6 .)

(b) 3 — Amended and Restated Trust Agreement of Alabama Power Capital Trust V dated as of October 1, 2002. (Designated in Form 8-K dated September 26, 2002, File No. 1-3164, as Exhibit 4.12-B.)

(b) 4 — Guarantee Agreement relating to Alabama Power Capital Trust V dated as of October 1, 2002. (Designated in Form 8-K dated September 26, 2002, File No. 1-3164, as Exhibit 4.16-B.)

**Georgia Power**

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| (c) | 1 | — | Senior Note Indenture dated as of January 1, 1998, between Georgia Power and Wells Fargo Bank, National Association, as Successor Trustee, and certain indentures supplemental thereto through August 8, 2017. (Designated in Form 8-K dated January 21, 1998, File No. 1-6468, as Exhibits 4.1 , in Form 8-K dated April 10, 2003, File No. 1-6468, as Exhibit 4.1 , in Form 8-K dated March 6, 2007, File No. 1-6468, as Exhibit 4.2 , in Form 8-K dated May 27, 2008, File No. 1-6468, as Exhibit 4.2 , in Form 8-K dated February 4, 2009, File No. 1-6468, as Exhibit 4.2 , in Form 8-K dated December 8, 2009, File No. 1-6468, as Exhibit 4.2 , in Form 8-K dated May 24, 2010, File No. 1-6468, as Exhibit 4.2 , in Form 8-K dated August 26, 2010, File No. 1-6468, as Exhibit 4.2 , in Form 8-K dated February 29, 2012, File No. 1-6468, as Exhibit 4.2 , in Form 8-K dated May 8, 2012, File No. 1-6468, as Exhibit 4.2(b) , in Form 8-K dated March 12, 2013, File No. 1-6468, as Exhibit 4.2(a) , in Form 8-K dated December 1, 2015, File No. 1-6468, as Exhibit 4.2 , in Form 8-K dated March 2, 2016, File No. 1-6468, as Exhibit 4.2(a) , in Form 8-K dated March 2, 2016, File No. 1-6468, as Exhibit 4.2(b) , in Form 8-K dated February 28, 2017, File No. 1-6468, as Exhibit 4.2(a) , in Form 8-K dated February 28, 2017, File No. 1-6468, as Exhibit 4.2(b) , and in Form 8-K dated August 3, 2017, File No. 1-6468, as Exhibit 4.2 .) |
| (c) | 2 | | Subordinated Note Indenture, dated as of September 1, 2017, between Georgia Power and Wells Fargo Bank, National Association, as Trustee, and First Supplemental Indenture thereto dated as of September 21, 2017. (Designated in Form 8-K dated September 18, 2017, File No. 1-6468, as Exhibit 4.3 , and in Form 8-K dated September 18, 2017, File No. 1-6468, as Exhibit 4.4 .) |
| (c) | 3 | — | Loan Guarantee Agreement between Georgia Power and the DOE dated as of February 20, 2014, Amendment No. 1 thereto dated as of June 4, 2015, Amendment No. 2 thereto dated as of March 9, 2016, Amendment No. 3 thereto dated as of July 27, 2017, and Amendment No. 4 thereto dated as of December 8, 2017. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.1 , in Form 10-Q for the quarter ended June 30, 2015, File No. 1-6468, as Exhibit 10(c)1 , in Form 10-Q for the quarter ended March 31, 2016, File No. 1-6468, as Exhibit 4(c)3 , in Form 8-K dated July 27, 2017, File No. 1-6468, as Exhibit 4.1 , and in Form 8-K dated December 8, 2017, File No. 1-6468, as Exhibit 4.1 .) |
| (c) | 4 | — | Note Purchase Agreement among Georgia Power, the DOE, and the Federal Financing Bank dated as of February 20, 2014. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.2.) |
| (c) | 5 | — | Future Advance Promissory Note dated February 20, 2014 made by Georgia Power to the FFB. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.3.) |
| (c) | 6 | — | Deed to Secure Debt, Security Agreement and Fixture Filing between Georgia Power and PNC Bank, National Association, doing business as Midland Loan Services Inc., a division of PNC Bank, National Association dated as of February 20, 2014. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.4.) |
| (c) | 7 | — | Owners Consent to Assignment and Direct Agreement and Amendment to Plant Alvin W. Vogtle Additional Units Ownership Participation Agreement by and among Georgia Power, OPC, MEAG Power, and Dalton dated as of February 20, 2014. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.5.) |

**Gulf Power**

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| (d) | 1 | — | Senior Note Indenture dated as of January 1, 1998, between Gulf Power and Wells Fargo Bank, National Association, as Successor Trustee, and certain indentures supplemental thereto through May 18, 2017. (Designated in Form 8-K dated June 17, 1998, File No. 0-2429, as Exhibit 4.1 , in Form 8-K dated April 6, 2010, File No. 001-31737, as Exhibit 4.2 , in Form 8-K dated September 9, 2010, File No. 001-31737, as Exhibit 4.2 , in Form 8-K dated May 15, 2012, File No. 001-31737, as Exhibit 4.2 , in Form 8-K dated June 10, 2013, File No. 001-31737, as Exhibit 4.2 , in Form 8-K dated September 16, 2014, File No. 001-31737, as Exhibit 4.2 , and in Form 8-K dated May 15, 2017, File No. 001-31737, as Exhibit 4.2 .) |

**Mississippi Power**

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| (e) | 1 | — | Senior Note Indenture dated as of May 1, 1998, between Mississippi Power and Wells Fargo Bank, National Association, as Successor Trustee, and certain indentures supplemental thereto through March 9, 2012. (Designated in Form 8-K dated May 14, 1998, File No. 001-11229, as Exhibit 4.1 , in Form 8-K dated June 24, 2005, File No. 001-11229, as Exhibit 4.2 , in Form 8-K dated March 3, 2009, File No. 001-11229, as Exhibit 4.2 , in Form 8-K dated October 11, 2011, File No. 001-11229, as Exhibit 4.2(b) , and in Form 8-K dated March 5, 2012, File No. 001-11229, as Exhibit 4.2(b) .) |
| (e) | 2 | — | Term Loan Agreement among Mississippi Power and the lenders identified therein, dated as of March 8, 2016. (Designated in Form 10-Q for the quarter ended March 31, 2016, File |

No. 001-11229, as Exhibit 4(e)1.)

**Southern Power**

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| (f) | 1 | — | Senior Note Indenture dated as of June 1, 2002, between Southern Power Company and Wells Fargo Bank, National Association, as Successor Trustee, and certain indentures supplemental thereto through November 16, 2016. (Designated in Registration No. 333-98553 as Exhibit 4.1 , in Form 8-K dated September 14, 2011, File No. 333-98553, as Exhibit 4.4 , in Form 8-K dated July 10, 2013, File No. 333-98553, as Exhibit 4.4 , in Form 8-K dated May 14, 2015, File No. 333-98553, as Exhibit 4.4(a) , in Form 8-K dated May 14, 2015, File No. 333-98553, as Exhibit 4.4(b) , in Form 8-K dated November 12, 2015, File No. 333-98553, as Exhibit 4.4(a) , in Form 8-K dated June 13, 2016, File No. 001-37803, as Exhibit 4.4(a) , in Form 8-K dated June 13, 2016, File No. 001-37803, as Exhibit 4.4(b) , in Form 10-Q for the quarter ended September 30, 2016, File No. 001-37803, as Exhibit 4(f)1 , in Form 10-Q for the quarter ended September 30, 2016, File No. 001-37803, as Exhibit 4(f)2 , in Form 8-K dated November 10, 2016, File No. 001-37803, as Exhibit 4.4(a) , in Form 8-K dated November 10, 2016, File No. 001-37803, as Exhibit 4.4(b) , and in Form 8-K dated November 10, 2016, File No. 001-37803, as Exhibit 4.4(c) .) |
| * (f) | 2 | — | Seventeenth Supplemental Indenture, dated as of November 20, 2017, to Senior Note Indenture providing for the issuance of the Series 2017A Floating Rate Senior Notes due December 20, 2020. |

**Southern Company Gas**

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| (g) | 1 | — | Indenture dated February 20, 2001 between AGL Capital Corporation, AGL Resources Inc., and The Bank of New York, as Trustee. (Designated in Form S-3, File No. 333-69500, as Exhibit 4.2.) |
| (g) | 2 | — | Southern Company Gas Capital Corporation's 6.00% Senior Note s due 2034, 5.25% Senior Notes due 2019, Form of 3 . 50% Senior Note s due 2021, 5.875% Senior Notes due 2041, Form of Series B Senior Notes due 2018, 4.40% Senior Note s due 2043, 3.875% Senior Note s due 2025, 3.250% Senior Notes due 2026, Form of 2.450% Senior Note due October 1, 2023, Form of 3.950% Senior Note due October 1, 2046, and Form of Series 2017A 4.400% Senior Note due May 30, 2047. (Designated in Form 8-K dated September 22, 2004, File No. 1-14174, as Exhibit 4.1 , in Form 8-K dated August 5, 2009, File No. 1-14174, as Exhibit 4.1 , in Form 8-K dated September 15, 2011, File No. 1-14174, as Exhibit 4.1 , in Form 8-K dated March 16, 2011, File No. 1-14174, as Exhibit 4.1 , in Form 8-K dated August 31, 2011, File No. 1-14174, as Exhibit 4.2 , in Form 8-K dated May 13, 2013, File No. 1-14174, as Exhibit 4.2 , in Form 8-K dated November 13, 2015, File No. 1-14174, as Exhibit 4.2 , in Form 8-K dated May 13, 2016, File No. 1-14174, as Exhibit 4.2 , in Form 8-K dated September 8, 2016, File No. 1-14174, as Exhibit 4.1(a) , in Form 8-K dated September 8, 2016, File No. 1-14174, as Exhibit 4.1(b) , and in Form 8-K dated May 5, 2017, File No. 1-14174, as Exhibit 4.1 , respectively.) |
| (g) | 3 | — | Southern Company Gas' Guarant e e related to the 6.00% Senior Notes due 2034 , Guarantee related to the 5.25% Senior Notes due 2019 , Guarantee related to the 5.875% Senior Notes due 2041, Form of Guarantee related to the 3.50% Senior Notes due 2021, Guarantee relat e d to the 4.40% Senior Notes due 2043, Guarantee related to the 3.875% Senior Notes due 2025, Guarantee related to the 3.250% Senior Notes due 2026, Form of Guarantee related to the 2.450% Senior Notes due October 1, 2023, Form of Guarantee related to the 3.950% Senior Notes due October 1, 2046, and Form of Guarantee related to the Series 2017A 4.400% Senior Notes due May 30, 2047. (Designated in Form 8-K dated September 22, 2004, File No. 1-14174, as Exhibit 4.3 , in Form 8-K dated March 16, 2011, File No. 1-14174, as Exhibit 4.2 , in Form 8-K dated September 15, 2011, File No. 1-14174, as Exhibit 4.2 , in Form 8-K dated May 13, 2013, File No. 1-14174, as Exhibit 4.3 , in Form 8-K dated November 13, 2015, File No. 1-14174, as Exhibit 4.3 , in Form 8-K dated May 13, 2016, File No. 1-14174, as Exhibit 4.3 , in Form 8-K dated September 8, 2016, File No. 1-14174, as Exhibit 4.3(a) , in Form 8-K dated September 8, 2016, File No. 1-14174, as Exhibit 4.3(b) , and in Form 8-K dated May 5, 2017, File No. 1-14174, as Exhibit 4.3 , respectively.) |
| (g) | 4 | — | Indenture dated December 1, 1989 of Atlanta Gas Light Company and First Supplemental Indenture thereto dated March 16, 1992. (Designated in Form S-3, File No. 33-32274, as Exhibit 4(a) and in Form S-3, File No. 33-46419, as Exhibit 4(a).) |

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| | (g) | 5 | — | Indenture of Commonwealth Edison Company to Continental Illinois National Bank and Trust Company of Chicago, Trustee, dated as of January 1, 1954, Indenture of Adoption of Northern Illinois Gas Company to Continental Illinois National Bank and Trust Company of Chicago, Trustee, dated February 9, 1954, and certain indentures supplemental thereto. (Designated in Form 10-K for the year ended December 31, 1995, File No. 1-7296, as Exhibit 4.01 , in Form 10-K for the year ended December 31, 1995, File No. 1-7296, as Exhibit 4.02 , in Registration No. 2-56578 as Exhibits 2.21 and 2.25, in Form 10-Q for the quarter ended June 30, 1996, File No. 1-7296, as Exhibit 4.01 , in Form 10-K for the year ended December 31, 1997, File No. 1-7296, as Exhibit 4.19 , in Form 10-K for the year ended December 31, 2003, File No. 1-7296, as Exhibit 4.09 , in Form 10-K for the year ended December 31, 2003, File No. 1-7296, as Exhibit 4.10 , in Form 10-K for the year ended December 31, 2003, File No. 1-7296, as Exhibit 4.11 , in Form 10-K for the year ended December 31, 2006, File No. 1-7296, as Exhibit 4.11 , in Form 10-Q for the quarter ended September 30, 2008, File No. 1-7296, as Exhibit 4.01 , in Form 10-Q for the quarter ended June 31, 2009, File No. 1-7296, as Exhibit 4.01 , in Form 10-Q for the quarter ended September 30, 2012, File No. 1-7296, as Exhibit 4 , and in Form 10-K for the year ended December 31, 2016, File No. 1-14174, as Exhibit 4(g)6 .) |
| * | (g) | 6 | — | Supplemental Indenture dated July 27, 2017 of Northern Illinois Gas Company to The Bank of New York Mellon Trust Company, N.A., under Indenture dated January 1, 1954. |

**(10) Material Contracts**

**Southern Company**

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| # | (a) | 1 | — | Southern Company 2011 Omnibus Incentive Compensation Plan effective May 25, 2011. (Designated in Form 8-K dated May 25, 2011, File No. 1-3526, as Exhibit 10.1.) |
| # | (a) | 2 | — | Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. (Designated in Form 10-Q for the quarter ended March 31, 2011, File No. 1-3526, as Exhibit 10(a)3 .) |
| # | (a) | 3 | — | Deferred Compensation Plan for Outside Directors of The Southern Company, Amended and Restated effective January 1, 2008 and First Amendment thereto effective April 1, 2015. (Designated in Form 10-K for the year ended December 31, 2007, File No. 1-3526, as Exhibit 10(a)3 and in Form 10-Q for the quarter ended June 30, 2015, File No. 1-3526, as Exhibit 10(a)2 .) |
| # * | (a) | 4 | — | Southern Company Deferred Compensation Plan, Amended and Restated as of January 1, 2018. |
| # | (a) | 5 | — | The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective June 30, 2016 and Amendment No. 1 thereto effective January 1, 2017. (Designated in Form 10-Q for the quarter ended June 30, 2016, File No. 1-3526, as Exhibit 10(a)1 and in Form 10-K for the year ended December 31, 2016, File No. 13536, as Exhibit 10(a)18 .) |
| # | (a) | 6 | — | The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of June 30, 2016 and Amendment No. 1 thereto effective January 1, 2017. (Designated in Form 10-Q for the quarter ended June 30, 2016, File No. 1-3526, as Exhibit 10(a)2 and in Form 10-K for the year ended December 31, 2016, File No. 13536, as Exhibit 10(a)19 .) |
| # | (a) | 7 | — | The Southern Company Change in Control Benefits Protection Plan (an amendment and restatement of The Southern Company Change in Control Benefit Plan Determination Policy), effective December 31, 2008. ( Designated in Form 8-K dated December 31, 2008, File No. 1-3526, as Exhibit 10.1 .) |
| # | (a) | 8 | — | Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Linc, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. (Designated in Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)103 and in Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)16 .) |
| # | (a) | 9 | — | Deferred Stock Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. (Designated in Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)104 and in Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)18 .) |

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| # | (a) | 10 | — | Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. (Designated in Form 10-K for the year ended December 31, 2001, File No. 1-3526, as Exhibit 10(a)92 and in Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)20 .) |
| # | (a) | 11 | — | Southern Company Senior Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008, First Amendment thereto effective October 19, 2009, and Second Amendment thereto effective February 22, 2011. (Designated in Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)23 , in Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)22 , and in Form 10-K for the year ended December 31, 2010, File No. 1-3526, as Exhibit 10(a)16 .) |
| # | (a) | 12 | — | Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. (Designated in Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)24 and in Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)24 .) |
| # | (a) | 13 | — | Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. (Designated in Form 10-Q for the quarter ended March 31, 2017, File No. 1-3526, as Exhibit 10(a)1 ). |
| # | (a) | 14 | — | Outside Directors Stock Plan for The Southern Company and its Subsidiaries effective June 1, 2015. (Designated in Definitive Proxy Statement filed April 10, 2015, File No. 1-3526, as Appendix A .) |
| # | (a) | 15 | — | Deferred Compensation Agreement between Southern Company, SCS, Alabama Power, and Mark A. Crosswhite, effective July 30, 2008. (Designated in Form 10-K for the year ended December 31, 2016, File No. 1-3526, as Exhibit 10(a)17 .) |
| # * | (a) | 16 | — | Second Amendment to The Southern Company Supplemental Executive Retirement Plan effective January 1, 2018. |
| # * | (a) | 17 | — | Second Amendment to The Southern Company Supplemental Benefit Plan effective January 1, 2018. |
| | (a) | 18 | — | The Southern Company Employee Savings Plan, Amended and Restated effective January 1, 2018. (Designated in Post-Effective Amendment No. 1 to Form S-8, File No. 333-212783 as Exhibit 4.3 .) |
| # | (a) | 19 | — | Form of Terms for Restricted Stock Unit with Performance Measure Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. (Designated in Form 10-Q for the quarter ended March 31, 2017, File No. 1-3526, as Exhibit 10(a)2 .) |
| # | (a) | 20 | — | Letter Agreement among Southern Company Gas, Southern Company, and Andrew W. Evans and Performance Stock Unit Award Agreement, dated September 29, 2016. (Designated in Form 10-Q for the quarter ended March 31, 2017, File No. 1-3526, as Exhibit 10(a)3 .) |
| # | (a) | 21 | — | Form of Time-Vesting Restricted Stock Unit Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. (Designated in Form 10-Q for the quarter ended March 31, 2017, File No. 1-3526, as Exhibit 10(a)4 .) |
| **Alabama Power** | | | | |
| | (b) | 1 | — | Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. (Designated in Form 10-Q for the quarter ended March 31, 2007, File No. 1-3164, as Exhibit 10(b)5 .) |
| # | (b) | 2 | — | Southern Company 2011 Omnibus Incentive Compensation Plan effective May 25, 2011. See Exhibit 10(a)1 herein. |
| # | (b) | 3 | — | Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein. |
| # | (b) | 4 | — | Southern Company Deferred Compensation Plan, Amended and Restated as of January 1, 2018. See Exhibit 10(a)4 herein. |
| # | (b) | 5 | — | The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective June 30, 2016 and Amendment No. 1 thereto effective January 1, 2017. See Exhibit 10(a)5 herein. |

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| # | (b) | 6 | — | The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of June 30, 2016 and Amendment No. 1 thereto effective January 1, 2017. See Exhibit 10(a)6 herein. |
| # | (b) | 7 | — | Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)12 herein. |
| # | (b) | 8 | — | Deferred Compensation Plan for Outside Directors of Alabama Power Company, Amended and Restated effective January 1, 2008 and First Amendment thereto effective June 1, 2015. (Designated in Form 10-Q for the quarter ended June 30, 2008, File No. 1-3164, as Exhibit 10(b)1 and in Form 10-Q for the quarter ended June 30, 2015, File No. 1-3164, as Exhibit 10(b)1 .) |
| # | (b) | 9 | — | The Southern Company Change in Control Benefits Protection Plan (an amendment and restatement of The Southern Company Change in Control Benefit Plan Determination Policy), effective December 31, 2008. See Exhibit 10(a)7 herein. |
| # | (b) | 10 | — | Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Linc, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)8 herein. |
| # | (b) | 11 | — | Deferred Stock Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)9 herein. |
| # | (b) | 12 | — | Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)10 herein. |
| # | (b) | 13 | — | Southern Company Senior Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008, First Amendment thereto effective October 19, 2009, and Second Amendment thereto effective February 22, 2011. See Exhibit 10(a)11 herein. |
| # | (b) | 14 | — | Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)13 herein. |
| # | (b) | 15 | — | Deferred Compensation Agreement between Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and SCS and Philip C. Raymond dated September 15, 2010. (Designated in Form 10-Q for the quarter ended September 30, 2010, File No. 1-3164, as Exhibit 10(b)2 .) |
| # | (b) | 16 | — | Deferred Compensation Agreement between Southern Company, SCS, Alabama Power, and Mark A. Crosswhite, effective July 30, 2008. See Exhibit 10(a)15 herein. |
| # | (b) | 17 | — | Outside Directors Stock Plan for The Southern Company and its Subsidiaries effective June 1, 2015. See Exhibit 10(a)14 herein. |
| # | (b) | 18 | — | Second Amendment to The Southern Company Supplemental Executive Retirement Plan effective January 1, 2018. See Exhibit 10(a)16 herein. |
| # | (b) | 19 | — | Second Amendment to The Southern Company Supplemental Benefit Plan effective January 1, 2018. See Exhibit 10(a)17 herein. |
| # | (b) | 20 | — | Form of Terms for Restricted Stock Unit with Performance Measure Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)19 herein. |
| # | (b) | 21 | — | Form of Time-Vesting Restricted Stock Unit Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)21 herein. |

**Georgia Power**

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| | (c) | 1 | — | Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. See Exhibit 10(b)1 herein. |
| | (c) | 2 | — | Revised and Restated Integrated Transmission System Agreement dated as of November 12, 1990, between Georgia Power and OPC. (Designated in Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(g).) |

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| (c) | 3 | — | Revised and Restated Integrated Transmission System Agreement between Georgia Power and Dalton dated as of December 7, 1990. (Designated in Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(gg).) |
| (c) | 4 | — | Revised and Restated Integrated Transmission System Agreement between Georgia Power and MEAG Power dated as of December 7, 1990. (Designated in Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(hh).) |
| (c) | 5 | — | Interim Assessment Agreement dated as of March 29, 2017, by and among Georgia Power, for itself and as agent for Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and The City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, and Westinghouse Electric Company LLC, WECTEC Staffing Services LLC, and WECTEC Global Project Services, Inc., Amendment 1 thereto dated as of April 28, 2017, Amendment 2 thereto dated as of May 12, 2017, Amendment 3 thereto dated as of June 3, 2017, Amendment 4 thereto dated as of June 5, 2017, Amendment 5 thereto dated as of March 29, 2017, Amendment 6 thereto dated as of June 22, 2017, Amendment 7 thereto dated as of June 28, 2017 and Amendment 8 thereto dated as of July 20, 2017. (Designated in Form 10-Q for the quarter ended March 31, 2017, File No. 1-6468, as Exhibit 10(c)3 , in Form 10-Q for the quarter ended March 31, 2017, File No. 1-6468, as Exhibit 10(c)4 , in Form 8-K dated May 12, 2017, File No. 1-6468, as Exhibit 10.1 , in Form 8-K dated June 3, 2017, File No. 1-6468, as Exhibit 10.1 , in Form 8-K dated June 5, 2017, File No. 1-6468, as Exhibit 10.1 , in Form 8-K dated June 16, 2017, File No. 1-6468, as Exhibit 10.2 , in Form 8-K dated June 22, 2017, File No. 1-6468, as Exhibit 10.1 , in Form 8-K dated June 28, 2017, File No. 1-6468, as Exhibit 10.1 , and in Form 8-K dated July 20, 2017, File No. 1-6468, as Exhibit 10.1 .) |
| (c) | 6 | — | Settlement Agreement dated as of June 9, 2017, by and among Georgia Power, Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, The City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, and Toshiba Corporation and Amendment No. 1 thereto dated as of December 8, 2017. (Designated in Form 8-K dated June 16, 2017, File No. 1-6468, as Exhibit 10.1 and in Form 8-K dated December 8, 2017, File No. 1-6468, as Exhibit 10.1 .) |
| (c) | 7 | — | Amended and Restated Services Agreement dated as of June 20, 2017, by and among Georgia Power, for itself and as agent for Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and The City of Dalton, acting by and through its Board of Water, Light and Sinking Fund Commissioners, and Westinghouse Electric Company LLC and WECTEC Global Project Services, Inc. (Georgia Power requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Georgia Power omitted such portions from the filing and filed them separately with the SEC.) (Designated in Form 10-Q for the quarter ended June 30, 2017, File No. 1-6468, as Exhibit 10(c)9 .) |
| * (c) | 8 | — | Construction Completion Agreement dated as of October 23, 2017, between Georgia Power, for itself and as agent for Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and The City of Dalton, acting by and through its Board of Water, Light and Sinking Fund Commissioners, and Bechtel Power Corporation. (Georgia Power has requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Georgia Power omitted such portions from the filing and filed them separately with the SEC.) |
| (c) | 9 | — | Plant Alvin W. Vogtle Additional Units Ownership Participation Agreement dated as of April 21, 2006, among Georgia Power, Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and The City of Dalton, Georgia, Amendment 1 thereto dated as of April 8, 2008, Amendment 2 thereto dated as of February 20, 2014, and Agreement Regarding Additional Participating Party Rights and Amendment 3 thereto dated as of November 2, 2017. (Designated in Form 8-K dated April 21, 2006, File No. 33-7591, as Exhibit 10.4.4 , in Form 10-K for the year ended December 31, 2013, File No. 000-53908, as Exhibit 10.3.2(a) , in Form 10-K for the year ended December 31, 2013, File No. 000-53908, as Exhibit 10.3.2(b) , and in Form 10-Q for the quarter ended September 30, 2017, File No. 000-53908, as Exhibit 10.1 .) |

**Gulf Power**

| | | | |
|---|---|---|---|
| (d) | 1 | — | Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. See Exhibit 10(b)1 herein. |

**Mississippi Power**

| | | | |
|---|---|---|---|
| (e) | 1 | — | Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama |

Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS.
See Exhibit 10(b)1 herein.

| | | | | |
|---|---|---|---|---|
| | (e) | 2 | — | Transmission Facilities Agreement dated February 25, 1982, Amendment No. 1 dated May 12, 1982 and Amendment No. 2 dated December 6, 1983, between Entergy Corporation (formerly Gulf States) and Mississippi Power. (Designated in Form 10-K for the year ended December 31, 1981, File No. 001-11229, as Exhibit 10(f), in Form 10-K for the year ended December 31, 1982, File No. 001-11229, as Exhibit 10(f)(2), and in Form 10-K for the year ended December 31, 1983, File No. 001-11229, as Exhibit 10(f)(3).) |
| # | (e) | 3 | — | Southern Company 2011 Omnibus Incentive Compensation Plan effective May 25, 2011. See Exhibit 10(a)1 herein. |
| # | (e) | 4 | — | Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein. |
| # | (e) | 5 | — | Southern Company Deferred Compensation Plan, Amended and Restated as of January 1, 2018. See Exhibit 10(a)4 herein. |
| # | (e) | 6 | — | The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of June 30, 2016 and Amendment No. 1 thereto effective January 1, 2017. See Exhibit 10(a)6 herein. |
| # | (e) | 7 | — | Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)12 herein. |
| # | (e) | 8 | — | The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective June 30, 2016 and Amendment No. 1 thereto effective January 1, 2017. See Exhibit 10(a)5 herein. |
| # | (e) | 9 | — | Deferred Compensation Plan for Outside Directors of Mississippi Power Company, Amended and Restated effective January 1, 2008 and First Amendment thereto effective April 1, 2015. (Designated in Form 10-Q for the quarter ended March 31, 2008, File No. 001-11229 as Exhibit 10(e)1 and in Form 10-Q for the quarter ended June 30, 2015, File No. 001-11229 as Exhibit 10(e)1 .) |
| # | (e) | 10 | — | The Southern Company Change in Control Benefits Protection Plan (an amendment and restatement of The Southern Company Change in Control Benefit Plan Determination Policy), effective December 31, 2008. See Exhibit 10(a)7 herein. |
| # | (e) | 11 | — | Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Linc, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)8 herein. |
| # | (e) | 12 | — | Deferred Stock Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)9 herein. |
| # | (e) | 13 | — | Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)10 herein. |
| # | (e) | 14 | — | Southern Company Senior Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008, First Amendment thereto effective October 19, 2009, and Second Amendment thereto effective February 22, 2011. See Exhibit 10(a)11 herein. |
| | (e) | 15 | — | Cooperative Agreement between the DOE and SCS dated as of December 12, 2008. (Designated in Form 10-K for the year ended December 31, 2008, File No. 001-11229, as Exhibit 10(e)22 .) (Mississippi Power requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Mississippi Power omitted such portions from this filing and filed them separately with the SEC.) |
| # | (e) | 16 | — | Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)13 herein. |
| # | (e) | 17 | — | Outside Directors Stock Plan for The Southern Company and its Subsidiaries effective June 1, 2015. See Exhibit 10(a)14 herein. |
| # | (e) | 18 | — | Letter Agreement between Mississippi Power and Emile J. Troxclair III dated December 11, 2014. (Designated in Form 10-Q for the quarter ended March 31, 2016, File No. 001-11229, as Exhibit 10(e)1 .) |

| | | | | |
|---|---|---|---|---|
| # | (e) | 19 | — | Performance Award Agreement between Southern Company Services, Inc. and Emile J. Troxclair III effective as of January 3, 2015. (Designated in Form 10-Q for the quarter ended March 31, 2016, File No. 001-11229, as Exhibit 10(e)2 .) |
| # | (e) | 20 | — | Second Amendment to The Southern Company Supplemental Executive Retirement Plan effective January 1, 2018. See Exhibit 10(a)16 herein. |
| # | (e) | 21 | — | Second Amendment to The Southern Company Supplemental Benefit Plan effective January 1, 2018. See Exhibit 10(a)17 herein. |
| # | (e) | 22 | — | Form of Terms for Restricted Stock Unit with Performance Measure Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)19 herein. |
| # | (e) | 23 | — | Form of Time-Vesting Restricted Stock Unit Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)21 herein. |

**Southern Power**

| | | | |
|---|---|---|---|
| (f) | 1 | — | Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. See Exhibit 10(b)1 herein. |

**Southern Company Gas**

| | | | |
|---|---|---|---|
| (g) | 1 | — | Note Purchase Agreement dated August 31, 2011. (Designated in Form 8-K dated August 31, 2011, File No. 1-14174, as Exhibit 10.1 .) |
| (g) | 3 | — | Final Allocation Agreement dated January 3, 2008. (Designated in Form 10-K for the year ended December 31, 2007, File No. 1-7296, as Exhibit 10.15 .) |
| (g) | 4 | — | Bank Rate Mode Covenants Agreement, dated as of February 26, 2013 and First Amendment to Bank Rate Mode Covenants Agreement dated as of October 30, 2015. (Designated in Form 8-K dated February 26, 2013, File No. 1-14174, as Exhibit 10.1 and in Form 8-K dated October 30, 2015, File No. 1-14174, as Exhibit 10.3 .) |
| (g) | 5 | — | Loan Agreement dated as of February 1, 2013. (Designated in Form 8-K dated February 26, 2013, File No. 1-14174, as Exhibit 10.2 .) |
| (g) | 6 | — | Loan Agreement dated as of March 1, 2013. (Designated in Form 8-K dated March 25, 2013, File No. 1-14174, as Exhibit 10.1 .) |
| (g) | 7 | — | Amended and Restated Loan Agreement dated as of March 1, 2013. (Designated in Form 8-K dated March 25, 2013, File No. 1-14174, as Exhibit 10.2 .) |
| (g) | 8 | — | Amended and Restated Loan Agreement dated as of March 1, 2013. (Designated in Form 8-K dated March 25, 2013, File No. 1-14174, as Exhibit 10.3 .) |
| (g) | 9 | — | Amended and Restated Loan Agreement dated as of March 1, 2013. (Designated in Form 8-K dated March 25, 2013, File No. 1-14174, as Exhibit 10.4 .) |
| (g) | 10 | — | Asset Purchase Agreement, dated as of October 15, 2017, by and between Pivotal Utility Holdings, Inc., as Seller, and South Jersey Industries, Inc., as Buyer. (Designated in Form 8-K dated October 15, 2017, File No. 1-14174, as Exhibit 10.1 .) |

**(14) Code of Ethics**

**Southern Company**

(a) — The Southern Company Code of Ethics. (Designated in Form 10-K for the year ended December 31, 2016, File No. 1-3526, as Exhibit 14(a).)

**Alabama Power**

(b) — The Southern Company Code of Ethics. See Exhibit 14(a) herein.

**Georgia Power**

(c) — The Southern Company Code of Ethics. See Exhibit 14(a) herein.

**Gulf Power**

(d) — The Southern Company Code of Ethics. See Exhibit 14(a) herein.

**Mississippi Power**

(e) — The Southern Company Code of Ethics. See Exhibit 14(a) herein.

**Southern Power**

(f) — The Southern Company Code of Ethics. See Exhibit 14(a) herein.

**Southern Company Gas**

(g) — The Southern Company Code of Ethics. See Exhibit 14(a) herein.

**(21) Subsidiaries of Registrants**

**Southern Company**

* (a) — Subsidiaries of Registrant.

**Alabama Power**

(b) — Subsidiaries of Registrant. See Exhibit 21(a) herein.

**Georgia Power**

Omitted pursuant to General Instruction I(2)(b) of Form 10-K.

**Gulf Power**

Omitted pursuant to General Instruction I(2)(b) of Form 10-K.

**Mississippi Power**

(e) — Subsidiaries of Registrant. See Exhibit 21(a) herein.

**Southern Power**

Omitted pursuant to General Instruction I(2)(b) of Form 10-K.

**Southern Company Gas**

Omitted pursuant to General Instruction I(2)(b) of Form 10-K

**(23) Consents of Experts and Counsel**

**Southern Company**

* (a) 1 — Consent of Deloitte & Touche LLP.

**Alabama Power**

* (b) 1 — Consent of Deloitte & Touche LLP.

**Georgia Power**

* (c) 1 — Consent of Deloitte & Touche LLP.

**Gulf Power**

* (d) 1 — Consent of Deloitte & Touche LLP.

**Mississippi Power**

* (e) 1 — Consent of Deloitte & Touche LLP.

**Southern Power**

* (f) 1 — Consent of Deloitte & Touche LLP.

**Southern Company Gas**

* (g) 1 — Consent of Deloitte & Touche LLP.
* (g) 2 — Consent of PricewaterhouseCoopers LLP.
* (g) 3 — Consent of PricewaterhouseCoopers LLP.

**(24) Powers of Attorney and Resolutions**

**Southern Company**

* (a) — Power of Attorney and resolution.

**Alabama Power**

* (b) — Power of Attorney and resolution.

**Georgia Power**

* (c) — Power of Attorney and resolution.

**Gulf Power**

| | | | |
|---|---|---|---|
| * (d) | | — | Power of Attorney and resolution. |

**Mississippi Power**

| | | | |
|---|---|---|---|
| *(e) | | — | Power of Attorney and resolution. |

**Southern Power**

| | | | |
|---|---|---|---|
| *(f) | | — | Power of Attorney and resolution. |

**Southern Company Gas**

| | | | |
|---|---|---|---|
| * (g) | | — | Power of Attorney and resolution. |

**(31) Section 302 Certifications**

**Southern Company**

| | | | |
|---|---|---|---|
| * (a) | 1 | — | Certificate of Southern Company's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002. |
| * (a) | 2 | — | Certificate of Southern Company's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002. |

**Alabama Power**

| | | | |
|---|---|---|---|
| * (b) | 1 | — | Certificate of Alabama Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002. |
| * (b) | 2 | — | Certificate of Alabama Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002. |

**Georgia Power**

| | | | |
|---|---|---|---|
| * (c) | 1 | — | Certificate of Georgia Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002. |
| * (c) | 2 | — | Certificate of Georgia Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002. |

**Gulf Power**

| | | | |
|---|---|---|---|
| * (d) | 1 | — | Certificate of Gulf Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002. |
| * (d) | 2 | — | Certificate of Gulf Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002. |

**Mississippi Power**

| | | | |
|---|---|---|---|
| * (e) | 1 | — | Certificate of Mississippi Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002. |
| * (e) | 2 | — | Certificate of Mississippi Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002. |

**Southern Power**

| | | | |
|---|---|---|---|
| * (f) | 1 | — | Certificate of Southern Power Company's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002. |
| * (f) | 2 | — | Certificate of Southern Power Company's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002. |

**Southern Company Gas**

| | | | |
|---|---|---|---|
| * (g) | 1 | — | Certificate of Southern Company Gas' Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002. |
| * (g) | 2 | — | Certificate of Southern Company Gas' Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002. |

**(32) Section 906 Certifications**

**Southern Company**

| | | | |
|---|---|---|---|
| * (a) | | — | Certificate of Southern Company's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002. |

**Alabama Power**

| | | | |
|---|---|---|---|
| * (b) | | — | Certificate of Alabama Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002. |

**Georgia Power**

| | | |
|---|---|---|
| * (c) | — | Certificate of Georgia Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002. |

**Gulf Power**

| | | |
|---|---|---|
| * (d) | — | Certificate of Gulf Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002. |

**Mississippi Power**

| | | |
|---|---|---|
| * (e) | — | Certificate of Mississippi Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002. |

**Southern Power**

| | | |
|---|---|---|
| * (f) | — | Certificate of Southern Power Company's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002. |

**Southern Company Gas**

| | | |
|---|---|---|
| * (g) | — | Certificate of Southern Company Gas' Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002. |

**(99) Additional Exhibits**

**Southern Company Gas**

| | | |
|---|---|---|
| * (g) | — | The financial statements of Southern Natural Gas Company, L.L.C., pursuant to Rule 3-09 of Regulation S-X. |

**(101) XBRL-Related Documents**

| | | |
|---|---|---|
| * INS | — | XBRL Instance Document |
| * SCH | — | XBRL Taxonomy Extension Schema Document |
| * CAL | — | XBRL Taxonomy Calculation Linkbase Document |
| * DEF | — | XBRL Definition Linkbase Document |
| * LAB | — | XBRL Taxonomy Label Linkbase Document |
| * PRE | — | XBRL Taxonomy Presentation Linkbase Document |

**THE SOUTHERN COMPANY**

**SIGNATURES**

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

*THE SOUTHERN COMPANY*

*By:* *Thomas A. Fanning*
*Chairman, President, and*
*Chief Executive Officer*

*By:* */s/Melissa K. Caen*
*(Melissa K. Caen, Attorney-in-fact)*

*Date:* *February 20, 2018*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

*Thomas A. Fanning*
*Chairman, President, and*
*Chief Executive Officer*
*(Principal Executive Officer)*

*Art P. Beattie*
*Executive Vice President and Chief Financial Officer*
*(Principal Financial Officer)*

*Ann P. Daiss*
*Comptroller and Chief Accounting Officer*
*(Principal Accounting Officer)*

*Directors:*

| | |
|---|---|
| *Juanita Powell Baranco* | *Donald M. James* |
| *Jon A. Boscia* | *John D. Johns* |
| *Henry A. Clark III* | *Dale E. Klein* |
| *David J. Grain* | *William G. Smith, Jr.* |
| *Veronica M. Hagen* | *Steven R. Specker* |
| *Warren A. Hood, Jr.* | *Larry D. Thompson* |
| *Linda P. Hudson* | *E. Jenner Wood III* |

*By:* */s/Melissa K. Caen*
*(Melissa K. Caen, Attorney-in-fact)*

*Date: February 20, 2018*

**ALABAMA POWER COMPANY**

**SIGNATURES**

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

*ALABAMA POWER COMPANY*

*By:* *Mark A. Crosswhite*
*Chairman, President, and Chief Executive Officer*

*By:* */s/Melissa K. Caen*
*(Melissa K. Caen, Attorney-in-fact)*

*Date:* *February 20, 2018*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

*Mark A. Crosswhite*
*Chairman, President, and Chief Executive Officer*
*(Principal Executive Officer)*

*Philip C. Raymond*
*Executive Vice President, Chief Financial Officer, and Treasurer*
*(Principal Financial Officer)*

*Anita Allcorn-Walker*
*Vice President and Comptroller*
*(Principal Accounting Officer)*

*Directors:*

*Whit Armstrong*
*David J. Cooper, Sr.*
*O. B. Grayson Hall, Jr.*
*Anthony A. Joseph*
*Patricia M. King*
*James K. Lowder*
*Robert D. Powers*
*Catherine J. Randall*
*C. Dowd Ritter*
*R. Mitchell Shackleford, III*

*By:* */s/Melissa K. Caen*
*(Melissa K. Caen, Attorney-in-fact)*

*Date: February 20, 2018*

**GEORGIA POWER COMPANY**

**SIGNATURES**

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

*GEORGIA POWER COMPANY*

*By:* *W. Paul Bowers*
*Chairman, President, and Chief Executive Officer*

*By:* */s/Melissa K. Caen*
*(Melissa K. Caen, Attorney-in-fact)*

*Date:* *February 20, 2018*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

*W. Paul Bowers*
*Chairman, President, and Chief Executive Officer*
*(Principal Executive Officer)*

*Xia Liu*
*Executive Vice President, Chief Financial Officer,*
*and Treasurer*
*(Principal Financial Officer)*

*David P. Poroch*
*Comptroller and Vice President*
*(Principal Accounting Officer)*

*Directors:*

| | |
|---|---|
| *Mark L. Burns* | *Kessel D. Stelling, Jr.* |
| *Shantella E. Cooper* | *Jimmy C. Tallent* |
| *Lawrence L. Gellerstedt III* | *Charles K. Tarbutton* |
| *Stephen S. Green* | *Beverly Daniel Tatum* |
| *Douglas J. Hertz* | *Clyde C. Tuggle* |

*By:* */s/Melissa K. Caen*
*(Melissa K. Caen, Attorney-in-fact)*

*Date:* *February 20, 2018*

**GULF POWER COMPANY**

**SIGNATURES**

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

*GULF POWER COMPANY*

*By:* *S. W. Connally, Jr.*
*Chairman, President, and Chief Executive Officer*

*By:* */s/Melissa K. Caen*
*(Melissa K. Caen, Attorney-in-fact)*

*Date:* *February 20, 2018*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

*S. W. Connally, Jr.*
*Chairman, President, and Chief Executive Officer*
*(Principal Executive Officer)*

*Robin B. Boren*
*Vice President, Chief Financial Officer, and Treasurer*
*(Principal Financial Officer)*

*Paul D. Trippe*
*Comptroller*
*(Principal Accounting Officer)*

*Directors:*

*Allan G. Bense*
*Deborah H. Calder*
*William C. Cramer, Jr.*
*Julian B. MacQueen*
*J. Mort O'Sullivan, III*
*Michael T. Rehwinkel*
*Winston E. Scott*

*By:* */s/Melissa K. Caen*
*(Melissa K. Caen, Attorney-in-fact)*

*Date: February 20, 2018*

**Supplemental Information to be Furnished with Reports Filed Pursuant to Section 15(d) of the Act by Registrants Which Have Not Registered Securities Pursuant to Section 12 of the Act:**

Gulf Power Company is not required to send an annual report or proxy statement to its sole shareholder and parent company, The Southern Company, and will not prepare such a report after filing this Annual Report on Form 10-K for fiscal year 2017 . Accordingly, Gulf Power Company will not file an annual report with the Securities and Exchange Commission.

**MISSISSIPPI POWER COMPANY**

**SIGNATURES**

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

*MISSISSIPPI POWER COMPANY*

*By:* *Anthony L. Wilson*
*Chairman, President, and Chief Executive Officer*

*By:* */s/Melissa K. Caen*
*(Melissa K. Caen, Attorney-in-fact)*

*Date:* *February 20, 2018*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

*Anthony L. Wilson*
*Chairman, President, and Chief Executive Officer*
*(Principal Executive Officer)*

*Moses H. Feagin*
*Vice President, Treasurer, and*
*Chief Financial Officer*
*(Principal Financial Officer)*

*Cynthia F. Shaw*
*Comptroller*
*(Principal Accounting Officer)*

*Directors:*

| | |
|---|---|
| *Carl J. Chaney* | *Christine L. Pickering* |
| *L. Royce Cumbest* | *Phillip J. Terrell* |
| *Mark E. Keenum* | *M.L. Waters* |

*By:* */s/Melissa K. Caen*
*(Melissa K. Caen, Attorney-in-fact)*

*Date: February 20, 2018*

**SOUTHERN POWER COMPANY**

**SIGNATURES**

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

*SOUTHERN POWER COMPANY*

*By:* *Joseph A. Miller*
*Chairman, President and Chief Executive Officer*

*By:* */s/Melissa K. Caen*
*(Melissa K. Caen, Attorney-in-fact)*

*Date:* *February 20, 2018*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

*Joseph A. Miller*
*Chairman, President, and Chief Executive Officer*
*(Principal Executive Officer)*

*William C. Grantham*
*Senior Vice President, Chief Financial Officer, and Treasurer*
*(Principal Financial Officer)*

*Elliott L. Spencer*
*Comptroller and Corporate Secretary*
*(Principal Accounting Officer)*

*Directors:*

| | |
|---|---|
| *Art P. Beattie* | *James Y. Kerr, II* |
| *Thomas A. Fanning* | *Mark S. Lantrip* |
| *Kimberly S. Greene* | *Christopher C. Womack* |

*By:* */s/Melissa K. Caen*
*(Melissa K. Caen, Attorney-in-fact)*

*Date: February 20, 2018*

**SOUTHERN COMPANY GAS**

**SIGNATURES**

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

*SOUTHERN COMPANY GAS*

*By:* *Andrew W. Evans*
*Chairman, President, and Chief Executive Officer*

*By:* */s/Melissa K. Caen*
*(Melissa K. Caen, Attorney-in-fact)*

*Date:* *February 20, 2018*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

*Andrew W. Evans*
*Chairman, President, and Chief Executive Officer*
*(Principal Executive Officer)*

*Elizabeth W. Reese*
*Executive Vice President, Chief Financial Officer, and Treasurer*
*(Principal Financial Officer)*

*Grace A. Kolvereid*
*Senior Vice President and Comptroller*
*(Principal Accounting Officer)*

*Directors:*

| | |
|---|---|
| *Sandra N. Bane* | *Kimberly S. Greene* |
| *Thomas D. Bell, Jr.* | *John E. Rau* |
| *Charles R. Crisp* | *James A. Rubright* |
| *Brenda J. Gaines* | |

*By:* */s/Melissa K. Caen*
*(Melissa K. Caen, Attorney-in-fact)*

*Date: February 20, 2018*

**Supplemental Information to be Furnished with Reports Filed Pursuant to Section 15(d) of the Act by Registrants Which Have Not Registered Securities Pursuant to Section 12 of the Act:**

Southern Company Gas is not required to send an annual report or proxy statement to its sole shareholder and parent company, The Southern Company, and will not prepare such a report after filing this Annual Report on Form 10-K for fiscal year 2017 . Accordingly, Southern Company Gas will not file an annual report with the Securities and Exchange Commission.

**SOUTHERN POWER COMPANY**

**TO**

**WELLS FARGO BANK, NATIONAL ASSOCIATION,
TRUSTEE**

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**SEVENTEENTH SUPPLEMENTAL INDENTURE**

**DATED AS OF NOVEMBER 20, 2017**

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SERIES 2017A FLOATING RATE SENIOR NOTES

DUE DECEMBER 20, 2020

TABLE OF CONTENTS [1]



[1] This Table of Contents does not constitute part of the Indenture or have any bearing upon the interpretation of any of its terms and provisions.

THIS SEVENTEENTH SUPPLEMENTAL INDENTURE is made as of the 20 th day of November, 2017, by and between SOUTHERN POWER COMPANY, a Delaware corporation having its principal place of business at 30 Ivan Allen Jr. Blvd., N.W., Atlanta, Georgia 30308 (the “Company”), and WELLS FARGO BANK, NATIONAL ASSOCIATION, a national banking association, 150 East 42 nd Street, 40 th Floor, New York, New York 10017 (the “Trustee”).

W I T N E S S E T H:

WHEREAS, the Company has heretofore entered into a Senior Note Indenture, dated as of June 1, 2002 (the “Original Indenture”), with Wells Fargo Bank, National Association (as successor to The Bank of New York Mellon (formerly known as The Bank of New York)), as heretofore amended and supplemented;

WHEREAS, the Original Indenture is incorporated herein by this reference and the Original Indenture, as heretofore amended and supplemented and as further supplemented by this Seventeenth Supplemental Indenture, is herein called the “Indenture”;

WHEREAS, under the Original Indenture, a new series of unsecured senior debentures or notes or other evidence of indebtedness (the “Senior Notes”) may at any time be established by the Board of Directors of the Company in accordance with the provisions of the Original Indenture and the terms of such series may be described by a supplemental indenture executed by the Company and the Trustee;

WHEREAS, the Company proposes to create under the Indenture a new series of Senior Notes;

WHEREAS, additional Senior Notes of other series hereafter established, except as may be limited in the Original Indenture as at the time supplemented and modified, may be issued from time to time pursuant to the Indenture as at the time supplemented and modified; and

WHEREAS, all conditions necessary to authorize the execution and delivery of this Seventeenth Supplemental Indenture and to make it a valid and binding obligation of the Company have been done or performed.

NOW, THEREFORE, in consideration of the agreements and obligations set forth herein and for other good and valuable consideration, the sufficiency of which is hereby acknowledged, the parties hereto hereby agree as follows:

## ARTICLE 1

## SERIES 2017A SENIOR NOTES

SECTION 101. Establishment . There is hereby established a new series of Senior Notes to be issued under the Indenture, to be designated as the Company’s Series 2017A Floating Rate Senior Notes due December 20, 2020 (the “Series 2017A Notes”).

There are to be authenticated and delivered \$525,000,000 principal amount of Series 2017A Notes, and such principal amount of the Series 2017A Notes may be increased from time to time pursuant to Section 301 of the Original Indenture. All Series 2017A Notes need not be issued at the same time and such series may be reopened at any time, without the consent of any Holder, for issuances of additional Series 2017A Notes. Any such additional Series 2017A Notes will have the same interest rate, maturity and other terms as those initially issued (except for the public offering price and issue date and the initial interest accrual date and initial Interest Payment Date (as defined below), if applicable). No Series 2017A Notes shall be authenticated and delivered in excess of the principal amount as so increased except as provided by Sections 203, 303, 304, 907 or 1107 of the Original Indenture. The Series 2017A Notes shall be issued in fully registered form.

The Series 2017A Notes shall be issued in the form of one or more Global Securities in substantially the form set out in Exhibit A hereto. The Depositary with respect to the Series 2017A Notes shall be The Depository Trust Company.

The form of the Trustee's Certificate of Authentication for the Series 2017A Notes shall be in substantially the form set forth in Exhibit B hereto.

Each Series 2017A Note shall be dated the date of authentication thereof and shall bear interest from the date of original issuance thereof or from the most recent Interest Payment Date to which interest has been paid or duly provided for.

SECTION 102. Definitions . The following defined terms used herein shall, unless the context otherwise requires, have the meanings specified below. Capitalized terms used herein for which no definition is provided herein shall have the meanings set forth in the Original Indenture.

"1933 Act" has the meaning set forth in Section 106 of this Seventeenth Supplemental Indenture.

"Calculation Agent" means Wells Fargo Bank, National Association, or its successor appointed by the Company, acting as calculation agent.

"Distribution Compliance Period" has the meaning set forth in Section 107 of this Seventeenth Supplemental Indenture.

"Interest Determination Date" means the second London Business Day immediately preceding the first day of the relevant Interest Period.

"Interest Payment Dates" means the 20th day of March, June, September and December, commencing December 20, 2017; provided, however, in the event that any Interest Payment Date (other than the Interest Payment Date that is the Stated Maturity) would otherwise be a day that is not a Business Day, the Interest Payment Date will be the next succeeding Business Day.

"Interest Period" means the period commencing on an Interest Payment Date (or, with respect to the initial Interest Period only, commencing on the Original Issue Date) and ending on the day before the next succeeding Interest Payment Date.

"London Business Day" means a day that is a Business Day and a day on which dealings in deposits in U.S. dollars are transacted, or with respect to any future date are expected to be transacted, in the London interbank market.

"One-Month LIBOR" means, with respect to the initial Interest Period, the rate (expressed as a percentage per annum) for deposits in U.S. dollars having an index maturity of one month that appears on Reuters LIBOR01 Page as of 11:00 a.m. (London time) on the Interest Determination Date for the initial Interest Period. If such rate does not appear on the Reuters LIBOR01 Page as of 11:00 a.m. (London time) on the Interest Determination Date for the initial Interest Period, One-Month LIBOR will be determined on the basis of the rates at which deposits in U.S. dollars for the initial Interest Period and in a principal amount of not less than $1,000,000 are offered to prime banks in the London interbank market by four major banks in the London interbank market (which may include affiliates of one or more of the underwriters of the Series 2017A Notes) selected by the Company, at approximately 11:00 a.m., London time, on the Interest Determination Date for the initial Interest Period. The Calculation Agent will request the principal London office of each such bank to provide a quotation of its rate. If at least two such quotations are provided, One-Month LIBOR with respect to the initial Interest Period will be the arithmetic mean of such quotations. If fewer than two quotations are provided, One-Month LIBOR with respect to the initial Interest Period will be the arithmetic mean of the rates quoted by three major banks in New York City (which may include affiliates of one or more of the underwriters of the Series 2017A Notes) selected by the Company, at approximately 11:00 a.m., New York City time, on the Interest Determination Date for the initial Interest Period for loans in U.S. dollars to leading European banks for the initial Interest Period and in a principal amount of not less than $1,000,000.

"Original Issue Date" means November 20, 2017.

"Regular Record Date" means, with respect to each Interest Payment Date, the 15th calendar day preceding such Interest Payment Date (whether or not a Business Day).

"Regulation S Global Note" has the meaning set forth in Section 106 of this Seventeenth Supplemental Indenture.

"Regulation S Legend" has the meaning set forth in Section 106 of this Seventeenth Supplemental Indenture.

"Reuters LIBOR01 Page" means the display designated as Reuters LIBOR01 on the Reuters service (or such other page as may replace the Reuters LIBOR01 Page on that service, or such other service as may be nominated as the information vendor, for the purpose of displaying rates or prices comparable to the London Interbank Offered rate for U.S. dollar deposits).

"Rule 144A Global Note" has the meaning set forth in Section 106 of this Seventeenth Supplemental Indenture.

"Rule 144A Legend" has the meaning set forth in Section 106 of this Seventeenth Supplemental Indenture.

“Stated Maturity” means December 20, 2020; provided that if the Stated Maturity is not a Business Day, the principal and interest due on that date will be payable on the next succeeding Business Day, and no interest shall accrue for the intervening period; provided further that if such next succeeding Business Day is in the next succeeding calendar year, such payment will be made on the immediately preceding Business Day.

“Three-Month LIBOR” means, with respect to any Interest Period, the rate (expressed as a percentage per annum) for deposits in U.S. dollars having an index maturity of three months that appears on Reuters LIBOR01 Page as of 11:00 a.m. (London time) on the Interest Determination Date for that Interest Period. If such rate does not appear on the Reuters LIBOR01 Page as of 11:00 a.m. (London time) on the Interest Determination Date for that Interest Period, Three-Month LIBOR will be determined on the basis of the rates at which deposits in U.S. dollars for the Interest Period and in a principal amount of not less than $1,000,000 are offered to prime banks in the London interbank market by four major banks in the London interbank market (which may include affiliates of one or more of the underwriters of the Series 2017A Notes) selected by the Company, at approximately 11:00 a.m., London time, on the Interest Determination Date for that Interest Period. The Calculation Agent will request the principal London office of each such bank to provide a quotation of its rate. If at least two such quotations are provided, Three-Month LIBOR with respect to that Interest Period will be the arithmetic mean of such quotations. If fewer than two quotations are provided, Three-Month LIBOR with respect to that Interest Period will be the arithmetic mean of the rates quoted by three major banks in New York City (which may include affiliates of one or more of the underwriters of the Series 2017A Notes) selected by the Company, at approximately 11:00 a.m., New York City time, on the Interest Determination Date for that Interest Period for loans in U.S. dollars to leading European banks for that Interest Period and in a principal amount of not less than $1,000,000. However, if fewer than three banks selected by the Company to provide quotations are quoting as described above, Three-Month LIBOR for that Interest Period will be the same as the rate determined for the previous Interest Period.

SECTION 103. Payment of Principal and Interest . The principal of the Series 2017A Notes shall be due at Stated Maturity (unless earlier redeemed). The unpaid principal amount of the Series 2017A Notes shall bear interest at the rates set quarterly pursuant to Section 104 hereof until paid or duly provided for. Interest shall be paid quarterly in arrears on each Interest Payment Date to the Person in whose name the Series 2017A Notes are registered at the close of business on the Regular Record Date for such Interest Payment Date, *provided* that interest payable at the Stated Maturity or on a Redemption Date as provided herein will be paid to the Person to whom principal is payable. Any such interest that is not so punctually paid or duly provided for will forthwith cease to be payable to the Holders on such Regular Record Date and may either be paid to the Person or Persons in whose name the Series 2017A Notes are registered at the close of business on a Special Record Date for the payment of such defaulted interest to be fixed by the Trustee, notice whereof shall be given to Holders of the Series 2017A Notes not less than ten (10) days prior to such Special Record Date, or be paid at any time in any other lawful manner not inconsistent with the requirements of any securities exchange, if any, on which the Series 2017A Notes shall be listed, and upon such notice as may be required by any such exchange, all as more fully provided in the Original Indenture.

Payments of interest on the Series 2017A Notes will include interest accrued to but excluding the respective Interest Payment Dates. Interest payments for the Series 2017A Notes shall be computed and paid on the basis of the actual number of days elapsed over a 360-day year.

Payment of the principal and interest due at the Stated Maturity or earlier redemption of the Series 2017A Notes shall be made upon surrender of the Series 2017A Notes at the Corporate Trust Office of the Trustee. The principal of and interest on the Series 2017A Notes shall be paid in such coin or currency of the United States of America as at the time of payment is legal tender for payment of public and private debts. Payments of interest (including interest on any Interest Payment Date) will be made, subject to such surrender where applicable, at the option of the Company, (i) by check mailed to the address of the Person entitled thereto as such address shall appear in the Security Register or (ii) by wire transfer or other electronic transfer at such place and to such account at a banking institution in the United States as may be designated in writing to the Trustee at least sixteen (16) days prior to the date for payment by the Person entitled thereto.

SECTION 104. Determination of Interest. The Series 2017A Notes will bear interest for each Interest Period at a per annum rate determined by the Calculation Agent, subject to the maximum interest rate permitted by New York or other applicable state law, as such law may be modified by United States law of general application. The interest rate applicable during each Interest Period (other than the initial Interest Period) will be equal to Three-Month LIBOR on the Interest Determination Date for such Interest Period plus 0.55%. The interest rate applicable during the initial Interest Period will be equal to One-Month LIBOR on the Interest Determination Date for the initial Interest Period (the second London Business Day prior to the Original Issue Date) plus 0.55%. In no event shall the applicable interest rate be less than 0% for any Interest Period. Promptly upon such determination, the Calculation Agent will notify the Company and the Trustee, if the Trustee is not then serving as the Calculation Agent, of the interest rate for the new Interest Period. The interest rate determined by the Calculation Agent, absent manifest error, shall be binding and conclusive upon the beneficial owners and Holders of the Series 2017A Notes, the Company and the Trustee.

Upon the request of a Holder of the Series 2017A Notes, the Calculation Agent will provide to such Holder the interest rate in effect on the date of such request and, if determined, the interest rate for the next Interest Period.

SECTION 105. Denominations. The Series 2017A Notes may be issued in denominations of $2,000 and integral multiples of $1,000 in excess thereof.

SECTION 106. Global Securities. The Series 2017A Notes will be issued in the form of one or more Global Securities registered in the name of the Depositary (which shall be The Depository Trust Company) or its nominee. The Series 2017A Notes will be initially issued pursuant to an exemption or exemptions from the registration requirements of the Securities Act of 1933, as amended (the “1933 Act”). Beneficial interests in the Series 2017A Notes offered and sold to “qualified institutional buyers” (as defined in Rule 144A under the 1933 Act) in reliance upon Rule

144A under the 1933 Act shall be represented by one or more separate Global Securities (each, a "Rule 144A Global Note"). Each Rule 144A Global Note shall bear the Rule 144A legend in substantially the form set forth in Exhibit A hereto (the "Rule 144A Legend"). Beneficial interests in the Series 2017A Notes offered and sold to purchasers outside of the United States pursuant to Regulation S under the 1933 Act shall be represented by one or more separate Global Securities (each, a "Regulation S Global Note") and shall bear the Regulation S legend in substantially the form set forth in Exhibit A hereto (the "Regulation S Legend").

Except under the limited circumstances described below, Series 2017A Notes represented by one or more Global Securities will not be exchangeable for, and will not otherwise be issuable as, Series 2017A Notes in definitive form. The Global Securities described above may not be transferred except by the Depositary to a nominee of the Depositary or by a nominee of the Depositary to the Depositary or another nominee of the Depositary or to a successor Depositary or its nominee.

Owners of beneficial interests in such a Global Security will not be considered the Holders thereof for any purpose under the Indenture, and no Global Security representing a Series 2017A Note shall be exchangeable, except for another Global Security of like denomination and tenor to be registered in the name of the Depositary or its nominee or to a successor Depositary or its nominee. The rights of Holders of such Global Security shall be exercised only through the Depositary.

Subject to the procedures of the Depositary, a Global Security shall be exchangeable for Series 2017A Notes registered in the names of persons other than the Depositary or its nominee only if (i) the Depositary notifies the Company that it is unwilling or unable to continue as a Depositary for such Global Security and no successor Depositary shall have been appointed by the Company, or if at any time the Depositary ceases to be a clearing agency registered under the Securities Exchange Act of 1934, as amended, at a time when the Depositary is required to be so registered to act as such Depositary and no successor Depositary shall have been appointed by the Company, in each case within 90 days after the Company receives such notice or becomes aware of such cessation, (ii) the Company in its sole discretion determines that such Global Security shall be so exchangeable, or (iii) there shall have occurred an Event of Default with respect to the Series 2017A Notes. Any Global Security that is exchangeable pursuant to the preceding sentence shall be exchangeable for Series 2017A Notes registered in such names as the Depositary shall direct.

Neither the Company, the Trustee nor any agent of the Company or the Trustee shall have any responsibility or liability for any aspect of the records relating to or payments made on account of beneficial ownership interests in a Global Security or for maintaining, supervising or reviewing any records relating to such beneficial ownership interests.

SECTION 107. Transfer. A Rule 144A Global Note may not be transferred on the Security Register except in compliance with the restrictions on transfer contained in the Rule 144A Legend and upon receipt by the Security Registrar of a completed and executed Transfer Certificate in the form contained in Exhibit A hereto. Prior to the expiration of 40 days beginning on and including the later of (i) the day on which the offering of the Series 2017A Notes commences and (ii) the Original Issue Date (the "Distribution Compliance Period"), a Regulation S Global Note may not be transferred on the Security Register except in compliance with the restrictions on transfer contained in the Regulation S Legend and upon receipt by the Security Registrar of a completed and executed Transfer Certificate in the form contained in Exhibit A hereto. No service charge will be made for any transfer or exchange of Series 2017A Notes, but payment will be required of a sum sufficient to cover any tax or other governmental charge that may be imposed in connection therewith.

The transfer and exchange of beneficial interests in the Global Securities shall be effected through the Depositary, in accordance with this Seventeenth Supplemental Indenture (including applicable restrictions on transfer set forth herein, if any) and the procedures of the Depositary therefor.

Until the expiration of the Distribution Compliance Period, transfers by an owner of a beneficial interest in a Regulation S Global Note to a transferee who takes delivery of such interest through a Rule 144A Global Note will be made only upon receipt by the Trustee of a completed and executed Transfer Certificate in the form contained in Exhibit A hereto from the transferor of the beneficial interest to the effect that such transfer is being made to a person whom the transferor reasonably believes is a qualified institutional buyer (as defined in Rule 144A under the Securities Act) in a transaction meeting the requirements of Rule 144A and the requirements of applicable securities laws of any state of the United States or any other jurisdiction.

Transfers by an owner of a beneficial interest in the Rule 144A Global Note to a transferee who takes delivery through the Regulation S Global Note, whether before or after the expiration of the Distribution Compliance Period, will be made only upon receipt by the Trustee of a Transfer Certificate in the form contained in Exhibit A hereto from the transferor to the effect that such transfer is being made in accordance with Regulation S or Rule 144 under the Securities Act and that, if such transfer is being made prior to the expiration of the Distribution Compliance Period, the interest transferred will be held immediately thereafter through Euroclear Bank S.A./N.V., as operator of the Euroclear System or Clearstream Banking, société anonyme, Luxembourg.

Any beneficial interest in one of the Global Securities that is transferred to a person who takes delivery in the form of an interest in another Global Security will, upon transfer, cease to be an interest in the initial Global Security and will become an interest in the other Global Security and, accordingly, will thereafter be subject to all transfer restrictions, if any, and other procedures applicable to beneficial interests in such other Global Security for as long as it remains such an interest.

Transfers of beneficial interests between a Rule 144A Global Note and a Regulation S Global Note, and other transfers relating to beneficial interests in the Global Securities, shall be reflected by endorsements of the Trustee, as custodian for The Depository Trust Company, on the schedules attached to such Rule 144A Global Note and Regulation S Global Note.

Neither the Trustee, the Security Registrar nor any transfer agent shall have any obligation or duty to monitor, determine or inquire as to compliance with any restrictions on transfer imposed under the Indenture or under applicable law with respect to any transfer of any interest in any Series 2017A Note (including any transfers between or among Depositary participants, members or beneficial owners in any Global Security) other than to require delivery of such certificates and other documentation or evidence as are expressly required by, and to do so if and when expressly required by, the terms of the Indenture, and to examine the same to determine substantial compliance as to form with the express requirements hereof.

Neither the Company nor the Trustee shall have any liability for acts or omissions of the Depositary, for the Depositary records of beneficial interest, for any transactions between the Depositary, any participant member of the Depositary and/or beneficial owner of any interest in any Series 2017A Notes, or in respect of any transfers effected by the Depositary or by any participant member of the Depositary or any beneficial owner of any interest in any Series 2017A Notes held through any such participant member of the Depositary.

The Company shall not be required (a) to issue, register the transfer of or exchange any Series 2017A Notes during a period beginning at the opening of business fifteen (15) days before the date of the mailing of a notice pursuant to Section 1104 of the Original Indenture identifying the serial numbers of the Series 2017A Notes to be called for redemption, and ending at the close of business on the date of the mailing, or (b) to register the transfer of or exchange any Series 2017A Notes theretofore selected for redemption in whole or in part, except the unredeemed portion of any Series 2017A Notes redeemed in part.

SECTION 108. Redemption at the Company's Option. At any time and from time to time on or after December 20, 2018, the Series 2017A Notes will be subject to redemption, at the option of the Company, in whole or in part, upon not less than 15 nor more than 60 days' notice, at a redemption price equal to 100% of the principal amount of the Series 2017A Notes being redeemed plus accrued and unpaid interest on the Series 2017A Notes being redeemed to the Redemption Date.

If the Redemption Date is not a Business Day, the principal and interest due on that date will be payable on the next succeeding Business Day, and no interest shall accrue for the intervening period; provided, however, that if such next succeeding Business Day is in the next succeeding calendar year, such payment will be made on the immediately preceding Business Day.

In the event of redemption of the Series 2017A Notes in part only, a new Series 2017A Note or Notes for the unredeemed portion will be issued in the name or names of the Holders thereof upon the surrender thereof.

The Series 2017A Notes will not have a sinking fund.

Except as otherwise provided herein, notice of redemption shall be given as provided in Section 1104 of the Original Indenture.

Any redemption of less than all of the Series 2017A Notes shall, with respect to the principal thereof, be divisible by $1,000.

SECTION 109. Information to Holders. Upon the request of any Holder, any holder of a beneficial interest in the Series 2017A Notes, or the Trustee (on behalf of a Holder or a holder of a beneficial interest in the Series 2017A Notes), the Company will furnish such information as is specified in paragraph (d)(4) of Rule 144A promulgated under the 1933 Act to Holders (and to holders of beneficial interests in the Series 2017A Notes), to prospective purchasers of the Series 2017A Notes (and of beneficial interests in the Series 2017A Notes) who are qualified institutional buyers or to the Trustee for delivery to such Holder or prospective purchasers of the Series 2017A Notes or beneficial interests therein, as the case may be, unless, at the time of such request, the Company is subject to the reporting requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended.

Delivery of information to the Trustee pursuant to this Section 109 is for informational purposes only and the Trustee's receipt of such shall not constitute constructive notice of any information contained therein or determinable from information contained therein, including the Company's compliance with any of its covenants under the Indenture.

## ARTICLE 2

## MISCELLANEOUS PROVISIONS

SECTION 201. Recitals by Company. The recitals in this Seventeenth Supplemental Indenture are made by the Company only and not by the Trustee, and all of the provisions contained in the Original Indenture in respect of the rights, privileges, immunities, powers and duties of the Trustee shall be applicable in respect of Series 2017A Notes and of this Seventeenth Supplemental Indenture as fully and with like effect as if set forth herein in full.

SECTION 202. Ratification and Incorporation of Original Indenture. As supplemented hereby, the Original Indenture is in all respects ratified and confirmed, and the Original Indenture as supplemented by this Seventeenth Supplemental Indenture shall be read, taken and construed as one and the same instrument.

SECTION 203. Executed in Counterparts. This Seventeenth Supplemental Indenture may be simultaneously executed in several counterparts, each of which shall be deemed to be an original, and such counterparts shall together constitute but one and the same instrument.

SECTION 204. Legends. Except as determined by the Company in accordance with applicable law, each Series 2017A Note shall bear the applicable legends relating to restrictions on transfer pursuant to the securities laws in substantially the form set forth on Exhibit A hereto.

IN WITNESS WHEREOF, each party hereto has caused this instrument to be signed in its name and behalf by its duly authorized officer, all as of the day and year first above written.

SOUTHERN POWER COMPANY

By: /s/William C. Grantham

William C. Grantham
Senior Vice President, Treasurer and
Chief Financial Officer

WELLS FARGO BANK, NATIONAL
ASSOCIATION, as Trustee

By: /s/Stefan Victory

Stefan Victory
Vice President

EXHIBIT A

FORM OF SERIES 2017A NOTE

[RULE 144A LEGEND FOR USE WITH RULE 144A GLOBAL NOTES]

NEITHER THIS NOTE NOR ANY BENEFICIAL INTEREST HEREIN HAS BEEN REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE “1933 ACT”). EACH HOLDER HEREOF, AND EACH OWNER OF A BENEFICIAL INTEREST HEREIN, BY PURCHASING THIS NOTE, AGREES FOR THE BENEFIT OF SOUTHERN POWER COMPANY (THE “COMPANY”) THAT THIS NOTE MAY NOT BE RESOLD, PLEDGED OR OTHERWISE TRANSFERRED PRIOR TO THE DATE WHICH IS SIX MONTHS (IF ALL APPLICABLE CONDITIONS TO SUCH RESALE UNDER RULE 144 UNDER THE 1933 ACT (OR ANY SUCCESSOR PROVISION THEREOF) ARE SATISFIED) AFTER THE LATER OF THE ORIGINAL ISSUANCE DATE THEREOF, THE ISSUANCE DATE OF ANY SUBSEQUENT ISSUANCE OF ADDITIONAL NOTES OF THE SAME SERIES AND THE LAST DATE ON WHICH THE COMPANY OR ANY AFFILIATE THEREOF WAS THE OWNER OF THIS NOTE OR THE EXPIRATION OF SUCH SHORTER PERIOD AS MAY BE PRESCRIBED BY SUCH RULE 144 (OR SUCH SUCCESSOR PROVISION) PERMITTING RESALES OF THIS NOTE WITHOUT ANY CONDITIONS (THE “RESALE RESTRICTION TERMINATION DATE”) OTHER THAN (A)(1) TO THE COMPANY, (2) IN A TRANSACTION ENTITLED TO AN EXEMPTION FROM REGISTRATION PROVIDED BY RULE 144 UNDER THE 1933 ACT (IF AVAILABLE), (3) SO LONG AS THIS NOTE IS ELIGIBLE FOR RESALE PURSUANT TO RULE 144A UNDER THE 1933 ACT (“RULE 144A”), TO A PERSON WHOM THE SELLER REASONABLY BELIEVES IS A QUALIFIED INSTITUTIONAL BUYER WITHIN THE MEANING OF RULE 144A PURCHASING FOR ITS OWN ACCOUNT OR FOR THE ACCOUNT OF A QUALIFIED INSTITUTIONAL BUYER TO WHOM NOTICE IS GIVEN THAT THE RESALE, PLEDGE OR OTHER TRANSFER IS BEING MADE IN RELIANCE ON RULE 144A UNDER THE 1933 ACT (AS INDICATED BY THE BOX CHECKED BY THE TRANSFEROR ON THE CERTIFICATE OF TRANSFER ATTACHED TO THIS NOTE), (4) IN AN OFFSHORE TRANSACTION IN ACCORDANCE WITH RULE 903 OR 904 OF REGULATION S UNDER THE 1933 ACT (AS INDICATED BY THE BOX CHECKED BY THE TRANSFEROR ON THE CERTIFICATE OF TRANSFER ATTACHED TO THIS NOTE), (5) IN ACCORDANCE WITH ANOTHER APPLICABLE EXEMPTION FROM THE REGISTRATION REQUIREMENTS OF THE 1933 ACT (AND BASED UPON AN OPINION OF COUNSEL ACCEPTABLE TO THE COMPANY), OR (6) PURSUANT TO AN EFFECTIVE REGISTRATION STATEMENT UNDER THE 1933 ACT AND (B) IN EACH CASE IN ACCORDANCE WITH ANY APPLICABLE SECURITIES LAWS OF ANY STATE OF THE UNITED STATES. THE FOREGOING RESTRICTIONS ON RESALE WILL NOT APPLY SUBSEQUENT TO THE RESALE RESTRICTION TERMINATION DATE. THE HOLDER HEREOF, BY PURCHASING THIS NOTE, REPRESENTS AND AGREES FOR THE BENEFIT OF THE COMPANY THAT IT IS (i) A QUALIFIED INSTITUTIONAL BUYER WITHIN THE MEANING OF RULE 144A UNDER THE 1933 ACT OR (ii) A NON-U.S. PERSON OUTSIDE THE UNITED STATES WITHIN THE MEANING OF, OR AN ACCOUNT SATISFYING THE

REQUIREMENTS OF, PARAGRAPH (k)(2) OF RULE 902 UNDER REGULATION S UNDER THE 1933 ACT. THE HOLDER OF THIS NOTE ACKNOWLEDGES THAT THE COMPANY OR THE TRUSTEE RESERVES THE RIGHT PRIOR TO ANY OFFER, SALE OR OTHER TRANSFER (1) PURSUANT TO CLAUSE (A)(2) PRIOR TO THE RESALE RESTRICTION TERMINATION DATE TO REQUIRE THE DELIVERY OF AN OPINION OF COUNSEL, CERTIFICATIONS OR OTHER INFORMATION SATISFACTORY TO THE COMPANY AND THE TRUSTEE AND (2) IN EACH OF THE FOREGOING CASES, TO REQUIRE THAT A CERTIFICATE AS TO COMPLIANCE WITH CERTAIN CONDITIONS TO TRANSFER IS COMPLETED AND DELIVERED BY THE TRANSFEROR TO THE COMPANY AND THE TRUSTEE.

[REGULATION S LEGEND FOR USE WITH REGULATION S GLOBAL NOTES]

THE SECURITIES COVERED HEREBY HAVE NOT BEEN REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE “1933 ACT”), AND MAY NOT BE OFFERED OR SOLD WITHIN THE UNITED STATES OR TO, OR FOR THE ACCOUNT OR BENEFIT OF, U.S. PERSONS (I) AS PART OF THEIR DISTRIBUTION AT ANY TIME OR (II) OTHERWISE UNTIL 40 DAYS AFTER THE LATER OF THE DATE OF THE COMMENCEMENT OF THE OFFERING OF THE SECURITIES AND THE DATE OF ORIGINAL ISSUANCE OF THE SECURITIES, EXCEPT IN EITHER CASE IN ACCORDANCE WITH REGULATION S OR RULE 144A UNDER THE 1933 ACT OR ANY OTHER AVAILABLE EXEMPTION FROM REGISTRATION UNDER THE 1933 ACT. TERMS USED ABOVE HAVE THE MEANINGS GIVEN TO THEM BY REGULATION S.

NO. _______ CUSIP NO. ___________________

SOUTHERN POWER COMPANY
SERIES 2017A FLOATING RATE SENIOR NOTE
DUE DECEMBER 20, 2020

| | |
|---|---|
| Initial Principal Amount: | $_____________ |
| Regular Record Date: | 15th calendar day prior to the applicable Interest Payment Date (whether or not a Business Day) |
| Original Issue Date: | November 20, 2017 |
| Stated Maturity: | December 20, 2020; provided that if the Stated Maturity is not a Business Day, the principal and interest due on that date will be payable on the next succeeding Business Day, and no interest shall accrue for the intervening period; provided further that if such next succeeding Business Day is in the next succeeding calendar year, such payment will be made on the immediately preceding Business Day. |
| Interest Payment Dates: | 20 th day of March, June, September and December; provided, however, in the event that any Interest Payment Date (other than the Interest Payment Date that is the Stated Maturity) would otherwise be a day that is not a Business Day, the Interest Payment Date will be the next succeeding Business Day |
| Interest Rate: | One-Month LIBOR (for the initial Interest Period) and Three-Month LIBOR (for subsequent Interest Periods), in each case plus 0.55% per annum and as set on each Interest Determination Date |
| Authorized Denominations: | $2,000 or any integral multiple of $1,000 in excess thereof |

Southern Power Company, a Delaware corporation (the "Company," which term includes any successor corporation under the Indenture referred to on the reverse hereof), for value received, hereby promises to pay to ___________________________________, or registered assigns, the principal sum of _______________________________ DOLLARS ($__________), or such other amount as indicated on the Schedule of Increases or Decreases in Global Security attached hereto as Schedule I, on the Stated Maturity shown above (or upon earlier redemption), and to pay interest thereon from the Original Issue Date shown above, or from the most recent Interest Payment Date to which interest has been paid or duly provided for, quarterly in arrears on each Interest Payment Date as specified above, commencing on December 20, 2017 and on the Stated Maturity (or upon earlier redemption) at the rates per annum determined in accordance with the provisions specified below until the principal hereof is paid or made available for payment and at such rates on any overdue principal and on any overdue installment of interest. The interest so payable, and punctually paid or duly provided for, on any Interest Payment Date (other than an Interest Payment Date that is the Stated Maturity or on a Redemption Date) will, as provided in such Indenture, be paid to the Person in whose name this Note (the "Note") is registered at the close of business on the Regular Record Date as specified above next preceding such Interest Payment Date, provided that any interest payable at the Stated Maturity or on any Redemption Date will be paid to the Person to whom principal is payable. Except as otherwise provided in the Indenture, any such interest not so punctually paid or duly provided for will forthwith cease to be payable to the Holder on such Regular Record Date and may either be paid to the Person in whose name this Note is registered at the close of business on a Special Record Date for the payment of such defaulted interest to be fixed by the Trustee, notice whereof shall be given to Holders of Notes of this series not less than 10 days prior to such Special Record Date, or be paid at any time in any other lawful manner not inconsistent with the requirements of any securities exchange, if any, on which the Notes of this series shall be listed, and upon such notice as may be required by any such exchange, all as more fully provided in the Indenture.

The Series 2017A Notes (as defined on the reverse hereof) will bear interest for each Interest Period at a per annum rate determined by the Calculation Agent, subject to the maximum interest rate permitted by New York or other applicable state law, as such law may be modified by United States law of general application. The interest rate applicable during each Interest Period (other than the initial Interest Period) will be equal to Three-Month LIBOR on the Interest Determination Date for such Interest Period plus 0.55%. The interest rate applicable during the initial Interest Period will be equal to One-Month LIBOR on the Interest Determination Date for the initial Interest Period (the second London Business Day prior to the Original Issue Date) plus 0.55%. In no event shall the applicable interest rate be less than 0% for any Interest Period. Promptly upon such determination, the Calculation Agent will notify the Company and the Trustee, if the Trustee is not then serving as the Calculation Agent, of the interest rate for the new Interest Period. The interest rate determined by the Calculation Agent, absent manifest error, shall be binding and conclusive upon the beneficial owners and Holders of the Series 2017A Notes, the Company and the Trustee.

"Calculation Agent" means The Wells Fargo Bank, National Association, or its successor appointed by the Company, acting as calculation agent.

"Interest Determination Date" means the second London Business Day immediately preceding the first day of the relevant Interest Period.

"Interest Period" means the period commencing on an Interest Payment Date (or, with respect to the initial Interest Period only, commencing on the Original Issue Date) and ending on the day before the next succeeding Interest Payment Date.

"London Business Day" means a day that is a Business Day and a day on which dealings in deposits in U.S. dollars are transacted, or with respect to any future date are expected to be transacted, in the London interbank market.

"One-Month LIBOR" means, with respect to the initial Interest Period, the rate (expressed as a percentage per annum) for deposits in U.S. dollars having an index maturity of one month that appears on Reuters LIBOR01 Page as of 11:00 a.m. (London time) on the Interest Determination Date for the initial Interest Period. If such rate does not appear on the Reuters LIBOR01 Page as of 11:00 a.m. (London time) on the Interest Determination Date for the initial Interest Period, One-Month LIBOR will be determined on the basis of the rates at which deposits in U.S. dollars for the initial Interest Period and in a principal amount of not less than $1,000,000 are offered to prime banks in the London interbank market by four major banks in the London interbank market (which may include affiliates of one or more of the underwriters of the Series 2017A Notes) selected by the Company, at approximately 11:00 a.m., London time, on the Interest Determination Date for the initial Interest Period. The Calculation Agent will request the principal London office of each such bank to provide a quotation of its rate. If at least two such quotations are provided, One-Month LIBOR with respect to the initial Interest Period will be the arithmetic mean of such quotations. If fewer than two quotations are provided, One-Month LIBOR with respect to the initial Interest Period will be the arithmetic mean of the rates quoted by three major banks in New York City (which may include affiliates of one or more of the underwriters of the Series 2017A Notes) selected by the Company, at approximately 11:00 a.m., New York City time, on the Interest Determination Date for the initial Interest Period for loans in U.S. dollars to leading European banks for the initial Interest Period and in a principal amount of not less than $1,000,000.

"Reuters LIBOR01 Page" means the display designated as Reuters LIBOR01 on the Reuters service (or such other page as may replace the Reuters LIBOR01 Page on that service, or such other service as may be nominated as the information vendor, for the purpose of displaying rates or prices comparable to the London Interbank Offered rate for U.S. dollar deposits).

"Three-Month LIBOR" means, with respect to any Interest Period, the rate (expressed as a percentage per annum) for deposits in U.S. dollars having an index maturity of three months that appears on Reuters LIBOR01 Page as of 11:00 a.m. (London time) on the Interest Determination Date for that Interest Period. If such rate does not appear on the Reuters LIBOR01 Page as of 11:00 a.m. (London time) on the Interest Determination Date for that Interest Period, Three-Month LIBOR will be determined on the basis of the rates at which deposits in U.S. dollars for the Interest Period and in a principal amount of not less than $1,000,000 are offered to prime banks in the London interbank market by four major banks in the London interbank market (which may include affiliates of one or more of the underwriters of the Series 2017A Notes) selected by the Company, at approximately 11:00 a.m., London time, on the Interest Determination Date for that Interest Period. The Calculation Agent will request the principal London office of each such bank to provide a quotation of its rate. If at least two such quotations are provided, Three-Month LIBOR with respect to that Interest Period will be the arithmetic mean of such quotations. If fewer than two quotations are provided, Three-Month LIBOR with respect to that Interest Period will be the arithmetic mean of the rates quoted by three major banks in New York City (which may include affiliates of one or more of the underwriters of the Series 2017A Notes) selected by the Company, at approximately 11:00 a.m., New York City time, on the Interest Determination Date for that Interest Period for loans in U.S. dollars to leading European banks for that Interest Period and in a principal amount of not less than $1,000,000. However, if fewer than three banks selected by the Company to provide quotations are quoting as described above, Three-Month LIBOR for that Interest Period will be the same as the rate determined for the previous Interest Period.

Payments of interest on this Note will include interest accrued to but excluding the respective Interest Payment Dates. Interest payments for this Note shall be computed and paid on the basis of the actual number of days elapsed over a 360-day year. A “Business Day” shall mean any day other than a Saturday or a Sunday or a day on which banking institutions in New York City are authorized or required by law or executive order to remain closed or a day on which the Corporate Trust Office of the Trustee is closed for business.

Payment of the principal of and interest due at the Stated Maturity or earlier redemption of the Series 2017A Notes shall be made upon surrender of the Series 2017A Notes at the Corporate Trust Office of the Trustee. The principal of and interest on the Series 2017A Notes shall be paid in such coin or currency of the United States of America as at the time of payment is legal tender for payment of public and private debts. Payment of interest (including interest on an Interest Payment Date) will be made, subject to such surrender where applicable, at the option of the Company, (i) by check mailed to the address of the Person entitled thereto as such address shall appear in the Security Register or (ii) by wire transfer or other electronic transfer at such place and to such account at a banking institution in the United States as may be designated in writing to the Trustee at least 16 days prior to the date for payment by the Person entitled thereto.

REFERENCE IS HEREBY MADE TO THE FURTHER PROVISIONS OF THIS NOTE SET FORTH ON THE REVERSE HEREOF, WHICH FURTHER PROVISIONS SHALL FOR ALL PURPOSES HAVE THE SAME EFFECT AS IF SET FORTH AT THIS PLACE.

Unless the certificate of authentication hereon has been executed by the Trustee by manual signature, this Note shall not be entitled to any benefit under the Indenture or be valid or obligatory for any purpose.

IN WITNESS WHEREOF, the Company has caused this instrument to be duly executed under its corporate seal.

Dated:

SOUTHERN POWER COMPANY

By: ______________________________

Title:

Attest:

______________________________

Title:

{Seal of SOUTHERN POWER COMPANY appears here}

CERTIFICATE OF AUTHENTICATION

This is one of the Senior Notes referred to in the within-mentioned Indenture.

WELLS FARGO BANK, NATIONAL
ASSOCIATION, as Trustee

Dated: By: ______________________________

Authorized Signatory

(Reverse Side of Note)

This Note is one of a duly authorized issue of Senior Notes of the Company (the "Notes"), issued and issuable in one or more series under a Senior Note Indenture (the "Original Indenture"), dated as of June 1, 2002, as amended and supplemented, including by a Seventeenth Supplemental Indenture dated as of November 20, 2017 (the "Indenture"), between the Company and Wells Fargo Bank, National Association (as successor to The Bank of New York Mellon (formerly known as The Bank of New York)), as Trustee (the "Trustee," which term includes any successor trustee under the Indenture), to which Indenture and all indentures incidental thereto reference is hereby made for a statement of the respective rights, limitation of rights, duties and immunities thereunder of the Company, the Trustee and the Holders of the Notes issued thereunder and of the terms upon which said Notes are, and are to be, authenticated and delivered. This Note is one of the series designated on the face hereof as Series 2017A Floating Rate Senior Notes due December 20, 2020 (the "Series 2017A Notes") which is unlimited in aggregate principal amount. Capitalized terms used herein for which no definition is provided herein shall have the meanings set forth in the Indenture.

At any time and from time to time on or after December 20, 2018, the Series 2017A Notes will be subject to redemption, at the option of the Company, in whole or in part, upon not less than 15 nor more than 60 days' notice, at a redemption price equal to 100% of the principal amount of the Series 2017A Notes being redeemed plus accrued and unpaid interest on the Series 2017A Notes being redeemed to the Redemption Date.

If the Redemption Date is not a Business Day, the principal and interest due on that date will be payable on the next succeeding Business Day, and no interest shall accrue for the intervening period; provided, however, that if such next succeeding Business Day is in the next succeeding calendar year, such payment will be made on the immediately preceding Business Day.

In the event of redemption of this Note in part only, a new Note or Notes of this series for the unredeemed portion hereof will be issued in the name of the Holder hereof upon the surrender hereof. The Series 2017A Notes will not have a sinking fund.

If an Event of Default with respect to the Notes of this series shall occur and be continuing, the principal of the Notes of this series may be declared due and payable in the manner, with the effect and subject to the conditions provided in the Indenture.

The Indenture permits, with certain exceptions as therein provided, the amendment thereof and the modification of the rights and obligations of the Company and the rights of the Holders of the Notes of each series to be affected under the Indenture at any time by the Company and the Trustee with the consent of the Holders of not less than a majority in principal amount of the Notes at the time Outstanding of each series to be affected. The Indenture also contains provisions permitting the Holders of specified percentages in principal amount of the Notes of each series at the time Outstanding, on behalf of the Holders of all Notes of such series, to waive compliance by the Company with certain provisions of the Indenture and certain past defaults under the Indenture and their consequences. Any such consent or waiver by the Holder of this Note shall be conclusive and binding upon such Holder and upon all future Holders of this Note and of any Note issued upon the registration of transfer hereof or in exchange hereof or in lieu hereof, whether or not notation of such consent or waiver is made upon this Note.

No reference herein to the Indenture and no provision of this Note or of the Indenture shall alter or impair the obligation of the Company, which is absolute and unconditional, to pay the principal of and interest on this Note at the times, place and rates, and in the coin or currency, herein prescribed.

As provided in the Indenture and subject to certain limitations therein set forth, the transfer of this Note is registrable in the Security Register, upon surrender of this Note for registration of transfer at the office or agency of the Company for such purpose, duly endorsed by, or accompanied by a written instrument of transfer in form satisfactory to the Company and the Security Registrar and duly executed by, the Holder hereof or his attorney duly authorized in writing, together with the completed and executed Transfer Certificate attached hereto (as applicable), and thereupon one or more new Notes of this series, of authorized denominations and of like tenor and for the same aggregate principal amount, will be issued to the designated transferee or transferees. No service charge shall be made for any such registration of transfer or exchange, but the Company may require payment of a sum sufficient to cover any tax or other governmental charge payable in connection therewith.

Prior to due presentment of this Note for registration of transfer, the Company, the Trustee and any agent of the Company or the Trustee may treat the Person in whose name this Note is registered as the owner hereof for all purposes, whether or not this Note be overdue, and neither the Company, the Trustee nor any such agent shall be affected by notice to the contrary.

The Notes of this series are issuable only in registered form without coupons in denominations of $2,000 and any integral multiple of $1,000 in excess thereof. As provided in the Indenture and subject to certain limitations therein set forth, Notes of this series are exchangeable for a like aggregate principal amount of Notes of this series of a different authorized denomination, as requested by the Holder surrendering the same upon surrender of the Note or Notes to be exchanged at the office or agency of the Company.

This Note shall be governed by, and construed in accordance with, the internal laws of the State of New York.

**ABBREVIATIONS**

The following abbreviations, when used in the inscription on the face of this instrument, shall be construed as though they were written out in full according to applicable laws or regulations:

| | | |
|---|---|---|
| TEN COM- | as tenants in common | UNIF GIFT MIN ACT- _______ Custodian ________<br>(Cust) (Minor) |
| TEN ENT- | as tenants by the entireties | |
| JT TEN- | as joint tenants with right of survivorship and not as tenants in common | under Uniform Gifts to Minors Act<br>___________________<br>(State) |

Additional abbreviations may also be used though not on the above list.

FOR VALUE RECEIVED, the undersigned hereby sell(s) and transfer(s) unto

______________________________________________________________________________

(please insert Social Security or other identifying number of assignee)

______________________________________________________________________________

PLEASE PRINT OR TYPEWRITE NAME AND ADDRESS, INCLUDING POSTAL ZIP CODE OF ASSIGNEE

______________________________________________________________________________

______________________________________________________________________________

the within Note and all rights thereunder, hereby irrevocably constituting and appointing

______________________________________________________________________________

______________________________________________________________________________

agent to transfer said Note on the books of the Company, with full power of substitution in the premises.

Dated: _________________________ ________________________________________

________________________________________

NOTICE: The signature to this assignment must correspond with the name as written upon the face of the within instrument in every particular without alteration or enlargement, or any change whatever.

TRANSFER CERTIFICATE

In connection with any transfer of any of the Series 2017A Notes evidenced by this certificate [prior to the expiration of the Distribution Compliance Period] [2], the undersigned confirms that such Series 2017A Notes are being:

CHECK ONE BOX BELOW

(1) ☐ exchanged for the undersigned’s own account without transfer; or

(2) ☐ transferred to the Company; or

(3) ☐ transferred to a person whom the undersigned reasonably believes is a “qualified institutional buyer” within the meaning of Rule 144A under the Securities Act of 1933, as amended (the “1933 Act”), purchasing for its own account or for the account of a “qualified institutional buyer” to whom notice is given that the resale, pledge or other transfer is being made in reliance on Rule 144A under the 1933 Act; or

(4) ☐ transferred pursuant to an exemption under Rule 144 under the 1933 Act; or

(5) ☐ transferred in an offshore transaction in accordance with Rule 903 or Rule 904 of Regulation S under the 1933 Act; or

(6) ☐ transferred pursuant to another available exemption from the registration requirements of the 1933 Act; or

(7) ☐ transferred pursuant to an effective registration statement under the 1933 Act.

Unless one of the boxes is checked, the Trustee will refuse to register any of the Series 2017A Notes evidenced by this certificate in the name of any person other than the registered Holder thereof; provided, however, that if box (4) or (6) is checked, the Company may require, prior to registering any such transfer of the Series 2017A Notes, such legal opinions, certifications and other information as the Company has reasonably requested to confirm that such transfer is being made pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the 1933 Act, such as the exemption provided by Rule 144 under the 1933 Act; provided, further, that if box (3) is checked, the transferee must certify that it is a qualified institutional buyer as defined in Rule 144A.

Date: ______________________

____________________________________________
Signature

____________________________________________
Tax Identification Number

[2] [To be included for Regulation S Global Notes only.]

TO BE COMPLETED BY PURCHASER IF (3) ABOVE IS CHECKED.

The undersigned represents and warrants that it is purchasing this Series 2017A Note for its own account or an account with respect to which it exercises sole investment discretion and that it and any such account is a "qualified institutional buyer" within the meaning of Rule 144A under the 1933 Act, and is aware that the sale to it is being made in reliance on Rule 144A and acknowledges that it has received such information regarding the Company as the undersigned has requested pursuant to Rule 144A or has determined not to request such information and that it is aware that the transferor is relying upon the undersigned's foregoing representations in order to claim the exemption from registration provided by Rule 144A.

Date: ________________________

______________________________

Signature

**NOTICE: If an entity, to be executed by an executive officer.**

SCHEDULE I TO GLOBAL SECURITY

The initial amount of the Global Securities evidenced by this certificate is $_______________.

SCHEDULE OF INCREASES OR DECREASES IN GLOBAL SECURITY

The following increases or decreases in this Global Security have been made

| Date | Amount of increase in Principal Amount of this Global Security | Amount of decrease in Principal Amount of this Global Security | Principal Amount of this Global Security following each decrease or increase | Signature of authorized signatory of Trustee or Securities Registrar |
|---|---|---|---|---|

EXHIBIT B

CERTIFICATE OF AUTHENTICATION

This is one of the Senior Notes referred to in the within-mentioned Indenture.

WELLS FARGO BANK, NATIONAL
ASSOCIATION, as Trustee

Dated: By: ______________________________

Authorized Signatory

Exhibit 4(g)6

When recorded return to:

David Hight, Esq.
Ice Miller LLP
2300 Cabot Drive
Suite 455
Lisle, IL 60532

Space Above this Line Reserved for Recorder's Use Only

# SUPPLEMENTAL INDENTURE

**MADE AS OF JULY 27, 2017, TO BE EFFECTIVE AUGUST 10, 2017**

**NORTHERN ILLINOIS GAS COMPANY**

**TO**

**THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A.**

**TRUSTEE UNDER INDENTURE DATED AS OF**

**JANUARY 1, 1954**

**and**

**SUPPLEMENTAL INDENTURES THERETO**

**FIRST MORTGAGE BONDS 3.03% SERIES DUE AUGUST 10, 2027**
**FIRST MORTGAGE BONDS 3.62% SERIES DUE AUGUST 10, 2037**
**FIRST MORTGAGE BONDS 3.85% SERIES DUE AUGUST 10, 2047**
**FIRST MORTGAGE BONDS 4.00% SERIES DUE AUGUST 10, 2057**

THIS SUPPLEMENTAL INDENTURE, made as of July 27, 2017 and effective August 10, 2017, between NORTHERN ILLINOIS GAS COMPANY, a corporation organized and existing under the laws of the State of Illinois (hereinafter called the " **Company** "), and THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A. (hereinafter called the " **Trustee** "), as successor Trustee under an Indenture dated as of January 1, 1954, as modified by the Indenture of Adoption, dated February 9, 1954 and the Indenture of Release, dated February 9, 1954, and as supplemented by Supplemental Indentures dated (or made effective) April 1, 1956, June 1, 1959, July 1, 1960, June 1, 1963, July 1, 1963, August 1, 1964, August 1, 1965, May 1, 1966, August 1, 1966, July 1, 1967, June 1, 1968, December 1, 1969, August 1, 1970, June 1, 1971, July 1, 1972, July 1, 1973, April 1, 1975, April 30, 1976 (two Supplemental Indentures bearing that date), July 1, 1976, August 1, 1976, December 1, 1977, January 15, 1979, December 1, 1981, March 1, 1983, October 1, 1984, December 1, 1986, March 15, 1988, July 1, 1988, July 1, 1989, July 15, 1990, August 15, 1991, July 15, 1992, February 1, 1993, March 15, 1993, May 1, 1993, July 1, 1993, August 15, 1994, October 15, 1995, May 10, 1996, August 1, 1996, June 1, 1997, October 15, 1997, February 15, 1998, June 1, 1998, February 1, 1999, February 1, 2001, May 15, 2001, August 15, 2001, December 15, 2001, December 1, 2003 (three Supplemental Indentures bearing that date), December 15, 2006, August 15, 2008, July 30, 2009, February 1, 2011, October 26, 2012 and June 23, 2016, such Indenture dated as of January 1, 1954, as so modified and supplemented, being hereinafter called the " **Indenture** ."

WITNESSETH:

WHEREAS, the Indenture provides for the issuance from time to time thereunder, in series, of bonds of the Company for the purposes and subject to the limitations therein specified; and

WHEREAS, the Company desires, by this Supplemental Indenture, to create four additional series of bonds to be issuable under the Indenture, such bonds to be designated, respectively, (a) "First Mortgage Bonds 3.03% Series due August 10, 2027" (hereinafter called the " **2027 Series** "), (b) "First Mortgage Bonds 3.62% Series due August 10, 2037" (hereinafter called the " **2037 Series** "), (c) "First Mortgage Bonds 3.85% due August 10, 2047" (hereinafter called the " **2047 Series** "), and (d) "First Mortgage Bonds 4.00% due August 10, 2057" (hereinafter called the " **2057 Series** " the 2027 Series, the 2037 Series, the 2047 Series and the 2057 Series, hereinafter called, collectively, the " **bonds of this Supplemental Indenture** "), and the terms and provisions to be contained in the bonds of this Supplemental Indenture or to be otherwise applicable thereto to be as set forth in this Supplemental Indenture; and

WHEREAS, the forms, respectively, of the bonds of this Supplemental Indenture, and the Trustee's certificate to be endorsed on all bonds of this Supplemental Indenture, are to be substantially as follows:

[Remainder of Page Intentionally Left Blank]

(FORM OF FACE OF BOND OF 2027 SERIES)

NO. RU-2017-A-__ $________

Ill. Commerce Commission No. 6727 and 6728 CUSIP No. 665228 D@8

**NORTHERN ILLINOIS GAS COMPANY**

**First Mortgage Bond 3.03% Series due August 10, 2027**

NORTHERN ILLINOIS GAS COMPANY, an Illinois corporation (hereinafter called the " **Company** "), for value received, hereby promises to pay to or registered assigns, the sum of Dollars, on August 10, 2027, and to pay to the registered owner hereof interest on said sum from the date hereof until said sum shall be paid, at the rate of 3.03% per annum, payable semi-annually on the tenth day of February and the tenth day of August in each year, beginning on February 10, 2018. Both the principal of and the interest on this bond shall be payable at the office or agency of the Company in the City of Chicago, State of Illinois, or, at the option of the registered owner, at the office or agency of the Company in the Borough of Manhattan, The City and State of New York, in any coin or currency of the United States of America which at the time of payment is legal tender for the payment of public and private debts. Any installment of interest on this bond may, at the Company's option, be paid by mailing checks for such interest payable to or upon the written order of the person entitled thereto to the address of such person as it appears on the registration books.

So long as there is no existing default in the payment of interest on this bond, the interest so payable on any interest payment date will be paid to the person in whose name this bond is registered on January 26 or July 26 (whether or not a business day), as the case may be, next preceding such interest payment date. If and to the extent that the Company shall default in the payment of interest due on such interest payment date, such defaulted interest shall be paid to the person in whose name this bond is registered on the record date fixed, in advance, by the Company for the payment of such defaulted interest.

Additional provisions of this bond are set forth on the reverse hereof.

This bond shall not be entitled to any security or benefit under the Indenture or be valid or become obligatory for any purpose unless and until it shall have been authenticated by the execution by the Trustee, or its successor in trust under the Indenture, of the certificate endorsed hereon.

IN WITNESS WHEREOF, Northern Illinois Gas Company has caused this bond to be executed in its name by its , manually or by facsimile signature, and has caused its corporate seal to be impressed hereon or a facsimile thereof to be imprinted hereon and to be attested by its , manually or by facsimile signature.

Dated: August 10, 2017

**NORTHERN ILLINOIS GAS COMPANY**

By: ___________________________________

ATTEST:

______________________________________

(FORM OF TRUSTEE'S CERTIFICATE OF AUTHENTICATION)

This bond is one of the bonds of the 2027 Series designated therein, referred to and described in the within-mentioned Supplemental Indenture dated as of July 27, 2017, effective August 10, 2017.

**THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A.,**
**TRUSTEE**

By:________________________________________

*Authorized Officer*

Dated: August 10, 2017

(FORM OF REVERSE SIDE OF BOND OF 2027 SERIES)

This bond is one, of the series hereinafter specified, of the bonds issued and to be issued in series from time to time under and in accordance with and secured by an Indenture dated as of January 1, 1954, to The Bank of New York Mellon Trust Company, N.A., as Trustee, as supplemented by certain indentures supplemental thereto, executed and delivered to the Trustee; and this bond is one of a series of such bonds, designated "Northern Illinois Gas Company First Mortgage Bond 3.03% Series due August 10, 2027" (herein called " **bonds of this Series** "), the issuance of which is provided for by a Supplemental Indenture dated as of July 27, 2017, effective August 10, 2017 (hereinafter called the " **Supplemental Indenture** "), executed and delivered by the Company to the Trustee. The term " **Indenture** ", as hereinafter used, means said Indenture dated as of January 1, 1954, and all indentures supplemental thereto (including, without limitation, the Supplemental Indenture) from time to time in effect. Reference is made to the Indenture for a description of the property mortgaged and pledged, the nature and extent of the security, the rights of the holders and registered owners of said bonds, of the Company and of the Trustee in respect of the security, and the terms and conditions governing the issuance and security of said bonds.

Any transferee, by its acceptance of a bond registered in its name (or the name of its nominee), shall be deemed to have made the representation set forth in Section 6.2 of the Bond Purchase Agreement dated as of July 27, 2017 among the Company and the purchasers listed on Schedule A attached thereto, as amended, restated, supplemented or otherwise modified from time to time.

With the consent of the Company and to the extent permitted by and as provided in the Indenture, modifications or alterations of the Indenture or of any supplemental indenture and of the rights and obligations of the Company and of the holders and registered owners of the bonds may be made, and compliance with any provision of the Indenture or of any supplemental indenture may be waived, by the affirmative vote of the holders and registered owners of not less than sixty-six and two-thirds per centum (66 2/3%) in principal amount of the bonds then outstanding under the Indenture, and by the affirmative vote of the holders and registered owners of not less than sixty-six and two-thirds per centum (66 2/3%) in principal amount of the bonds of any series then outstanding under the Indenture and affected by such modification or alteration, in case one or more but less than all of the series of bonds then outstanding under the Indenture are so affected, but in any case excluding bonds disqualified from voting by reason of the Company's interest therein as provided in the Indenture; subject, however, to the condition, among other conditions stated in the Indenture, that no such modification or alteration shall be made which, among other things, will permit the extension of the time or times of payment of the principal of or the interest or the premium, if any, on this bond, or the reduction in the principal amount hereof or in the rate of interest or the amount of any premium hereon, or any other modification in the terms of payment of such principal, interest or premium, which terms of payment are unconditional, or, otherwise than as permitted by the Indenture, the creation of any lien ranking prior to or on a parity with the lien of the Indenture with respect to any of the mortgaged property, all as more fully provided in the Indenture.

The bonds of this Series may be called for redemption by the Company, as a whole at any time or in part from time to time, at a redemption price equal to 100% of the principal amount of the bonds of this Series to be redeemed plus accrued and unpaid interest on the principal amount being redeemed to the date of redemption and the Make-Whole Amount (as defined in the Supplemental Indenture) applicable thereto.

Notice of each redemption shall be mailed to all registered owners not less than thirty nor more than forty-five days before the redemption date.

In case of certain completed defaults specified in the Indenture, the principal of this bond may be declared or may become due and payable in the manner and with the effect provided in the Indenture.

No recourse shall be had for the payment of the principal of or the interest or the premium, if any, on this bond, or for any claim based hereon, or otherwise in respect hereof or of the Indenture, to or against any incorporator, stockholder, officer or director, past, present or future, of the Company or of any predecessor or successor corporation, either directly or through the Company or such predecessor or successor corporation, under any constitution or statute or rule of law, or by the enforcement of any assessment or penalty, or otherwise, all such liability of incorporators, stockholders, directors and officers being waived and released by the registered owner hereof by the acceptance of this bond and being likewise waived and released by the terms of the Indenture, all as more fully provided therein.

This bond is transferable by the registered owner hereof, in person or by duly authorized attorney, at the office or agency of the Company in the City of Chicago, State of Illinois, or, at the option of registered owner, at the office or agency of the Company in the Borough of Manhattan, The City and State of New York, upon surrender and cancellation of this bond; and thereupon a new registered bond or bonds without coupons of the same aggregate principal amount and series will, upon the payment of any transfer tax or taxes payable, be issued to the transferee in exchange herefor. The Company shall not be required to exchange or transfer this bond if this bond or a portion hereof has been selected for redemption.

The security represented by this certificate has not been registered under the Securities Act of 1933, as amended (the " **Securities Act** "), or qualified under any state securities laws and may not be transferred, sold or otherwise disposed of except while a registration statement is in effect or pursuant to an available exemption from registration under the Securities Act and applicable state securities laws.

(END OF FORM OF BOND OF 2027 SERIES)

(FORM OF FACE OF BOND OF 2037 SERIES)

NO. RU-2017-B-__ $________

Ill. Commerce Commission No. 6727 and 6728 CUSIP No. 665228 D#6

**NORTHERN ILLINOIS GAS COMPANY**

**First Mortgage Bond 3.62% Series due August 10, 2037**

NORTHERN ILLINOIS GAS COMPANY, an Illinois corporation (hereinafter called the " **Company** "), for value received, hereby promises to pay to or registered assigns, the sum of Dollars, on August 10, 2037, and to pay to the registered owner hereof interest on said sum from the date hereof until said sum shall be paid, at the rate of 3.62% per annum, payable semi-annually on the tenth day of February and the tenth day of August in each year, beginning on February 10, 2018. Both the principal of and the interest on this bond shall be payable at the office or agency of the Company in the City of Chicago, State of Illinois, or, at the option of the registered owner, at the office or agency of the Company in the Borough of Manhattan, The City and State of New York, in any coin or currency of the United States of America which at the time of payment is legal tender for the payment of public and private debts. Any installment of interest on this bond may, at the Company's option, be paid by mailing checks for such interest payable to or upon the written order of the person entitled thereto to the address of such person as it appears on the registration books.

So long as there is no existing default in the payment of interest on this bond, the interest so payable on any interest payment date will be paid to the person in whose name this bond is registered on January 26 or July 26 (whether or not a business day), as the case may be, next preceding such interest payment date. If and to the extent that the Company shall default in the payment of interest due on such interest payment date, such defaulted interest shall be paid to the person in whose name this bond is registered on the record date fixed, in advance, by the Company for the payment of such defaulted interest.

Additional provisions of this bond are set forth on the reverse hereof.

This bond shall not be entitled to any security or benefit under the Indenture or be valid or become obligatory for any purpose unless and until it shall have been authenticated by the execution by the Trustee, or its successor in trust under the Indenture, of the certificate endorsed hereon.

IN WITNESS WHEREOF, Northern Illinois Gas Company has caused this bond to be executed in its name by its , manually or by facsimile signature, and has caused its corporate seal to be impressed hereon or a facsimile thereof to be imprinted hereon and to be attested by its , manually or by facsimile signature.

Dated: August 10, 2017

**NORTHERN ILLINOIS GAS COMPANY**

By:

____________________________________

ATTEST:

____________________________________

(FORM OF TRUSTEE'S CERTIFICATE OF AUTHENTICATION)

This bond is one of the bonds of the 2037 Series designated therein, referred to and described in the within-mentioned Supplemental Indenture dated as of July 27, 2017, effective August 10, 2017.

**THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A.,**
**TRUSTEE**

By:________________________________________
*Authorized Officer*

Dated: August 10, 2017

(FORM OF REVERSE SIDE OF BOND OF 2037 SERIES)

This bond is one, of the series hereinafter specified, of the bonds issued and to be issued in series from time to time under and in accordance with and secured by an Indenture dated as of January 1, 1954, to The Bank of New York Mellon Trust Company, N.A., as Trustee, as supplemented by certain indentures supplemental thereto, executed and delivered to the Trustee; and this bond is one of a series of such bonds, designated “Northern Illinois Gas Company First Mortgage Bond 3.62% Series due August 10, 2037” (herein called “ **bonds of this Series** ”), the issuance of which is provided for by a Supplemental Indenture dated as of July 27, 2017, effective August 10, 2017 (hereinafter called the “ **Supplemental Indenture** ”), executed and delivered by the Company to the Trustee. The term “ **Indenture** ”, as hereinafter used, means said Indenture dated as of January 1, 1954, and all indentures supplemental thereto (including, without limitation, the Supplemental Indenture) from time to time in effect. Reference is made to the Indenture for a description of the property mortgaged and pledged, the nature and extent of the security, the rights of the holders and registered owners of said bonds, of the Company and of the Trustee in respect of the security, and the terms and conditions governing the issuance and security of said bonds.

Any transferee, by its acceptance of a bond registered in its name (or the name of its nominee), shall be deemed to have made the representation set forth in Section 6.2 of the Bond Purchase Agreement dated as of July 27, 2017 among the Company and the purchasers listed on Schedule A attached thereto, as amended, restated, supplemented or otherwise modified from time to time.

With the consent of the Company and to the extent permitted by and as provided in the Indenture, modifications or alterations of the Indenture or of any supplemental indenture and of the rights and obligations of the Company and of the holders and registered owners of the bonds may be made, and compliance with any provision of the Indenture or of any supplemental indenture may be waived, by the affirmative vote of the holders and registered owners of not less than sixty-six and two-thirds per centum (66 2/3%) in principal amount of the bonds then outstanding under the Indenture, and by the affirmative vote of the holders and registered owners of not less than sixty-six and two-thirds per centum (66 2/3%) in principal amount of the bonds of any series then outstanding under the Indenture and affected by such modification or alteration, in case one or more but less than all of the series of bonds then outstanding under the Indenture are so affected, but in any case excluding bonds disqualified from voting by reason of the Company’s interest therein as provided in the Indenture; subject, however, to the condition, among other conditions stated in the Indenture, that no such modification or alteration shall be made which, among other things, will permit the extension of the time or times of payment of the principal of or the interest or the premium, if any, on this bond, or the reduction in the principal amount hereof or in the rate of interest or the amount of any premium hereon, or any other modification in the terms of payment of such principal, interest or premium, which terms of payment are unconditional, or, otherwise than as permitted by the Indenture, the creation of any lien ranking prior to or on a parity with the lien of the Indenture with respect to any of the mortgaged property, all as more fully provided in the Indenture.

The bonds of this Series may be called for redemption by the Company, as a whole at any time or in part from time to time, at a redemption price equal to 100% of the principal amount of the bonds of this Series to be redeemed plus accrued and unpaid interest on the principal amount being redeemed to the date of redemption and the Make-Whole Amount (as defined in the Supplemental Indenture) applicable thereto.

Notice of each redemption shall be mailed to all registered owners not less than thirty nor more than forty-five days before the redemption date.

In case of certain completed defaults specified in the Indenture, the principal of this bond may be declared or may become due and payable in the manner and with the effect provided in the Indenture.

No recourse shall be had for the payment of the principal of or the interest or the premium, if any, on this bond, or for any claim based hereon, or otherwise in respect hereof or of the Indenture, to or against any incorporator, stockholder, officer or director, past, present or future, of the Company or of any predecessor or successor corporation, either directly or through the Company or such predecessor or successor corporation, under any constitution or statute or rule of law, or by the enforcement of any assessment or penalty, or otherwise, all such liability of incorporators, stockholders, directors and officers being waived and released by the registered owner hereof by the acceptance of this bond and being likewise waived and released by the terms of the Indenture, all as more fully provided therein.

This bond is transferable by the registered owner hereof, in person or by duly authorized attorney, at the office or agency of the Company in the City of Chicago, State of Illinois, or, at the option of registered owner, at the office or agency of the Company in the Borough of Manhattan, The City and State of New York, upon surrender and cancellation of this bond; and thereupon a new registered bond or bonds without coupons of the same aggregate principal amount and series will, upon the payment of any transfer tax or taxes payable, be issued to the transferee in exchange herefor. The Company shall not be required to exchange or transfer this bond if this bond or a portion hereof has been selected for redemption.

The security represented by this certificate has not been registered under the Securities Act of 1933, as amended (the " **Securities Act** "), or qualified under any state securities laws and may not be transferred, sold or otherwise disposed of except while a registration statement is in effect or pursuant to an available exemption from registration under the Securities Act and applicable state securities laws.

(END OF FORM OF BOND OF 2037 SERIES)

(FORM OF FACE OF BOND OF 2047 SERIES)

NO. RU-2017-C-__ $________

Ill. Commerce Commission No. 6727 and 6728 CUSIP No. 665228 E*9

**NORTHERN ILLINOIS GAS COMPANY**

**First Mortgage Bond 3.85% Series due August 10, 2047**

NORTHERN ILLINOIS GAS COMPANY, an Illinois corporation (hereinafter called the " **Company** "), for value received, hereby promises to pay to or registered assigns, the sum of Dollars, on August 10, 2047, and to pay to the registered owner hereof interest on said sum from the date hereof until said sum shall be paid, at the rate of 3.85% per annum, payable semi-annually on the tenth day of February and the tenth day of August in each year, beginning on February 10, 2018. Both the principal of and the interest on this bond shall be payable at the office or agency of the Company in the City of Chicago, State of Illinois, or, at the option of the registered owner, at the office or agency of the Company in the Borough of Manhattan, The City and State of New York, in any coin or currency of the United States of America which at the time of payment is legal tender for the payment of public and private debts. Any installment of interest on this bond may, at the Company's option, be paid by mailing checks for such interest payable to or upon the written order of the person entitled thereto to the address of such person as it appears on the registration books.

So long as there is no existing default in the payment of interest on this bond, the interest so payable on any interest payment date will be paid to the person in whose name this bond is registered on January 26 or July 26 (whether or not a business day), as the case may be, next preceding such interest payment date. If and to the extent that the Company shall default in the payment of interest due on such interest payment date, such defaulted interest shall be paid to the person in whose name this bond is registered on the record date fixed, in advance, by the Company for the payment of such defaulted interest.

Additional provisions of this bond are set forth on the reverse hereof.

This bond shall not be entitled to any security or benefit under the Indenture or be valid or become obligatory for any purpose unless and until it shall have been authenticated by the execution by the Trustee, or its successor in trust under the Indenture, of the certificate endorsed hereon.

IN WITNESS WHEREOF, Northern Illinois Gas Company has caused this bond to be executed in its name by its , manually or by facsimile signature, and has caused its corporate seal to be impressed hereon or a facsimile thereof to be imprinted hereon and to be attested by its , manually or by facsimile signature.

Dated: November 1, 2017

**NORTHERN ILLINOIS GAS COMPANY**

By: _______________________________________

ATTEST:

_______________________________________

(FORM OF TRUSTEE'S CERTIFICATE OF AUTHENTICATION)

This bond is one of the bonds of the 2047 Series designated therein, referred to and described in the within-mentioned Supplemental Indenture dated as of July 27, 2017, effective August 10, 2017.

**THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A.,**
**TRUSTEE**

By:________________________________________
*Authorized Officer*

Dated: November 1, 2017

(FORM OF REVERSE SIDE OF BOND OF 2047 SERIES)

This bond is one, of the series hereinafter specified, of the bonds issued and to be issued in series from time to time under and in accordance with and secured by an Indenture dated as of January 1, 1954, to The Bank of New York Mellon Trust Company, N.A., as Trustee, as supplemented by certain indentures supplemental thereto, executed and delivered to the Trustee; and this bond is one of a series of such bonds, designated "Northern Illinois Gas Company First Mortgage Bond 3.85% Series due August 10, 2047" (herein called " **bonds of this Series** "), the issuance of which is provided for by a Supplemental Indenture dated as of July 27, 2017, effective August 10, 2017 (hereinafter called the " **Supplemental Indenture** "), executed and delivered by the Company to the Trustee. The term " **Indenture** ", as hereinafter used, means said Indenture dated as of January 1, 1954, and all indentures supplemental thereto (including, without limitation, the Supplemental Indenture) from time to time in effect. Reference is made to the Indenture for a description of the property mortgaged and pledged, the nature and extent of the security, the rights of the holders and registered owners of said bonds, of the Company and of the Trustee in respect of the security, and the terms and conditions governing the issuance and security of said bonds.

Any transferee, by its acceptance of a bond registered in its name (or the name of its nominee), shall be deemed to have made the representation set forth in Section 6.2 of the Bond Purchase Agreement dated as of July 27, 2017 among the Company and the purchasers listed on Schedule A attached thereto, as amended, restated, supplemented or otherwise modified from time to time.

With the consent of the Company and to the extent permitted by and as provided in the Indenture, modifications or alterations of the Indenture or of any supplemental indenture and of the rights and obligations of the Company and of the holders and registered owners of the bonds may be made, and compliance with any provision of the Indenture or of any supplemental indenture may be waived, by the affirmative vote of the holders and registered owners of not less than sixty-six and two-thirds per centum (66 2/3%) in principal amount of the bonds then outstanding under the Indenture, and by the affirmative vote of the holders and registered owners of not less than sixty-six and two-thirds per centum (66 2/3%) in principal amount of the bonds of any series then outstanding under the Indenture and affected by such modification or alteration, in case one or more but less than all of the series of bonds then outstanding under the Indenture are so affected, but in any case excluding bonds disqualified from voting by reason of the Company's interest therein as provided in the Indenture; subject, however, to the condition, among other conditions stated in the Indenture, that no such modification or alteration shall be made which, among other things, will permit the extension of the time or times of payment of the principal of or the interest or the premium, if any, on this bond, or the reduction in the principal amount hereof or in the rate of interest or the amount of any premium hereon, or any other modification in the terms of payment of such principal, interest or premium, which terms of payment are unconditional, or, otherwise than as permitted by the Indenture, the creation of any lien ranking prior to or on a parity with the lien of the Indenture with respect to any of the mortgaged property, all as more fully provided in the Indenture.

The bonds of this Series may be called for redemption by the Company, as a whole at any time or in part from time to time, at a redemption price equal to 100% of the principal amount of the bonds of this Series to be redeemed plus accrued and unpaid interest on the principal amount being redeemed to the date of redemption and the Make-Whole Amount (as defined in the Supplemental Indenture) applicable thereto.

Notice of each redemption shall be mailed to all registered owners not less than thirty nor more than forty-five days before the redemption date.

In case of certain completed defaults specified in the Indenture, the principal of this bond may be declared or may become due and payable in the manner and with the effect provided in the Indenture.

No recourse shall be had for the payment of the principal of or the interest or the premium, if any, on this bond, or for any claim based hereon, or otherwise in respect hereof or of the Indenture, to or against any incorporator, stockholder, officer or director, past, present or future, of the Company or of any predecessor or successor corporation, either directly or through the Company or such predecessor or successor corporation, under any constitution or statute or rule of law, or by the enforcement of any assessment or penalty, or otherwise, all such liability of incorporators, stockholders, directors and officers being waived and released by the registered owner hereof by the acceptance of this bond and being likewise waived and released by the terms of the Indenture, all as more fully provided therein.

This bond is transferable by the registered owner hereof, in person or by duly authorized attorney, at the office or agency of the Company in the City of Chicago, State of Illinois, or, at the option of registered owner, at the office or agency of the Company in the Borough of Manhattan, The City and State of New York, upon surrender and cancellation of this bond; and thereupon a new registered bond or bonds without coupons of the same aggregate principal amount and series will, upon the payment of any transfer tax or taxes payable, be issued to the transferee in exchange herefor. The Company shall not be required to exchange or transfer this bond if this bond or a portion hereof has been selected for redemption.

The security represented by this certificate has not been registered under the Securities Act of 1933, as amended (the " **Securities Act** "), or qualified under any state securities laws and may not be transferred, sold or otherwise disposed of except while a registration statement is in effect or pursuant to an available exemption from registration under the Securities Act and applicable state securities laws.

(END OF FORM OF BOND OF 2047 SERIES)

(FORM OF FACE OF BOND OF 2057 SERIES)

NO. RU-2017-D-__ $________

Ill. Commerce Commission No. 6727 and 6728 CUSIP No. 665228 E@7

**NORTHERN ILLINOIS GAS COMPANY**

**First Mortgage Bond 4.00% Series due August 10, 2057**

NORTHERN ILLINOIS GAS COMPANY, an Illinois corporation (hereinafter called the " **Company** "), for value received, hereby promises to pay to or registered assigns, the sum of Dollars, on August 10, 2057, and to pay to the registered owner hereof interest on said sum from the date hereof until said sum shall be paid, at the rate of 4.00% per annum, payable semi-annually on the tenth day of February and the tenth day of August in each year, beginning on February 10, 2018. Both the principal of and the interest on this bond shall be payable at the office or agency of the Company in the City of Chicago, State of Illinois, or, at the option of the registered owner, at the office or agency of the Company in the Borough of Manhattan, The City and State of New York, in any coin or currency of the United States of America which at the time of payment is legal tender for the payment of public and private debts. Any installment of interest on this bond may, at the Company's option, be paid by mailing checks for such interest payable to or upon the written order of the person entitled thereto to the address of such person as it appears on the registration books.

So long as there is no existing default in the payment of interest on this bond, the interest so payable on any interest payment date will be paid to the person in whose name this bond is registered on January 26 or July 26 (whether or not a business day), as the case may be, next preceding such interest payment date. If and to the extent that the Company shall default in the payment of interest due on such interest payment date, such defaulted interest shall be paid to the person in whose name this bond is registered on the record date fixed, in advance, by the Company for the payment of such defaulted interest.

Additional provisions of this bond are set forth on the reverse hereof.

This bond shall not be entitled to any security or benefit under the Indenture or be valid or become obligatory for any purpose unless and until it shall have been authenticated by the execution by the Trustee, or its successor in trust under the Indenture, of the certificate endorsed hereon.

IN WITNESS WHEREOF, Northern Illinois Gas Company has caused this bond to be executed in its name by its , manually or by facsimile signature, and has caused its corporate seal to be impressed hereon or a facsimile thereof to be imprinted hereon and to be attested by its , manually or by facsimile signature.

Dated: November 1, 2017

**NORTHERN ILLINOIS GAS COMPANY**

By: ________________________________

ATTEST:

________________________________

(FORM OF TRUSTEE'S CERTIFICATE OF AUTHENTICATION)

This bond is one of the bonds of the 2057 Series designated therein, referred to and described in the within-mentioned Supplemental Indenture dated as of July 27, 2017, effective August 10, 2017.

**THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A.,**
**TRUSTEE**

By:________________________________________
*Authorized Officer*

Dated: November 1, 2017

(FORM OF REVERSE SIDE OF BOND OF 2057 SERIES)

This bond is one, of the series hereinafter specified, of the bonds issued and to be issued in series from time to time under and in accordance with and secured by an Indenture dated as of January 1, 1954, to The Bank of New York Mellon Trust Company, N.A., as Trustee, as supplemented by certain indentures supplemental thereto, executed and delivered to the Trustee; and this bond is one of a series of such bonds, designated “Northern Illinois Gas Company First Mortgage Bond 4.00% Series due August 10, 2057” (herein called “ **bonds of this Series** ”), the issuance of which is provided for by a Supplemental Indenture dated as of July 27, 2017, effective August 10, 2017 (hereinafter called the “ **Supplemental Indenture** ”), executed and delivered by the Company to the Trustee. The term “ **Indenture** ”, as hereinafter used, means said Indenture dated as of January 1, 1954, and all indentures supplemental thereto (including, without limitation, the Supplemental Indenture) from time to time in effect. Reference is made to the Indenture for a description of the property mortgaged and pledged, the nature and extent of the security, the rights of the holders and registered owners of said bonds, of the Company and of the Trustee in respect of the security, and the terms and conditions governing the issuance and security of said bonds.

Any transferee, by its acceptance of a bond registered in its name (or the name of its nominee), shall be deemed to have made the representation set forth in Section 6.2 of the Bond Purchase Agreement dated as of July 27, 2017 among the Company and the purchasers listed on Schedule A attached thereto, as amended, restated, supplemented or otherwise modified from time to time.

With the consent of the Company and to the extent permitted by and as provided in the Indenture, modifications or alterations of the Indenture or of any supplemental indenture and of the rights and obligations of the Company and of the holders and registered owners of the bonds may be made, and compliance with any provision of the Indenture or of any supplemental indenture may be waived, by the affirmative vote of the holders and registered owners of not less than sixty-six and two-thirds per centum (66 2/3%) in principal amount of the bonds then outstanding under the Indenture, and by the affirmative vote of the holders and registered owners of not less than sixty-six and two-thirds per centum (66 2/3%) in principal amount of the bonds of any series then outstanding under the Indenture and affected by such modification or alteration, in case one or more but less than all of the series of bonds then outstanding under the Indenture are so affected, but in any case excluding bonds disqualified from voting by reason of the Company’s interest therein as provided in the Indenture; subject, however, to the condition, among other conditions stated in the Indenture, that no such modification or alteration shall be made which, among other things, will permit the extension of the time or times of payment of the principal of or the interest or the premium, if any, on this bond, or the reduction in the principal amount hereof or in the rate of interest or the amount of any premium hereon, or any other modification in the terms of payment of such principal, interest or premium, which terms of payment are unconditional, or, otherwise than as permitted by the Indenture, the creation of any lien ranking prior to or on a parity with the lien of the Indenture with respect to any of the mortgaged property, all as more fully provided in the Indenture.

The bonds of this Series may be called for redemption by the Company, as a whole at any time or in part from time to time, at a redemption price equal to 100% of the principal amount of the bonds of this Series to be redeemed plus accrued and unpaid interest on the principal amount being redeemed to the date of redemption and the Make-Whole Amount (as defined in the Supplemental Indenture) applicable thereto.

Notice of each redemption shall be mailed to all registered owners not less than thirty nor more than forty-five days before the redemption date.

In case of certain completed defaults specified in the Indenture, the principal of this bond may be declared or may become due and payable in the manner and with the effect provided in the Indenture.

No recourse shall be had for the payment of the principal of or the interest or the premium, if any, on this bond, or for any claim based hereon, or otherwise in respect hereof or of the Indenture, to or against any incorporator, stockholder, officer or director, past, present or future, of the Company or of any predecessor or successor corporation, either directly or through the Company or such predecessor or successor corporation, under any constitution or statute or rule of law, or by the enforcement of any assessment or penalty, or otherwise, all such liability of incorporators, stockholders, directors and officers being waived and released by the registered owner hereof by the acceptance of this bond and being likewise waived and released by the terms of the Indenture, all as more fully provided therein.

This bond is transferable by the registered owner hereof, in person or by duly authorized attorney, at the office or agency of the Company in the City of Chicago, State of Illinois, or, at the option of registered owner, at the office or agency of the Company in the Borough of Manhattan, The City and State of New York, upon surrender and cancellation of this bond; and thereupon a new registered bond or bonds without coupons of the same aggregate principal amount and series will, upon the payment of any transfer tax or taxes payable, be issued to the transferee in exchange herefor. The Company shall not be required to exchange or transfer this bond if this bond or a portion hereof has been selected for redemption.

The security represented by this certificate has not been registered under the Securities Act of 1933, as amended (the " **Securities Act** "), or qualified under any state securities laws and may not be transferred, sold or otherwise disposed of except while a registration statement is in effect or pursuant to an available exemption from registration under the Securities Act and applicable state securities laws.

(END OF FORM OF BOND OF 2057 SERIES)

and

WHEREAS, all acts and things necessary to make this Supplemental Indenture, when duly executed and delivered, a valid, binding and legal instrument in accordance with its terms, and for the purposes herein expressed, have been done and performed, and the execution and delivery of this Supplemental Indenture have in all respects been duly authorized;

NOW THEREFORE, in consideration of the premises and of the sum of one dollar paid by the Trustee to the Company, and for other good and valuable consideration, the receipt of which is hereby acknowledged, for the purpose of securing the due and punctual payment of the principal of and the interest and premium, if any, on all bonds which shall be issued under the Indenture, and for the purpose of securing the faithful performance and observance of all the covenants and conditions set forth in the Indenture and in all indentures supplemental thereto, the Company by these presents does grant, bargain, sell, transfer, assign, pledge, mortgage, warrant and convey unto The Bank of New York Mellon Trust Company, N.A., as Trustee, and its successor or successors in the trust hereby created, all property, real and personal (other than property expressly excepted from the lien and operation of the Indenture), which, at the actual date of execution and delivery of this Supplemental Indenture, is solely used or held for use in the operation by the Company of its gas utility system and in the conduct of its gas utility business and all property, real and personal, used or useful in the gas utility business (other than property expressly excepted from the lien and operation of the Indenture) acquired by the Company after the actual date of execution and delivery of this Supplemental Indenture or (subject to the provisions of Section 16.03 of the Indenture) by any successor corporation after such execution and delivery, and it is further agreed by and between the Company and the Trustee as follows:

## ARTICLE I

## BONDS OF THIS SUPPLEMENTAL INDENTURE

Section 1. The bonds of this Supplemental Indenture shall, as hereinbefore recited, be designated as the Company's (a) "First Mortgage Bonds 3.03% Series due August 10, 2027", (b) "First Mortgage Bonds 3.62% Series due August 10, 2037", (c) "First Mortgage Bonds 3.85% Series due August 10, 2047", and (d) "First Mortgage Bonds 4.00% Series due August 10, 2057", as applicable. The bonds of the 2027 Series which may be issued and outstanding shall not exceed $100,000,000 in aggregate principal amount, exclusive of bonds of such series authenticated and delivered pursuant to Section 4.12 of the Indenture. The bonds of the 2037 Series which may be issued and outstanding shall not exceed $100,000,000 in aggregate principal amount, exclusive of bonds of such series authenticated and delivered pursuant to Section 4.12 of the Indenture. The bonds of the 2047 Series which may be issued and outstanding shall not exceed $100,000,000 in aggregate principal amount, exclusive of bonds of such series authenticated and delivered pursuant to Section 4.12 of the Indenture. The bonds of the 2057 Series which may be issued and outstanding shall not exceed $100,000,000 in aggregate principal amount, exclusive of bonds of such series authenticated and delivered pursuant to Section 4.12 of the Indenture.

Section 2. The bonds of this Supplemental Indenture shall be registered bonds without coupons, and the form of each series of such bonds, and of the Trustee's certificate of authentication to be endorsed on all bonds of this Supplemental Indenture, shall be substantially as hereinbefore recited, respectively.

Section 3. The bonds of this Supplemental Indenture shall be issued in the denomination of $500,000 each and in such integral multiple or multiples thereof as shall be determined and authorized by the Board of Directors of the Company or by any officer of the Company authorized by the Board of Directors to make such determination, the authorization of the denomination of any bond to be conclusively evidenced by the execution thereof on behalf of the Company. The bonds of the 2027 Series shall be numbered RU-2017-A-1 and consecutively upwards, or in such other appropriate manner as shall be determined and authorized by the Board of Directors of the Company. The bonds of the 2037 Series shall be numbered RU-2017-B-1 and consecutively upwards, or in such other appropriate manner as shall be determined and authorized by the Board of Directors of the Company. The bonds of the 2047 Series shall be numbered RU-2017-C-1 and consecutively upwards, or in such other appropriate manner as shall be determined and authorized by the Board of Directors of the Company. The bonds of the 2057 Series shall be numbered RU-2017-D-1 and consecutively upwards, or in such other appropriate manner as shall be determined and authorized by the Board of Directors of the Company.

The bonds of the 2027 Series and the 2037 Series shall be dated August 10, 2017, except that each bond issued on or after the first payment of interest thereon shall be dated as of the date of the interest payment date thereof to which interest shall have been paid on the bonds of its series next preceding the date of issue, unless issued on an interest payment date to which interest shall have been so paid, in which event such bonds shall be dated as of the date of issue; *provided* , *however* , that bonds issued on or after January 26 and before the next succeeding February 10 or on or after July 26 and before the next succeeding August 10 shall be dated the next succeeding interest payment date if interest shall have been paid to such date. The bonds of the 2047 Series and the 2057 Series shall be dated November 1, 2017, except that each bond issued on or after the respective first payment of interest thereon shall be dated as of the date of the interest payment date thereof to which interest shall have been paid on the bonds of such series next preceding the date of issue, unless issued on an interest payment date to which interest shall have been so paid, in which event such bonds shall be dated as of the date of issue; *provided* , *however* , that bonds issued on or after January 26 and before the next succeeding February 10 or on or after July 26 and before the next succeeding August 10 shall be dated the next succeeding interest payment date if interest shall have been paid to such date. The bonds of the 2027 Series shall mature on August 10, 2027 and shall bear interest at the rate of 3.03% per annum until the principal thereof shall be paid. The bonds of the 2037 Series shall mature on August 10, 2037 and shall bear interest at the rate of 3.62% per annum until the principal thereof shall be paid. The bonds of the 2047 Series shall mature on August 10, 2047 and shall bear interest at the rate of 3.85% per annum until the principal thereof shall be paid. The bonds of the 2057 Series shall mature on August 10, 2057 and shall bear interest at the rate of 4.00% per annum until the principal thereof shall be paid. Interest on the bonds of this Supplemental Indenture shall be calculated on the basis of a 360-day year consisting of twelve 30-day months. Interest on the bonds of the 2027 Series shall be payable semi-annually on the tenth day of February and the tenth day of August in each year, beginning February 10, 2018. Interest on the bonds of the 2037 Series shall be payable semi-annually on the tenth day of February and the tenth day of August in each year, beginning February 10, 2018. Interest on the bonds of the 2047 Series shall be payable semi-annually on the tenth day of February and the tenth day of August in each year, beginning February 10, 2018. Interest on the bonds of the 2057 Series shall be payable semi-annually on the tenth day of February and the tenth day of August in each year, beginning February 10, 2018. So long as there is no existing default in the payment of interest on the bonds of this Supplemental Indenture, such interest shall be payable to the person in whose name each such bond is registered on the respective record date (whether or not a business day), as the case may be, next preceding the respective interest payment dates; *provided* , *however* , if and to the extent that the Company shall default in the payment of interest due on such interest payment date, such defaulted interest shall be paid to the person in whose name each such bond is registered on the record date fixed, in advance, by the Company for the payment of such defaulted interest. Interest will accrue on overdue interest installments at the rate of (i) 3.03% per annum, with respect to the bonds of the 2027 Series, (ii) 3.62% per annum, with respect to the bonds of the 2037 Series, (iii) 3.85% per annum, with respect to the bonds of the 2047 Series, and (iv) 4.00% per annum, with respect to the bonds of the 2057 Series.

The principal of and interest and premium, if any, on the bonds of this Supplemental Indenture shall be payable in any coin or currency of the United States of America which at the time of payment is legal tender for the payment of public and private debts, and shall be payable at the office or agency of the Company in the City of Chicago, State of Illinois, or, at the option of the registered owner, at the office or agency of the Company in the Borough of Manhattan, The City and State of New York. Any installment of interest on the bonds of this Supplemental Indenture may, at the Company’s option, be paid by mailing checks for such interest payable to or upon the written order of the person entitled thereto to the address of such person as it appears on the registration books. The bonds of this Supplemental Indenture shall be registrable, transferable and exchangeable in the manner provided in Sections 4.08 and 4.09 of the Indenture, at either of such offices or agencies.

**Section 4.** The bonds of this Supplemental Indenture, upon the mailing of notice and in the manner provided in Section 7.01 of the Indenture (except that no published notice shall be required for the bonds of this Supplemental Indenture) and with the effect provided in Section 7.02 thereof, shall be redeemable at the option of the Company, as a whole at any time or in part from time to time, at a redemption price equal to 100% of the principal amount of the bonds of this Supplemental Indenture to be redeemed plus accrued and unpaid interest of the principal amount being redeemed to the date of redemption plus the Make-Whole Amount applicable thereto. **“Make-Whole Amount”** means, with respect to any bond of this Supplemental Indenture, an amount equal to the excess, if any, of the Discounted Value of the Remaining Scheduled Payments with respect to the Called Principal of such bond of this Supplemental Indenture over the amount of such Called Principal, *provided* that the Make-Whole Amount may in no event be less than zero. For the purposes of determining the Make-Whole Amount, the following terms have the following meanings:

**“Called Principal”** means, with respect to any bond of this Supplemental Indenture, the principal of such bond of this Supplemental Indenture that is to be redeemed.

**“Discounted Value”** means, with respect to the Called Principal of any bond of this Supplemental Indenture, the amount obtained by discounting all Remaining Scheduled Payments with respect to such Called Principal from their respective scheduled due dates to the Settlement Date with respect to such Called Principal, in accordance with accepted financial practice and at a discount factor (applied on the same periodic basis as that on which interest on the bond of this Supplemental Indenture is payable) equal to the Reinvestment Yield with respect to such Called Principal.

**"Reinvestment Yield"** means, with respect to the Called Principal of any bond of this Supplemental Indenture, the sum of (x) 0.50% plus (y) the yield to maturity implied by the "Ask Yield(s)" reported as of 10:00 a.m. (New York City time) on the second Business Day preceding the Settlement Date with respect to such Called Principal, on the display designated as "Page PX1" (or such other display as may replace Page PX1) on Bloomberg Financial Markets for the most recently issued actively traded on-the-run U.S. Treasury securities (" **Reported** ") having a maturity equal to the Remaining Average Life of such Called Principal as of such Settlement Date. If there are no such U.S. Treasury securities Reported having a maturity equal to such Remaining Average Life, then such implied yield to maturity will be determined by (a) converting U.S. Treasury bill quotations to bond equivalent yields in accordance with accepted financial practice and (b) interpolating linearly between the "Ask Yields" Reported for the applicable most recently issued actively traded on-the-run U.S. Treasury securities with the maturities (1) closest to and greater than such Remaining Average Life and (2) closest to and less than such Remaining Average Life. The Reinvestment Yield shall be rounded to the number of decimal places as appears in the interest rate of the applicable bond.

If such yields are not Reported or the yields Reported as of such time are not ascertainable (including by way of interpolation), then "Reinvestment Yield" means, with respect to the Called Principal of any bond of this Supplemental Indenture, the sum of (x) 0.50% plus (y) the yield to maturity implied by the U.S. Treasury constant maturity yields reported, for the latest day for which such yields have been so reported as of the second Business Day preceding the Settlement Date with respect to such Called Principal, in Federal Reserve Statistical Release H.15 (or any comparable successor publication) for the U.S. Treasury constant maturity having a term equal to the Remaining Average Life of such Called Principal as of such Settlement Date. If there is no such U.S. Treasury constant maturity having a term equal to such Remaining Average Life, such implied yield to maturity will be determined by interpolating linearly between (1) the U.S. Treasury constant maturity so reported with the term closest to and greater than such Remaining Average Life and (2) the U.S. Treasury constant maturity so reported with the term closest to and less than such Remaining Average Life. The Reinvestment Yield shall be rounded to the number of decimal places as appears in the interest rate of the applicable bond.

**"Remaining Average Life"** means, with respect to any Called Principal, the number of years obtained by dividing (a) such Called Principal into (b) the sum of the products obtained by multiplying (1) the principal component of each Remaining Scheduled Payment with respect to such Called Principal by (2) the number of years, computed on the basis of a 360-day year comprised of twelve 30-day months and calculated to the nearest two decimal places, that will elapse between the Settlement Date with respect to such Called Principal and the scheduled due date of such Remaining Scheduled Payment.

**"Remaining Scheduled Payments"** means, with respect to the Called Principal of any bond of this Supplemental Indenture, all payments of such Called Principal and interest thereon that would be due after the Settlement Date with respect to such Called Principal if no payment of such Called Principal were made prior to its scheduled due date, *provided* that if such Settlement Date is not a date on which interest payments are due to be made under the terms of the bond of this Supplemental Indenture, then the amount of the next succeeding scheduled interest payment will be reduced by the amount of interest accrued to such Settlement Date and required to be paid on such Settlement Date pursuant to the terms of this Supplemental Indenture.

**"Settlement Date"** means, with respect to the Called Principal of any bond of this Supplemental Indenture, the date on which such Called Principal is to be redeemed.

Section 5. No sinking fund is to be provided for the bonds of this Supplemental Indenture.

ARTICLE II

MISCELLANEOUS PROVISIONS

Section 1. This Supplemental Indenture is executed by the Company and the Trustee pursuant to provisions of Section 4.02 of the Indenture and the terms and conditions hereof shall be deemed to be a part of the terms and conditions of the Indenture for any and all purposes. The Indenture, as heretofore modified and supplemented and as supplemented by this Supplemental Indenture, is in all respects ratified and confirmed.

Section 2. This Supplemental Indenture shall bind and, subject to the provisions of Article XVI of the Indenture, inure to the benefit of the respective successors and assigns of the parties hereto.

Section 3. Although this Supplemental Indenture is made as of July 27, 2017, effective August 10, 2017, it shall be effective only from and after the actual time of its execution and delivery by the Company and the Trustee on the date indicated by their respective acknowledgements hereto.

Section 4. This Supplemental Indenture may be simultaneously executed in any number of counterparts, and all such counterparts executed and delivered, each as an original, shall constitute but one and the same instrument.

Section 5. The recitals herein are deemed to be those of the Company and not of the Trustee. The Trustee makes no representations as to the validity or sufficiency of this Supplemental Indenture.

IN WITNESS WHEREOF, Northern Illinois Gas Company has caused this Supplemental Indenture to be executed in its name by its Executive Vice President, Chief Financial Officer and Treasurer and its corporate seal to be hereunto affixed and attested by its Corporate Secretary, and The Bank of New York Mellon Trust Company, N.A., as Trustee under the Indenture, has caused this Supplemental Indenture to be executed in its name by one of its Vice Presidents, and its seal to be hereunto affixed and attested by one of its Vice Presidents, all as of the day and year first above written.

NORTHERN ILLINOIS GAS COMPANY

By: /s/Elizabeth W. Reese

Name: Elizabeth W. Reese
Title: Executive Vice President, Chief Financial Officer and Treasurer

ATTEST:

By: /s/Myra C. Bierria

Name: Myra C. Bierria
Title: Corporate Secretary

[Signature Page to 2017 Supplemental Indenture]

THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A.,
*as Trustee*

By: /s/Karen Yu
Name: Karen Yu
Title: Vice President

ATTEST:

By: /sGonzalo Urey
Name: Gonzalo Urey
Title: Vice President

[Signature Page to 2017 Supplemental Indenture]

STATE OF GEORGIA } SS:

COUNTY OF GWINNETT }

I, Ethel Spivey, a Notary Public in the State aforesaid, DO HEREBY CERTIFY that Elizabeth W. Reese, Executive Vice President, Chief Financial Officer and Treasurer of Northern Illinois Gas Company, an Illinois corporation, one of the parties described in and which executed the foregoing instrument, and Myra C. Bierria, Corporate Secretary of said corporation, who are both personally known to me to be the same persons whose names are subscribed to the foregoing instrument as such Executive Vice President, Chief Financial Officer and Treasurer and Corporate Secretary, respectively, and who are both personally known to me to be the Executive Vice President, Chief Financial Officer and Treasurer and Corporate Secretary, respectively, of said corporation, appeared before me this day in person and severally acknowledged that they signed, sealed, executed and delivered said instrument as their free and voluntary act as such Executive Vice President, Chief Financial Officer and Treasurer and Corporate Secretary, respectively, of said corporation, and as the free and voluntary act of said corporation, for the uses and purposes therein set forth.

GIVEN under my hand and notarial seal as of the date listed below.

Dated: July 27, 2017

/s/Ethel Spivey

*Notary Public*

ETHEL SPIVEY

Notary Public, Gwinnett County, Georgia
My Commission Expires August 31, 2018

My Commission expires: August 31, 2018

[Signature Page to 2017 Supplemental Indenture]

**ACKNOWLEDGMENT**

| A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document. |
|---|

State of California
County of Los Angeles )

On 7/25/2017 before me, Alex Dominguez, Notary Public
(insert name and title of the officer)

personally appeared Karen Yu
who proved to me on the basis of satisfactory evidence to be the person ~~(s)~~ whose name ~~(s)~~ is ~~/are~~ subscribed to the within instrument and acknowledged to me that ~~he/~~ she ~~/they~~ executed the same in ~~his/~~ her ~~/their~~ authorized capacity ~~(ies)~~, and that by ~~his/~~ her ~~/their~~ signature ~~(s)~~ on the instrument the person ~~(s)~~, or the entity upon behalf of which the person ~~(s)~~ acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

ALEX DOMINGUEZ
COMM. #2145379
Notary Public - California
Los Angeles County
My Comm. Expires Mar. 6, 2020

Signature /s/Alex Dominguez (Seal)

RECORDING DATA [1]

This Supplemental Indenture was recorded on the following dates in the office of the Recorder of Deeds in certain counties in the State of Illinois, as follows:

| County | Document No. | Date Recorded |
|---|---|---|
| Cook | 1721445049 | 08/02/2017 |
| Adams | 2017R06212 | 07/31/2017 |
| Boone | 2017R03947 | 07/31/2017 |
| Bureau | 2017R03078 | 07/31/2017 |
| Carroll | 2017R1636 | 07/31/2017 |
| Champaign | 2017R14273 | 08/01/2017 |
| DeKalb | 2017007378 | 07/31/2017 |
| DeWitt | 249978 | 07/31/2017 |
| DuPage | R2017-077219 | 07/31/2017 |
| Ford | 267007 | 07/31/2017 |
| Grundy | 571492 | 07/31/2017 |
| Hancock | 2017-1615 | 07/31/2017 |
| Henderson | 178824 | 08/01/2017 |
| Henry | 201704404 | 07/31/2017 |
| Iroquois | 17R2323 | 07/31/2017 |
| Jo Daviess | 395283 | 07/31/2017 |
| Kane | 2017K039441 | 07/31/2017 |
| Kankakee | 201708389 | 07/31/2017 |
| Kendall | 201700011875 | 07/31/2017 |
| Lake | 7416016 | 08/01/2017 |
| LaSalle | 201711285 | 07/31/2017 |
| Lee | 2017003116 | 07/31/2017 |
| Livingston | 2017R-02919 | 07/31/2017 |
| McHenry | 2017R0028003 | 07/31/2017 |
| McLean | 2017-00013855 | 08/02/2017 |
| Mercer | 391400 | 07/31/2017 |
| Ogle | 201704382 | 07/31/2017 |
| Piatt | 362799 | 07/31/2017 |
| Pike | 2017-1717 | 07/31/2017 |
| Rock Island | 2017-13016 | 07/31/2017 |
| Stephenson | 201700158918 | 07/31/2017 |
| Tazewell | 201700011245 | 07/31/2017 |
| Vermilion | 17-05379 | 07/31/2017 |
| Whiteside | 2017-04373 | 07/31/2017 |
| Will | R2017060288 | 08/02/2017 |
| Winnebago | 20171023246 | 08/01/2017 |
| Woodford | 1703250 | 08/08/2017 |

[1] This page to be intentionally omitted from versions submitted for recording.

**Exhibit 10(a)4**

# SOUTHERN COMPANY
# DEFERRED COMPENSATION PLAN

Amended and Restated as of January 1, 2018

**SOUTHERN COMPANY**
**DEFERRED COMPENSATION PLAN**

**TABLE OF CONTENTS**

**SOUTHERN COMPANY**
**DEFERRED COMPENSATION PLAN**

ARTICLE I

Purpose and Adoption of Plan

1.1 Adoption : Southern Company Services, Inc. and the other Employing Companies established the Deferred Compensation Plan for The Southern Electric System effective October 1, 1988. The Plan has been amended from time to time including the good faith amendment and restatement effective January 1, 2005 and then again effective January 1, 2009, both of which were adopted to comply with Code Section 409A, including the proposed, temporary, or final regulations, or other guidance issued by the Secretary of Treasury and the Internal Revenue Service with respect thereto (collectively “409A Guidance”). This amendment and restatement effective January 1, 2018 was adopted to add Deemed Investment Options which align with the investment options offered under the Company’s qualified defined contribution plan, to provide that an employee of a Southern Company Gas affiliated company who had an account under the AGL Resources Inc. Nonqualified Savings Plan on December 31, 2017 is eligible to participate in the Plan effective January 1, 2018, and to make other design changes, as authorized by the Company. Except as otherwise provided herein and consistent with Section 1.3, the terms of the Plan as in effect prior to January 1, 2005 shall continue to be applicable to deferrals made pursuant to the Plan prior to such January 1, 2005.

1.2 Purpose : This Southern Company Deferred Compensation Plan is designed to permit a select group of management or highly compensated employees (“Top-Hat Employees”) within the meaning of Title I of the Employee Retirement Income Security Act of 1974, as amended (“ERISA”) to elect to defer a portion of their regular compensation during each payroll period and to defer all or a portion of certain short-term incentive payments until a specified date or until their death, retirement, or other Separation from Service with an Employing Company. Effective January 1, 2010, the Plan was also designed to accept matching contributions made by employing companies based on a set percentage multiplied by the Compensation deferred by a Participant into the Plan. The Plan is intended to constitute a non-qualified deferred compensation plan that complies with the provisions of Code Section 409A and an unfunded deferred compensation arrangement for Top-Hat Employees governed by ERISA whose benefits shall be paid solely from the general assets of the Employing Companies.

1.3 Schedule of Provisions for Pre-2005 Deferrals : The attached Schedule sets forth the operative provisions of the Plan applicable to “grandfathered” deferrals of Compensation and Incentive Pay made by Participants which are treated by the Employing Companies as not subject to Section 409A of the Code. The Account balance (plus earnings thereon) of the grandfathered deferrals shall only be subject to the provisions set forth in the Schedule. In accordance with transition rules under the 409A Guidance, these provisions are only intended to preserve the rights and features of the “grandfathered” deferrals and are, therefore, not intended to “materially modify” any aspect of such rights and features. Provisions of the Schedule should be so construed whenever necessary or appropriate. Provisions in the Schedule shall only be amended in accordance with the Schedule’s terms.

1.4 409A Transition Elections : At a time and in a manner determined by the Committee, Participants shall make timely elections to conform to the Plan’s terms effective on and after January 1, 2005. Where a Participant fails to make such elections required by the Committee, with regard to the form of distribution ( *i.e.* , lump sum or installment), the Committee shall establish a default distribution form based on the following hierarchy: first, the most current distribution form in effect applicable to the Account balance governed by the Schedule of

Provisions for Pre-2005 Deferrals; if none, lump sum. Such elections are intended to meet the transition requirements of Section 409A of the Code and Internal Revenue Service Notice 2005-1.

ARTICLE II

Definitions

For purposes of the Plan, the following terms shall have the following meanings unless a different meaning is plainly required by the context:

2.1 "Account" shall mean the account or accounts established and maintained by an Employing Company to reflect the interest of a Participant in the Plan resulting from a Participant's deferral of Compensation (plus Employer Matching Contributions made thereon, if any) and/or Incentive Pay each year and adjustments thereto to reflect income, gains, losses, and other credits or charges. Charges to a Participant's Account for distributions shall be posted as of the date the Account is valued in accordance with Section 7.1(a).

2.2 "Board of Directors" shall mean the Board of Directors of the Company.

2.3 "Change in Control Benefits Protection Plan" shall mean the Change in Control Benefits Protection Plan, as approved by the Southern Board, as it may be amended from time to time in accordance with the provisions therein.

2.4 "Closing Price" shall mean the closing price on any trading day of a share of Common Stock based on consolidated trading as defined by the Consolidated Tape Association and reported as part of the consolidated trading prices of New York Stock Exchange listed securities.

2.5 "Code" shall mean the Internal Revenue Code of 1986, as amended from time to time.

2.6 “Committee” shall mean the committee referred to in Section 3.1 hereof.

2.7 “Common Stock” shall mean the common stock of Southern.

2.8 “Company” shall mean Southern Company Services, Inc.

2.9 “Compensation” shall mean, for any year, an Employee’s base wages or salary paid by any Employing Company to an Employee, including amounts contributed by an Employing Company to the Employee Savings Plan as Elective Employer Contributions, as said term is defined in the Employee Savings Plan, pursuant to the Employee’s exercise of his or her deferral option made in accordance with Section 401(k) of the Code, amounts contributed by an Employing Company to the Employee Savings Plan as catch-up contributions pursuant to the Employee’s exercise of his deferral option made thereunder in accordance with the requirements of Section 414(v) of the Code, and amounts contributed by an Employing Company to The Southern Company Flexible Benefits Plan on behalf of the Employee pursuant to his or her salary reduction election under such plan; but disregarding overtime and any reimbursements to an Employee paid by any Employing Company including, but not limited to, reimbursements for such items as moving expenses, automobile expenses, tax preparation expenses, travel and entertainment expenses, and health and life insurance premiums.

2.10 “Deemed Investment Option” shall mean a notional investment option, rather than an actual investment option. A Participant’s account will be hypothetically invested for purposes of determining the earnings or losses to be credited. Deemed Investment Options will be determined by the Committee, and may change from time to time. Any changes to the Deemed Investment Options will be communicated to Participants in a timely manner.

2.11 “Deferral Election” shall mean the Participant’s election to defer a portion of his or her Compensation and/or Incentive Pay pursuant to Article V hereof.

2.12 “Distribution Election” shall mean the election under Article VII hereof, pursuant to which a Participant elects the distribution of his or her Account.

2.13 “Effective Date” of this amendment and restatement shall mean January 1, 2018.

2.14 “Employee” shall mean any person who is currently employed by an Employing Company.

2.15 “Employee Savings Plan” shall mean The Southern Company Employee Savings Plan, as amended from time to time.

2.16 “Employee Stock Ownership Plan” shall mean The Southern Company Employee Stock Ownership Plan, as amended from time to time until merged into the Employee Savings Plan effective December 20, 2006.

2.17 “Employer Matching Contribution” shall mean the matching contribution described in Section 5.1(b).

2.18 “Employing Company” shall mean the Company, or any affiliate or subsidiary (direct or indirect) of The Southern Company, which the Board of Directors may from time to time determine to bring under the Plan and which shall adopt the Plan, and any successor of any of them. The Employing Companies are set forth in Appendix A of the Plan, as may be amended from time to time.

2.19 “Enrollment Date” shall mean January 1 of each Plan Year, and such other dates permitted by the terms of the Plan or as may be determined from time to time by the Committee. No enrollment date shall violate Code Section 409A.

2.20 “ERISA” shall mean the Employee Retirement Income Security Act of 1974, as amended.

2.21 “Exchange Act” shall mean the Securities Exchange Act of 1934, as amended.

2.22 "Incentive Pay" shall mean such short-term incentive pay as the Committee shall permit to be deferred under this Plan for any Plan Year and in all events includes retention compensation where the written retention agreement expressly provides that the retention compensation is to be treated as "incentive pay" which is deferrable under this Plan.

2.23 "Investment Election" shall mean the Participant's election to have his or her deferred Compensation (plus Employer Matching Contributions made thereon, if any) or Incentive Pay notionally invested pursuant to Section 6.2 or Section 6.3 hereof.

2.24 "Key Employee" shall have the meaning ascribed to the term "specified employee" under Code Section 409A(a)(2)(B)(i) and the regulations promulgated thereunder as it applies to a Participant. The Committee shall establish the time period required to determine key employee status.

2.25 "Key-Employee Delay" shall mean the six (6) month delay in the commencement of benefits applicable to Key Employees pursuant to the requirements of Code Section 409A(a)(2)(B)(i) and the regulations promulgated thereunder.

2.26 "Modification Delay" shall mean the requirements permitting a change in time or form of payment as allowed under Code Section 409A(a)(4)(C) and the regulations promulgated thereunder.

2.27 "Non-adopting Company" shall mean any subsidiary or affiliate of Southern which is not an Employing Company.

2.28 "Participant" shall mean an Employee or former employee of an Employing Company who is eligible to and defers Compensation and/or Incentive Pay under the Plan or who was so eligible and had an unpaid Account balance upon his or her death, retirement, or other Separation from Service with an Employing Company. An Employee who had an account under the AGL Resources Inc. Nonqualified Savings Plan as of December 31, 2017 and who is an Employee on January 1, 2018 shall be eligible to participate in this Plan on that date.

2.29 "Pension Plan" shall mean The Southern Company Pension Plan, as amended from time to time.

2.30 "Plan" shall mean the Southern Company Deferred Compensation Plan, amended and restated as of January 1, 2018, as further amended from time to time.

2.31 "Plan Year" shall mean the calendar year.

2.32 "Retirement Income" shall have the same meaning as set forth in the Pension Plan.

2.33 "Separation from Service" shall have the meaning ascribed to this term under Code Section 409A(a)(2)(A)(i) and the regulations promulgated thereunder. For this purpose, Separation from Service shall include a permanent decrease in the level of bona fide services performed by the Participant after a certain date to a level that is twenty percent (20%) or less of the average level of bona fide services performed by the Participant over the immediately preceding thirty-six (36) month period.

2.34 "Southern" shall mean Southern Company, its successors and assigns.

2.35 "Southern Board" shall mean the board of directors of Southern.

2.36 "Total Disability" shall mean a total disability as determined by the Social Security Administration and meeting the requirements of Code Section 409A(a)(2).

2.37 " Trust" shall mean the Southern Company Deferred Compensation Trust.

2.38 "Trustee" shall mean the entity designated as such in the Trust.

2.39 "Unforeseeable Emergency" shall mean a severe financial hardship meeting the requirements of Code Section 409A(a)(2)(B)(ii).

2.40 “Valuation Date” shall mean each trading day of the New York Stock Exchange, or any successor national exchange on which the Common Stock is traded and with respect to which a Closing Price may be determined.

Where the context requires, the definitions of all terms set forth in the Pension Plan, the Employee Savings Plan, and the Employee Stock Ownership Plan shall apply with equal force and effect for purposes of interpretation and administration of the Plan, unless said terms are otherwise specifically defined in the Plan. Words in the masculine gender shall include the feminine and neuter genders, words in the singular shall include the plural, and words in the plural shall include the singular.

## ARTICLE III

## Administration of Plan

3.1 Effective May 31, 2007, the general administration of the Plan shall be placed in the “Committee” which shall consist of the Benefits Administration Committee, the members of which shall be appointed from time to time by the Fiduciary Oversight Committee of the Board of Directors. The Committee shall govern itself in accordance with the terms of the Charter for the Benefits Administration Committee approved by the Fiduciary Oversight Committee of the Board of Directors.

3.2 No member of the Committee shall receive any compensation from the Plan for his or her service.

3.3 (a) The Committee shall administer the Plan in accordance with its terms and shall have all powers necessary to carry out the provisions of the Plan as may be more particularly set forth herein. The Committee shall interpret the Plan and shall determine all questions arising in the administration, interpretation, and application of the Plan. Any such determination by the Committee shall be conclusive and binding on all persons. The Committee shall be the Plan's agent for service of process.

(b) If a claim for benefits under the Plan is denied, in whole or in part, the Committee will provide a written notice of the denial within a reasonable period of time, but not later than 90 days after the claim is received. If special circumstances require more time to process the claim, the Committee will issue a written explanation of the special circumstances prior to the end of the 90 day period and a decision will be made as soon as possible, but not later than 180 days after the claim is received.

The written notice of claim denial will include:

- Specific reasons why the claim was denied;
- Specific references to applicable provisions of the Plan document or other relevant records or papers on which the denial is based, and information about where a Participant or his or her beneficiary may see them;
- A description of any additional material or information needed to process the claim, and an explanation of why such material or information is necessary;
- An explanation of the claims review procedure, including the time limits applicable to such procedure, as well as a statement notifying the Participant or his or her beneficiary of their right to file suit if the claim for benefits is denied, in whole or in part, on review.

Upon request, a Participant or his or her beneficiary will be provided without charge, reasonable access to, and copies of, all non-confidential documents that are relevant to any denial of benefits. A claimant has 60 days from the day he or she receives the original denial to request a review. Such request must be made in writing and sent to the Committee. The request should state the reasons why the claim should be reviewed and may also include evidence or documentation to support the claimant's position.

The Committee will reconsider the claimant's claim, taking into account all evidence, documentation, and other information related to the claim and submitted on the claimant's behalf, regardless of whether such information was submitted or considered in the initial denial of the claim. The Committee will make a decision within 60 days. If special circumstances require more time for this process, the claimant will receive written explanation of the special circumstances prior to the end of the initial 60 day period and a decision will be sent as soon as possible, but not later than 120 days after the Committee receives the request.

No legal action to recover benefits or enforce or clarify rights under a Plan can be commenced until the Participant or his or her beneficiary has first exhausted the claims and review procedures provided under the Plan.

3.4 The Committee may adopt such regulations as it deems desirable for the conduct of its affairs and may appoint such accountants, counsel, actuaries, specialists, and other persons as it deems necessary or desirable in connection with the administration of this Plan.

3.5 The Committee shall be reimbursed by the Employing Companies for all reasonable expenses incurred by it in the fulfillment of its duties, including, but not limited to, fees of accountants, counsel, actuaries, and other specialists, and other costs of administering the Plan.

3.6 (a) The Committee is responsible for the daily administration of the Plan and may appoint other persons or entities to perform any of its fiduciary functions. The Committee and any such appointee may employ advisors and other persons necessary or convenient to help the Committee carry out its duties, including its fiduciary duties. The Committee shall review the work and performance of each such appointee, and shall have the right to remove any such appointee from his or her position. Any person, group of persons, or entity may serve in more than one fiduciary capacity.

(b) The Committee shall maintain accurate and detailed records and accounts of Participants and of their rights under the Plan and of all receipts, disbursements, transfers, and other transactions concerning the Plan. Such accounts, books, and records relating thereto shall be open at all reasonable times to inspection and audit by the Board of Directors and by any persons designated thereby.

(c) The Committee shall take all steps necessary to ensure that the Plan complies with the law at all times. These steps shall include such items as the preparation and filing of all documents and forms required by any governmental agency; maintaining of adequate Participants' records; recording and transmission of all notices required to be given to Participants and their beneficiaries; the receipt and dissemination, if required, of all reports and information received from an Employing Company; securing of such fidelity bonds as may be required by law; and doing such other acts necessary for the proper administration of the Plan. The Committee shall keep a record of all of its proceedings and acts, and shall keep all such books of account, records, and other data as may be necessary for proper administration of the Plan. The Committee shall notify the Employing Companies upon their request of any action taken by the Committee, and when required, shall notify any other interested person or persons.

# ARTICLE IV

## Eligibility

4.1 Any Employee who is determined eligible to participate in accordance with Section 2.28 or 4.2 of the Plan and whose base compensation and salary grade level equals or exceeds such minimum threshold as may be established by the Committee from time to time may elect to participate in the Plan beginning on any Enrollment Date by electing to have his or her Compensation and/or Incentive Pay reduced and such amounts contributed to the Plan in accordance with Article V hereof, and directing the investment of such contributions in accordance with Article VI hereof. An Employee who is eligible to participate and elects to defer Compensation and/or Incentive Pay shall be a Participant in the Plan. The Committee shall be authorized to establish the minimum base compensation and the salary grade level required for eligibility to participate in the Plan, to be effective as of the first day of the next succeeding Plan Year. Notwithstanding the foregoing, any Employee eligible to participate in any similar group employee deferred compensation plan maintained by an Employing Company or maintained by a Non-adopting Company shall be ineligible to defer Compensation or Incentive Pay under this Plan, unless the Committee in its sole discretion shall determine otherwise.

4.2 The Committee shall determine which Employees are eligible to participate in the Plan. Additionally, the Committee shall be authorized to modify the minimum base compensation and the salary grade threshold described in Section 4.1 of the Plan and to rescind the eligibility of any Participant to continue deferrals if this is necessary or advisable to ensure that the Plan is maintained primarily for the purpose of providing deferred compensation to a select group of management or highly compensated employees, as such terms are defined by the ERISA. A Participant whose eligibility is rescinded or who loses eligibility for any reason shall not be eligible to defer Compensation or Incentive Pay until eligibility is restored in accordance with the guidelines established by the Committee.

4.3 The Committee shall have the authority to permit, if it deems appropriate, separate Deferral Elections under Article V hereof, Investment Elections under Article VI hereof, and Distribution Elections under Article VII hereof for Compensation and/or Incentive Pay, respectively. Employer Matching Contributions will be governed by Deferral Elections, Investment Elections, and Distribution Elections as contemplated in the preceding sentence in the same manner as Compensation.

ARTICLE V

Deferral Election

5.1 (a) A Participant may elect to defer payment of a portion of his or her Compensation otherwise payable to him by his or her Employing Company during each payroll period of the next succeeding Plan Year by any whole percentage not to exceed fifty percent (50%) of his or her Compensation, or such greater or lesser amount as shall be determined by the Committee from time to time. A Participant may also elect to defer payment of up to one hundred percent (100%), by whole percentages, of any Incentive Pay otherwise payable to him or her by his or her Employing Company.

(b) With respect to a Participant who elects to defer payment of a portion of his or her Compensation in accordance with (a) above, an Employing Company shall match any such deferred amount at five and one-tenths percent (5.1%) at the time such Compensation is deferred in accordance with Article V.

5.2 The Deferral Election shall be made in a manner prescribed by the Committee and shall state as follows:

(a) That the Participant wishes to make an election to defer the receipt of a portion of his or her Compensation and/or all or a portion of his or her Incentive Pay;

(b) The whole percentage of his or her Compensation and/or Incentive Pay which the Participant elects to defer; and

(c) The Distribution Election under Article VII hereof.

5.3 The Deferral Election of a Participant shall be made by the Participant in a manner prescribed by the Committee and delivered by the date established by the Committee and shall be effective on the first day of the Plan Year immediately following the date of the Deferral Election. A Deferral Election with respect to the deferral of future Compensation and/or Incentive Pay shall be an annual election for each Plan Year; except that, with respect to certain Incentive Pay that is retention compensation, the deferral of such compensation may be set forth in writing in the retention arrangement at the time such arrangement is established. The termination of a Participant's participation in the Plan shall not affect the Participant's Compensation (plus Employer Matching Contributions made thereon, if any) or Incentive Pay previously deferred under the Plan, which shall be invested and distributed in accordance with the Participant's elections and the terms and conditions of the Plan. Such terminated Participant shall become an inactive Participant with respect to eligibility to make future deferrals under this Plan.

5.4 The Committee may cancel the Deferral Election of a Participant who incurs a disability. Any cancellation under this section must occur by the later of the end of the calendar year in which the Participant incurs the disability or the 15$^{th}$ day of the third month after the date the Participant incurs the disability. For purposes of this section, "disability" shall have the meaning set forth in Treasury Regulation Section 1.409A-3(j)(4)(xii).

ARTICLE VI

Participants' Accounts

6.1 Upon the Committee's receipt of a Participant's valid Deferral Election under Article V hereof, beginning as of the Enrollment Date, the designated portion of Compensation (plus Employer Matching Contributions made thereon, if any) and/or Incentive Pay shall be credited to the Participant's Account in accordance with the provisions of this Article VI.

6.2 On the last business day of each month, the Account of each Participant electing in a manner prescribed by the Committee to invest his or her deferred Compensation (plus Employer Matching Contributions made thereon, if any) and/or Incentive Pay for a Plan Year in accordance with this Section 6.2 shall be credited by the Employing Company with a deemed amount equal to the monthly equivalent of the per annum prime rate of interest as published by the Wall Street Journal as the base rate on corporate loans posted as of the last business day of each month by at least seventy five (75%) percent of the United States' largest banks, compounded monthly on any Account balance so invested until such balance is fully distributed.

6.3 The designated portion of the Account of each Participant electing in a manner prescribed by the Committee to invest his or her deferred Compensation (plus Employer Matching Contributions made thereon, if any) and/or Incentive Pay for a Plan Year in accordance with this Section 6.3 shall be credited on the effective date of investment with the deemed number of shares (including fractional shares) of Common Stock which could have been purchased on such date with the dollar amount of such deferral, based upon the Common Stock's Closing Price on the Valuation Date coincident with the date of investment. As of the date on which occurs the payment of dividends on the Common Stock, if any, there shall be credited with respect to the deemed number of shares of Common Stock in the Participant's Account on the applicable dividend record date such additional deemed shares (including fractional shares) of Common Stock as follows:

(a) In the case of cash dividends, such additional deemed shares as could be purchased at the Closing Price on the Valuation Date coincident with the dividend payment date with the dividends which would have been payable on the deemed number of shares previously credited to the Participant's Account as of the dividend record date;

(b) In the case of dividends payable in property other than cash or Common Stock, such additional deemed shares as could be purchased at the Closing Price on the Valuation Date coincident with the dividend payment date with the fair market value of the property which would have been payable on the deemed number of shares previously credited to the Participant's Account as of the dividend record date; or

(c) In the case of dividends payable in Common Stock, such additional deemed shares as would have been payable on the deemed number of shares previously credited to the Participant's Account as of the dividend record date.

6.4 The designated portion of the Account of each Participant electing in a manner prescribed by the Committee to invest his or her deferred Compensation (plus Employer Matching Contributions made thereon, if any) and/or Incentive Pay for a Plan Year in accordance with this Section 6.4 shall be credited on the effective date of investment with the Deemed Investment Option for purposes of determine the earnings or losses to be credited.

6.5 (a) The initial Investment Election by a Participant with respect to deferrals into, Employer Matching Contributions (if any) and earnings on his or her Account shall be made in a manner prescribed by the Committee. Such Investment Elections shall be delivered in accordance with such instructions and shall be effective on the first day of such succeeding Plan Year.

(b) The Participant may transfer in accordance with procedures prescribed by the Committee all or a portion of his Account between investment options. Any such transfer shall constitute an Investment Election as to the amount transferred and shall be effective immediately upon transfer. The timing of transfers between investment options, the procedures for transfer and the valuation of transferred Accounts or portions of Accounts shall be determined by the Committee. In any event, any Participant who is required to file reports pursuant to Section 16(a) of the Exchange Act with respect to equity securities of Southern shall not be permitted to transfer between investment options during any restricted period as determined by the Committee in its sole discretion.

6.6 The Committee shall issue a report at least annually to each Participant holding an Account, setting forth at least the following:

(a) with respect to amounts invested under Section 6.2 and 6.4 hereof, as of the last day of the Plan Year, the Account Balance, the dollar amount of deferrals, Employer Matching Contributions (if any), and earnings thereon, and

(b) with respect to amounts invested under Section 6.3 hereof, the Closing Price of shares of Common Stock credited to each Participant's Account as of the Valuation Date coincident with the last business day of the Plan Year, the total number of deemed shares of Common Stock (and fractions thereof), and the total value of the Participant's deemed investment in Common Stock as of such Valuation Date.

ARTICLE VII

Account Distribution

7.1 (a) When a Participant Separates from Service with an Employing Company or otherwise becomes entitled to commence the distribution of all or a portion of his or her Account, he or she shall be entitled to receive in cash an amount equal to the dollar amount of any deferrals, any Employer Matching Contributions, and any amounts in lieu of interest thereon credited to his or her Account under Section 6.2 hereof, and the dollar value of the product of the Closing Price multiplied by the number of deemed shares of Common Stock (and fractions thereof) credited to his or her Account in accordance Section 6.3 hereof, determined as of the date the Account is valued for distribution. If such date is a non-business day, the Account shall be valued as of the next business day. Such amounts shall be paid in accordance with the Participant's Distribution Elections made in accordance with Section 7.4. No portion of a Participant's Account shall be distributed in Common Stock.

(b) The transfer by a Participant between subsidiaries or affiliates of Southern shall not be deemed to be a termination of employment with an Employing Company for purposes of the Plan.

7.2 In the event that a Participant has made or is deemed to have made a Distribution Election to receive a lump sum distribution of his or her Account, the dollar amount determined under Section 7.1 hereof shall be paid to the Participant as soon as practicable but not later than seventy-five (75) days following the date on which the Participant's Separation from Service occurs or such specified date, if any, elected by the Participant in accordance with Section 7.6. Notwithstanding the foregoing, if a Participant is a Key Employee, such Participant shall be subject to the Key-Employee Delay and the payment of the lump sum following Separation from Service shall be as of the beginning of the seventh full calendar month. Such delay shall not apply to a Participant's election under Section 7.6.

7.3 In the event that a Participant has made a Distribution Election to receive the distribution of his or her Account in annual installments, the first payment shall be made as soon as practicable but not later than seventy-five (75) days following the date on which the Participant's Separation from Service occurs and shall be in an amount equal to the dollar balance in the Participant's Account determined under Section 7.1 hereof, divided by the number of annual installments elected. Subsequent annual installments shall be in an amount equal to the dollar value of the Participant's Account determined under Section 7.1 hereof divided by the number of the remaining annual payments, and shall be paid as of each anniversary of the initial payment date (or what would have been the initial payment date but for the Key-Employee Delay) until the balance of the Participant's Account is paid in full. For purposes of Section 409A of the Code, installments shall be treated as a single payment. Notwithstanding the foregoing, if a Participant is a Key Employee, such Participant shall be subject to the Key-Employee Delay and the first installment payment following Separation from Service shall be as of the beginning of the seventh full calendar month. Upon the death of a Participant prior to the complete distribution of his or her Account in annual installments, the unpaid Account balance shall be paid in accordance with the Distribution Election made by such Participant to the Participant's designated beneficiary. In the event a beneficiary designation is not on file or the designated beneficiary is deceased or cannot be located, payment will be made to the Participant's estate.

7.4 When a Participant makes a Deferral Election, he or she shall make a Distribution Election in a manner prescribed by the Committee. Such Distribution Election shall apply only to the amounts attributable to that specified Deferral Election (including any Employer Matching Contribution made on a deferral of Compensation) and may not be subsequently revoked, except that one or more Distribution Elections may be modified by a Participant but only if such modification meets the requirements of a Modification Delay. Each year's Deferral Election is allowed a one-time re-deferral in which the time and/or form of payment can be modified. In accordance with Section 409A of the Code, any changes to time and/or form of payment, must be made at least 12 months before the originally scheduled commencement date, and result in a delay of at least five years from the originally scheduled commencement date. If disability, death, or a Separation of Service occur within 12 months after the re-deferral election and cause the distribution to be made less than 12 months before the originally scheduled commencement date, the original Deferral Election shall apply and the re-deferral election shall be revoked.

7.5 Upon the death of a Participant prior to Separation from Service, the Account balance shall be paid to the Participant's designated beneficiary determined pursuant to Section 7.9 in the form of a lump sum as soon as practicable but not more than seventy-five (75) days following the date of the Participant's death.

7.6 In addition to distributions commencing upon a Separation from Service, Participants may elect in a manner prescribed by the Committee to commence payment of all or a portion of his or her Deferral Election as of a specified date. Distributions that commence prior to Separation from Service must be paid in a lump sum.

7.7 Upon the Total Disability of a Participant, the balance of his or her Account shall be paid in accordance with Participant's Deferral Election commencing as of such Participant's Separation from Service and, if applicable, as of any date specified by the Participant pursuant to an election under Section 7.6.

7.8 Upon the occurrence of an Unforeseeable Emergency and an application made by a Participant or his or her beneficiary, the Committee may in its sole discretion determine to make a lump-sum payment up to the amount in the Participant's Account in accordance with the requirements of Code Section 409A to satisfy such Unforeseeable Emergency. Such lump-sum payment shall reduce pro rata the amount attributable to each annual Deferral Election made by the Participant.

7.9 Beneficiary designations may be made or changed by the Participants in a manner prescribed by the Committee at any time without the consent of any prior beneficiary. In the event a beneficiary designation is not on file or the designated beneficiary is deceased or cannot be located following the death of the Participant, payment will be made to the Participant's estate.

7.10 In the event a Participant who is employed on or after January 1, 1999 with an "Employing Company" (as defined in the Change in Control Benefits Protection Plan) disputes the calculation of his Account or payment of amounts due under the terms of the Plan, such Participant has recourse against the Company, the Employing Company by which Participant is employed, if different, the Plan, and the Trust for the payment of benefits to the extent the Trust so provides.

7.11 The provisions of the Change in Control Benefits Protection Plan are incorporated herein by reference to determine the occurrence of a change in control or preliminary change in control of Southern or an Employing Company, the benefits to be provided hereunder, and the funding of the Trust in the event of such a change in control. Any modifications to the Change in Control Benefits Protection Plan are likewise incorporated herein and are otherwise intended to comply with 409A of the Code.

## ARTICLE VIII

### Miscellaneous Provisions

8.1 Neither the Participant, his or her beneficiary, nor his or her legal representative shall have any rights to commute, sell, assign, transfer, or otherwise convey the right to receive any payments hereunder, which payments and the rights thereto are expressly declared to be non-assignable and nontransferable. Any attempt to assign or transfer the right to payments of this Plan shall be void and have no effect.

8.2 Except as expressly limited under the terms of the Trust, an Employing Company maintaining an Account for the benefit of a Participant shall neither reserve nor specifically set aside funds for the payment of its obligations under the Plan. In any event, such obligations shall be paid or deemed to be paid solely from the general assets of the Employing Companies. Participants shall only have the status of a general, unsecured creditor of the Employing Company(ies). Notwithstanding that a Participant shall be entitled to receive the balance of his or her Account under the Plan, the assets from which such amount may be paid shall at all times be subject to the claims of the creditors of the Participants' Employing Companies.

8.3 Except for the provisions of Section 7.10 hereof, which may not be amended following a "Southern Change in Control" or "Subsidiary Change in Control" (as defined in the Change in Control Benefits Protection Plan), the Plan may be amended, modified, or terminated by the Board of Directors in its sole discretion at any time and from time to time; provided, however, that no such amendment, modification, or termination shall impair any rights to any amounts which have been earned or deferred under the Plan prior to such amendment, modification, or termination. Effective March 1, 2006, the Plan may also be amended by the Committee (a) if such amendment does not involve a substantial increase in cost to any

Employing Company, or (b) as may be necessary, proper, or desirable in order to comply with laws or regulations enacted or promulgated by any federal or state governmental authority.

8.4 It is expressly understood and agreed that the payments made in accordance with the Plan are in addition to any other benefits or compensation to which a Participant may be entitled or for which he or she may be eligible, whether funded or unfunded, by reason of his or her employment with any Employing Company.

8.5 There may be deducted from any payment under the Plan in accordance with the requirements of 409A of the Code the amount of any tax owed by the Participant required by any governmental authority to be withheld and paid over by an Employing Company to such governmental authority for the account of the person entitled to such distribution. The Employing Company may also seek payment for tax owed by the Participant directly from such Participant or may withhold such tax from compensation otherwise paid to such Participant.

8.6 Any Compensation or Incentive Pay deferred by a Participant while employed by an Employing Company and any Transferred Amounts shall not be considered “compensation,” as the term is defined in the Employee Savings Plan, the Employee Stock Ownership Plan, or the Pension Plan unless any one or all of those plans expressly provides otherwise. Distributions from a Participant’s Account shall not be considered wages, salaries, or compensation under any other employee benefit plan.

8.7 No provision of this Plan shall be construed to affect in any manner the existing rights of an Employing Company to suspend, terminate, alter, modify, whether or not for cause, the employment relationship of the Participant and his or her Employing Company.

8.8 For the avoidance of doubt, the provisions of the Plan effective in the Plan’s amendment and restatement dated January 1, 2004 (“2004 Plan”) concerning Mirant Shares were applied through the liquidation of Mirant Shares as a form of investment in the Plan as of June 30, 2006. Although these provisions concerning Mirant Shares are not restated in this amendment and restatement, a Participant's rights concerning Mirant Shares are as set forth in such 2004 Plan. To this limited extent, the provisions in the 2004 Plan concerning Mirant Shares are incorporated herein.

8.9 This Plan, and all rights under it, shall be governed by and construed in accordance with the laws of the State of Georgia without regard to conflict of laws principles to the extent not preempted by ERISA.

IN WITNESS WHEREOF, the amended and restated Plan has been executed by duly authorized officers of Southern Company Services, Inc. pursuant to resolutions of the Board of Directors and the Committee, this 12th day of December, 2017.

SOUTHERN COMPANY SERVICES, INC.

By: /s/Nancy E. Sykes

Name: Nancy E. Sykes

Its: EVP & Chief Human Resources Officer

**APPENDIX A**

**THE SOUTHERN COMPANY**
**DEFERRED COMPENSATION PLAN**

**EMPLOYING COMPANIES AS OF JANUARY 1, 2018**

Alabama Power Company
Georgia Power Company
Gulf Power Company
Mississippi Power Company
Southern Communications Services, Inc.
Southern Company Energy Solutions, LLC
Southern Company Gas' affiliated companies
Southern Company Services, Inc.
Southern Nuclear Operating Company, Inc.
Southern Power Company

**SCHEDULE OF PROVISIONS**
**FOR PRE-2005 DEFERRALS**

ARTICLE I

Purpose

1.1 Schedule of Provisions for Pre-2005 Deferrals : This Schedule sets forth the operative provisions of the Plan applicable to “grandfathered” deferrals of Compensation and Incentive Pay made by Participants which are treated by the Employing Companies as not subject to Section 409A of the Code. The Account balance (plus earnings thereon) of the grandfathered deferrals shall only be subject to the provisions set forth in this Schedule. In accordance with the 409A Guidance, these provisions are only intended to preserve the rights and features of the “grandfathered” deferrals and are, therefore, not intended to “materially modify” any aspect of such rights and features. Provisions of this Schedule should be so construed whenever necessary or appropriate. Provisions in this Schedule shall only be amended in accordance with this Schedule’s terms.

ARTICLE II

Definitions

For purposes of this Schedule, the following terms shall have the following meanings unless a different meaning is plainly required by the context:

2.1 “Account” shall mean the account or accounts established and maintained by an Employing Company to reflect the interest of a Participant in the Plan solely pursuant to the terms of this Schedule resulting from a Participant’s deferral of Compensation and/or Incentive Pay and adjustments thereto to reflect income, gains, losses, and other credits or charges. The Account amount is attributable to those deferrals which are not subject to Section 409A of the

Code. Charges to Participant's Accounts for distributions shall be posted as of the date the Account is valued for distribution.

2.2 "Change in Control Benefits Protection Plan" shall mean the Change in Control Benefits Protection Plan, as approved by the board of directors of Southern, as it may be amended from time to time in accordance with the provisions therein.

2.3 "Closing Price" shall mean the closing price on any trading day of a share of the Common Stock based on consolidated trading as defined by the Consolidated Tape Association and reported as part of the consolidated trading prices of New York Stock Exchange listed securities.

2.4 "Committee" shall mean the committee referred to in Section 3.1 of this Schedule.

2.5 "Common Stock" shall mean the common stock of Southern.

2.6 "Company" shall mean Southern Company Services, Inc.

2.7 "Compensation" shall mean the rate of an Employee's base wages or salary paid by any Employing Company to an Employee, including amounts contributed by an Employing Company to the Employee Savings Plan as Elective Employer Contributions, as said term is defined in the Employee Savings Plan, pursuant to the Employee's exercise of his or her deferral option made in accordance with Section 401(k) of the Code, amounts contributed by an Employing Company to the Employee Savings Plan as catch-up contributions pursuant to the Employee's exercise of his deferral option made thereunder in accordance with the requirements of Section 414(v) of the Code, and amounts contributed by an Employing Company to The Southern Company Flexible Benefits Plan on behalf of the Employee pursuant to his or her salary reduction election under such plan; but disregarding overtime and any reimbursements to an Employee paid by any Employing Company including, but not limited to, reimbursements for such items as moving expenses, automobile expenses, tax preparation expenses, travel and entertainment expenses, and health and life insurance premiums.

2.8 “Deferral Election” shall mean the Participant’s election to defer a portion of his or her Compensation and/or Incentive Pay pursuant to Article V of the main body of the Plan.

2.9 “Distribution Election” shall mean the election under Article VII of this Schedule, pursuant to which a Participant elects the distribution of the balance of his or her Account to be made in either a lump sum or in up to ten (10) annual installments following the Participant’s death, disability, retirement, or other termination of Employment with an Employing Company.

2.10 “Employee Savings Plan” shall mean The Southern Company Employee Savings Plan, as amended from time to time.

2.11 “Employee Stock Ownership Plan” shall mean The Southern Company Employee Stock Ownership Plan, as amended from time to time.

2.12 “Employing Company” shall mean the Company, or any affiliate or subsidiary (direct or indirect) of Southern Company, which the board of directors of the Company may from time to time determine to bring under the Plan and which shall adopt the Plan, and any successor of any of them. The Employing Companies are set forth in Appendix A of the Plan, as may be amended from time to time.

2.13 “Exchange Act” shall mean the Securities Exchange Act of 1934, as amended.

2.14 “Incentive Pay” shall mean such short-term incentive pay as the Committee shall permit to be deferred under the Plan for any Plan Year.

2.15 “Investment Election” shall mean the Participant’s election to have his or her deferred Compensation or Incentive Pay invested pursuant to Section 6.1 or Section 6.2 of this Schedule.

2.16 “Participant” shall mean for purposes of this Schedule an Employee or former employee of an Employing Company who has an unpaid Account balance governed by the terms of this Schedule upon his or her death, disability, retirement, or other termination of employment with an Employing Company.

2.17 “Plan” shall mean the Southern Company Deferred Compensation Plan, amended and restated as of January 1, 2018 which includes this Schedule, as may be further amended from time to time.

2.18 “Plan Year” shall mean the calendar year.

2.19 “Southern” shall mean Southern Company, its successors and assigns.

2.20 “Trust” shall mean the Southern Company Deferred Compensation Trust.

2.21 “Valuation Date” shall mean each trading day of the New York Stock Exchange, or any successor national exchange on which the Common Stock is traded and with respect to which a Closing Price may be determined.

Where the context requires, the definitions of all terms set forth in the Pension Plan, the Employee Savings Plan, and the Employee Stock Ownership Plan shall apply with equal force and effect for purposes of interpretation and administration of the Plan, unless said terms are otherwise specifically defined in the Plan. Words in the masculine gender shall include the feminine and neuter genders, words in the singular shall include the plural, and words in the plural shall include the singular.

ARTICLE III

Administration of Schedule

3.1 Article III of the main body of the Plan is herein incorporated into this Schedule by reference. Any amendment to Article III of the main body of the Plan shall operate as amendment to this Article III of the Schedule.

ARTICLE IV

Eligibility

4.1 For so long as an Employee has an Account balance governed by this Schedule, he or she shall be a Participant in the Plan for purposes of this Schedule, and such Account balance shall be maintained and administered solely in accordance with the terms of this Schedule.

ARTICLE V

Deferral Election

5.1 No new deferral elections may be made which are subject to this Schedule.

ARTICLE VI

Participants' Accounts

6.1 On the last business day of each month, the Account of each Participant electing in a manner prescribed by the Committee to invest his or her deferred Compensation and/or Incentive Pay for a Plan Year in accordance with this Section 6.1 shall be credited by the Employing Company with a deemed amount equal to the monthly equivalent of the per annum prime rate of interest as published by the Wall Street Journal as the base rate on corporate loans posted as of the last business day of each month by at least seventy five (75%) percent of the

United States' largest banks, compounded monthly on any Account balance so invested until such balance is fully distributed.

6.2 The designated portion of the Account of each Participant electing in a manner prescribed by the Committee to invest his or her deferred Compensation and/or Incentive Pay for a Plan Year in accordance with this Section 6.2 shall be credited on the effective date of investment with the deemed number of shares (including fractional shares) of Common Stock which could have been purchased on such date with the dollar amount of such deferral, based upon the Common Stock's Closing Price on the Valuation Date coincident with the date of investment. As of the date on which occurs the payment of dividends on the Common Stock, if any, there shall be credited with respect to the deemed number of shares of Common Stock in the Participant's Account on the applicable dividend record date such additional deemed shares (including fractional shares) of Common Stock as follows:

(a) In the case of cash dividends, such additional deemed shares as could be purchased at the Closing Price on the Valuation Date coincident with the dividend payment date with the dividends which would have been payable on the deemed number of shares previously credited to the Participant's Account as of the dividend record date;

(b) In the case of dividends payable in property other than cash or Common Stock, such additional deemed shares as could be purchased at the Closing Price on the Valuation Date coincident with the dividend payment date with the fair market value of the property which would have been payable on the deemed number of shares previously credited to the Participant's Account as of the dividend record date; or

(c) In the case of dividends payable in Common Stock, such additional deemed shares as would have been payable on the deemed number of shares previously credited to the Participant's Account as of the dividend record date.

6.3 The Participant may transfer in accordance with procedures prescribed by the Committee all or a portion of his Account between investment options. Any such transfer shall constitute an Investment Election as to the amount transferred and shall be effective immediately upon transfer. The timing of transfers between investment options, the procedures for transfer, and the valuation of transferred Accounts or portions of Accounts shall be determined by the Committee.

6.4 The Committee shall issue a report at least annually to each Participant holding an Account, setting forth at least the following:

(a) with respect to amounts invested under Section 6.1 hereof, as of the last day of the Plan Year, the Account Balance, the dollar amount of deferrals, and earnings thereon, and

(b) with respect to amounts invested under Section 6.2 hereof, the Closing Price of shares of Common Stock credited to each Participant's Account as of the Valuation Date coincident with the last business day of the Plan Year, the total number of deemed shares of Common Stock (and fractions thereof), and the total value of the Participant's deemed investment in Common Stock as of such Valuation Date.

ARTICLE VII

Account Distribution

7.1 (a) When a Participant retires or terminates his or her employment with an Employing Company, he or she shall be entitled to receive in cash an amount equal to the dollar amount of any deferrals and any amounts in lieu of interest thereon credited to his or her

Account under Section 6.1 hereof, and the dollar value of the product of the Closing Price multiplied by the number of deemed shares of Common Stock (and fractions thereof) credited to his or her Account in accordance Section 6.2 hereof, determined as of the date the Account is valued for distribution. If such date is a non-business day, the Account shall be valued as of the next business day. Such amounts shall be paid in accordance with the Participant's most recent Distribution Election effective in accordance with Section 7.4. No portion of a Participant's Account shall be distributed in Common Stock.

(b) The transfer by a Participant between subsidiaries or affiliates of Southern shall not be deemed to be a termination of employment with an Employing Company for purposes of the Plan.

7.2 In the event that a Participant's most recent Distribution Election effective in accordance with Section 7.4 is to receive a lump-sum distribution of his or her Account, the dollar amount determined under Section 7.1 hereof shall be paid to the Participant not later than sixty (60) days following the date on which the Participant's termination of employment occurs, or as soon as reasonably practicable thereafter.

7.3 In the event that a Participant's most recent Distribution Election effective in accordance with Section 7.4 is to receive the distribution of his or her Account in annual installments, the first payment shall be made not later than sixty (60) days following the date on which the Participant's termination of employment occurs, or as soon as reasonably practicable thereafter, and shall be in an amount equal to the dollar balance in the Participant's Account determined under Section 7.1 hereof, divided by the number of annual installments elected. Subsequent annual installments shall be in an amount equal to the dollar value of the Participant's Account determined under Section 7.1 hereof divided by the number of the remaining annual payments, and shall be paid as soon as practicable following each anniversary of the initial payment date until the balance of the Participant's Account is paid in full.

7.4 The Participants' initial Distribution Elections may not be revoked and shall govern the distribution of the Participants' Accounts. Notwithstanding the foregoing, and except as otherwise provided herein, the Committee may, in its sole discretion, upon application by a Participant, accept an amended Distribution Election from a Participant provided the election is made not later than the 366th day prior to a distribution of such Participant's Account in accordance with the terms of the Plan; provided further, however, that any Participant who is required to file reports pursuant to Section 16(a) of the Securities and Exchange Act of 1934, as amended, with respect to equity securities of Southern shall not be permitted to amend his or her Distribution Election during any time period for which such Participant is required to file any such reports with respect to the portion of his or her Account invested in accordance with the provisions of Section 6.2 of this Schedule, unless the Committee in its sole discretion shall determine otherwise.

7.5 Upon the death of a Participant prior to the complete distribution of his or her Account, the unpaid Account balance shall be paid in the sole discretion of the Committee (a) in a lump sum to the Participant's designated beneficiary within sixty (60) days following the date on which the Committee is provided evidence of the Participant's death (or as soon as reasonably practicable thereafter) or (b) in accordance with the Distribution Election made by such Participant. In the event a beneficiary designation is not on file or the designated beneficiary is deceased or cannot be located, payment will be made to the Participant's estate.

7.6 Beneficiary designations may be changed by the Participants at any time without the consent of any prior beneficiary.

7.7 Upon the total disability of a Participant, as determined by the Social Security Administration, prior to the complete distribution of his or her Account, the unpaid balance of his or her Account shall be paid in the sole discretion of the Committee (a) in a lump sum to the Participant or his or her legal representative within sixty (60) days following the date on which the Committee receives notification of the determination of disability by the Social Security Administration (or as soon as reasonable practicable thereafter) or (b) in accordance with the Participant's Deferral Election.

7.8 Upon application made by a Participant, his or her designated beneficiary, or an authorized legal representative, the Committee may in its sole discretion determine to accelerate payments or, in the event of death or total disability (as determined by Social Security Administration), may extend or otherwise make payments in a manner different from the manner in which such payment would otherwise be made under the Participant's Deferral Election in the absence of such determination.

7.9 In the event a Participant who is employed on or after January 1, 1999 with an "Employing Company" (as defined in the Change in Control Benefits Protection Plan) disputes the calculation of his Account or payment of amounts due under the terms of this Plan, such Participant has recourse against the Company, the Employing Company by which Participant is employed, if different, the Plan, and the Trust for the payment of benefits to the extent the Trust so provides.

7.10 The provisions of the Change in Control Benefit Benefits Protection Plan are incorporated herein by reference to determine the occurrence of a change in control or preliminary change in control of Southern or an Employing Company, the benefits to be provided hereunder, and the funding of the Trust in the event of such a change in control. Any modifications to the Change in Control Benefits Protection Plan are likewise incorporated herein.

ARTICLE VIII

Miscellaneous Provisions

8.1 Except for Section 8.3 of the main body of the Plan, Article VIII is hereby incorporated by reference into this Schedule. Any amendment to Article VIII of the main body of the Plan shall operate as an amendment to this Article VIII of the Schedule except that Section 8.2 below shall set forth the sole method for amending and/or terminating this Schedule.

8.2 This Schedule may be amended, modified, or terminated by the Board of Directors in its sole discretion at any time and from time to time by resolution expressly modifying this Schedule; provided, however, that (a) Section 7.10 of this Schedule may not be amended following a “Southern Change in Control” or “Subsidiary Change in Control” (as defined in the Change in Control Benefits Protection Plan), (b) no such amendment, modification, or termination shall impair any rights to any amounts which have been earned or deferred under the Plan prior to such amendment, modification, or termination and/or (c) Article III and Section 8.1 of this Schedule may be amended in accordance with their terms. Payment in full in cash of the amount credited to a Participant’s Account governed by this Schedule as of the date of any amendment, modification, or termination of the Plan shall not be deemed to be an impairment of the Participant’s rights under the Plan. It is the Company’s intent that any modification to this Schedule shall not constitute nor shall it be interpreted to be a “material modification” of any right or feature of this Schedule as such term is defined under the 409A Guidance.

Exhibit 10(a)16

**SECOND AMENDMENT TO THE SOUTHERN COMPANY**
**SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN**

**WHEREAS,** the Board of Directors of Southern Company Services, Inc. (the "Company") heretofore established and adopted the Southern Company Supplemental Executive Retirement Plan, as amended and restated effective June 30, 2016 (the "Plan"); and

**WHEREAS,** the Company desires to amend the Plan to add "Southern Power Company" as an Affiliated Employer; and

**WHEREAS,** Section 6.2 of the Plan provides in relevant part that the Plan may be amended or modified at any time by the Company.

**NOW, THEREFORE,** effective as the date set forth below, the Company hereby amends the Plan as follows:

**1.**

Effective January 1, 2018, Appendix A of the Plan is hereby amended by deleting it in its entirety and replacing it with the following:

**APPENDIX A**

**THE SOUTHERN COMPANY SUPPLEMENTAL**
**EXECUTIVE RETIREMENT PLAN**

**AFFILIATED EMPLOYERS AS OF JANUARY 1, 2018**

Alabama Power Company
Georgia Power Company
Gulf Power Company
Mississippi Power Company
Southern Communications Services, Inc.
Southern Company Energy Solutions, LLC
Southern Company Services, Inc.
Southern Nuclear Operating Company, Inc.
Southern Power Company

**2.**

Except as amended herein by this Second Amendment, the Plan shall remain in full force and effect.

**[SIGNATURE ON FOLLOWING PAGE]**

IN WITNESS WHEREOF, the Company, through its duly authorized officer, has adopted this Second Amendment to the Southern Company Supplemental Executive Retirement Plan, as amended and restated as of June 30, 2016 this 29th day of November, 2017.

**SOUTHERN COMPANY SERVICES, INC.**

By: /s/Nancy E. Sykes

Name: Nancy E. Sykes

Its: EVP & Chief Human Resources Officer

Exhibit 10(a)17

**SECOND AMENDMENT TO THE SOUTHERN COMPANY SUPPLEMENTAL BENEFIT PLAN**

**WHEREAS,** the Board of Directors of Southern Company Services, Inc. (the "Company") heretofore established and adopted the Southern Company Supplemental Benefit Plan, as amended and restated effective June 30, 2016 (the "Plan"); and

**WHEREAS,** the Company desires to amend the Plan to implement changes to (i) the calculation of the Single-Sum Amount for a Participant who first participates in the Plan on or after January 1, 2018 or who is rehired on or after January 1, 2018, (ii) change the eligibility requirements effective January 1, 2018, (iii) add "Southern Power Company" and "Southern Company Gas' affiliated companies" as Employing Companies, and (iv) provide for the merger of the AGL Resources Inc. Excess Benefit Plan with and into the Plan, and special rules associated with the transferred benefits; and

**WHEREAS,** Section 6.2 of the Plan provides in relevant part that the Plan may be amended or modified at any time by the Company.

**NOW, THEREFORE,** effective as the date set forth below, the Company hereby amends the Plan as follows:

**1.**

Section 2.11 of the Plan is hereby amended by deleting it in its entirety and replacing it with the following:

2.11 "Discount Rate" shall mean:

(a) For a Participant who first participates in the Plan before January 1, 2018 and is not rehired on or after January 1, 2018. The thirty (30) year Treasury yield as published by the Department of Treasury for purposes of compliance with Code Section 417(e) determined for September of the calendar year prior to the calendar year in which a Participant Separates from Service provided that the maximum rate shall not exceed six percent (6%).

(b) For a Participant who first participates in the Plan on or after January 1, 2018 or is rehired on or after January 1, 2018. The "Applicable Interest Rate" defined by Code Section 417(e)(3) and determined for September of the calendar year prior to the calendar year in which a Participant Separates from Service.

**2.**

Section 2.34 of the Plan is hereby amended by deleting it in its entirety and replacing it with the following:

2.34 "Single-Sum Amount" shall mean:

(a) For a Participant who first participates in the Plan before

January 1, 2018 and is not rehired on or after January 1, 2018. The discounted value of the Pension Benefit based on a single life annuity form of benefit payable for an Expected Average Lifetime calculated using the Discount Rate. This Single-Sum Amount calculation shall be determined effective as of the first installment to be made under Section 5.2 (ignoring for this purpose any Key-Employee Delay) taking into account the following: (a) no reductions are applied for the Death Benefit Charge-Basic or the Death Benefit Charge-Enhanced for pre-retirement death benefit coverage under the Pension Plan; and (b) the Pension Benefit and Expected Average Lifetime shall be based on the Participant's age as of such first installment date.

(b) For a Participant who first participates in the Plan on or after January 1, 2018 or is rehired on or after January 1, 2018.

(1) *Participant retires under the terms of the Pension Plan at Separation from Service* . The actuarial present value of the Pension Benefit payable as a single life annuity calculated using the Discount Rate and the "Applicable Mortality Table" within the meaning of Code Section 417(e)(3) described by the Secretary of the Treasury for the calendar year in which the Participant Separates from Service. This Single-Sum Amount calculation shall be determined effective as of the first installment to be made under Section 5.2 (ignoring for this purpose any Key-Employee Delay) taking into account the following: (a) no reductions are applied for the Death Benefit Charge-Basic or the Death Benefit Charge-Enhanced for pre-retirement death benefit coverage under the Pension Plan; and (b) the actuarial present value calculation reflects an immediate factor; and (c) the Pension Benefit is payable as of the first installment to be made under Section 5.2 (ignoring for this purpose any Key-Employee Delay).

(2) *Participant is not eligible to retire under the terms of the Pension Plan at Separation from Service* . The actuarial present value of the Pension Benefit payable as a single life annuity calculated using the Discount Rate and the "Applicable Mortality Table" within the meaning of Code Section 417(e)(3) described by the Secretary of the Treasury for the calendar year in which the Participant Separates from Service. This Single-Sum Amount calculation shall be determined effective as of September 1 of the calendar year following the calendar year of Separation from Service taking into account the following: (a) no reductions are applied for the Death Benefit Charge-Basic or the Death Benefit Charge-Enhanced for pre-retirement death benefit coverage under the Pension Plan; and (b) the actuarial present value calculation reflects a deferred to Normal Retirement Date factor; and (c) the Pension Benefit is payable at the Participant's Normal Retirement Date.

**3.**

Section 4.2 of the Plan is hereby amended by deleting it in its entirety and replacing it with the following:

(b) Determination of Eligibility . Effective beginning January 1, 2018, Employees are determined to be eligible to participate in the Plan if they meet one or more of the criteria outlined under Section 4.1. For the avoidance of doubt, eligibility beginning January 1, 2018, is based on an Employee meeting one or more of the criteria in 2018 and later Plan Years. Prior to January 1, 2018, the Administrative Committee determined which Employees were eligible to participate in the Plan. Employees who were determined to be eligible to participate by the Administrative Committee prior to January 1, 2018, will continue to participate in the Plan on and after January 1, 2018. Upon becoming a Participant, an Employee shall be deemed to have assented to the Plan and to any amendments hereafter adopted. The Administrative Committee shall be authorized to rescind the eligibility of any Participant if necessary to ensure that the Plan is maintained primarily for the purpose of providing deferred compensation to a select group of management or highly compensated employees under the Employee Retirement Income Security Act of 1974, as amended. In addition, a Participant shall not be eligible for a Pension Benefit under the Plan unless such Participant shall be entitled to a vested benefit under the Pension Plan. If an Employee who was employed by Mirant Corporation (f/k/a Southern Energy, Inc.) ("Mirant") or an affiliate thereof on or after April 2, 2001 is thereafter employed by an Employing Company, he shall be treated the same as a new hire and none of his service with Mirant shall be considered as Accredited Service under Section 5.1. Effective beginning January 1, 2018, a Participant's "earnings" that are defined under the Pension Plan shall not include commissions earned by any commissioned Employee for purposes of determining eligibility for the Plan.

**4.**

Section 5.1(b) of the Plan is hereby amended by deleting it in its entirety and replacing it with the following:

(b) For purposes of this Section 5.1, the Pension Benefit of a Participant shall be calculated based on the Participant's "earnings" that are defined under the Pension Plan, as modified below, without regard to the limitations of Section 401(a)(17) of the Code. For purposes of determining such "earnings," all incentive pay earned while he is an Employee under any annual group incentive plans, as defined in Section 4.2 of the Pension Plan, shall be considered, provided such incentive award was earned on or after January 1, 1994. However, incentive pay shall only be included in a Pre-2016 Participant's "earnings" for purposes of calculating such Pre-2016 Participant's Pension Benefit using the 1.25% formula described in Section 4.2 of the Pension Plan. Effective beginning January 1, 2018, a Participant's "earnings" shall not include commissions earned by any commissioned Employee for purposes of determining the Pension Benefit calculated under the Plan.

**5.**

Section 5.2(e) of the Plan is hereby amended by deleting it in its entirety and replacing it with the following:

(e) Participants Who Terminate with Vested Benefits.

(1) *General Rule* . With respect to a Participant who Separates from Service on or after March 1, 2007, who is not eligible to retire under Sections 4.1(a), 4.1(b) or 4.1(c) of the Pension Plan, but who is vested in his Retirement Income under Section 4.1(d) of the Pension Plan, notwithstanding anything to the contrary, such Participant shall receive a Pension Benefit in the form of a single payment made as of September 1 of the calendar year following the calendar year of termination from employment.

(2) *For a Participant who first participates in the Plan before January 1, 2018 and is not rehired on or after January 1, 2018* . The single payment is equal to (A) divided by (B) below:

(A) The Single-Sum Amount determined as if the Participant's first installment date was to be coincident with his Normal Retirement Date.

(B) The sum of one (1) plus the Discount Rate raised to a power equal to the number of years and months between the Participant's Normal Retirement Date and the September 1 of the calendar year following the calendar year of termination from employment.

(3) *For a Participant who first participates in the Plan on or after January 1, 2018 or is rehired on or after January 1, 2018* . The single payment is equal to the Single-Sum Amount described in Section 2.34(b)(2).

For the avoidance of doubt, the Discount Rate used for the calculations in Section 5.2(e)(2) and 5.2(e)(3) above is to be the Discount Rate applicable for the calendar year the Participant Separates from Service.

(4) *Death Benefits* . With respect to a Participant who first participates in the Plan before January 1, 2018 and is not rehired on or after January 1, 2018, to which this Section 5.2(e) applies, if such a Participant dies after Separation from Service but prior to payment in accordance with Section 5.2(e)(1) above and prior to July 1, 2017, the Provisional Payee, if any, shall receive the single payment provided in Section 5.2(e)(2) above at the same time the Participant would have received such payment if he had not died.

If a Participant dies on or after July 1, 2017, refer to Section 5.2(f).

(5) *Total Disability.* The determination of whether of Participant has a Separation from Service by reason of a Total Disability will be made in accordance with Code Section 409A and such Participant shall receive a Pension Benefit in the form of a single payment made as of September 1 of the calendar year following the calendar year in which the Separation from Service occurs.

**6.**

Section 5.2(f) of the Plan is hereby amended by deleting it in its entirety and replacing it with the following:

(f) Designated Beneficiary Death Benefit on and after July 1, 2017.

(1) If a Participant dies on or after July 1, 2017, while in active service or after Separation from Service with a vested Pension Benefit in this Plan, and

(A) If such Participant is a Pre-2016 Participant, and (i) he has elected his Spouse as his sole Designated Beneficiary, such Spouse shall receive 100% of the Single-Sum Amount, or (ii) he has elected a Designated Beneficiary(ies) which is not his Spouse, such Designated Beneficiary(ies) shall receive 50% of the Single-Sum Amount with an equal portion of such Single-Sum Amount payable to each such living Designated Beneficiary, or

(B) If such Participant is a 2016 Participant, the Designated Beneficiary(ies) (whether or not the Spouse) shall receive 50% of the Single-Sum Amount with an equal portion of such Single-Sum Amount payable to each such living Designated Beneficiary.

(2) The Single-Sum Amount described in Section 5.2(f)(1) above is payable to the Designated Beneficiary(ies) on the first of the month following the date of the Pre-2016 Participant's or the 2016 Participant's death. The benefit will be payable as soon as administratively feasible after the Designated Beneficiary(ies) have been confirmed and located.

(3) If a Pre-2016 Participant or a 2016 Participant who first participates in the Plan before January 1, 2018 and is not rehired on or after January 1, 2018, dies while in active service and prior to age 50, the Single-Sum Amount described in Section 5.2(f)(1) above is calculated as (A) divided by (B) below:

(A) The Single-Sum Amount determined as if the Participant survived to his fiftieth ($50^{th}$) birthday and Separated from Service.

(B) The sum of one (1) plus the Discount Rate raised to a power equal to the number of years and months between the first of the second month following the Participant's 50 th birthday and the first of the month following the Participant's date of death.

(4) If a Pre-2016 Participant or a 2016 Participant who first participates in the Plan on or after January 1, 2018 or is rehired on or after January 1, 2018, dies while in active service and prior to age 50, the Single-Sum Amount described in Section 5.2(f)(1) above is calculated as the actuarial present value of the Pension Benefit payable as a single life annuity calculated using the Discount Rate and the "Applicable Mortality Table" within the meaning of Code Section 417(e)(3) described by the Secretary of the Treasury for the calendar year in which the Participant Separates from Service. This Single-Sum Amount calculation shall be determined as of the first of the month following the Participant's date of death taking into account the following: (a) no reductions are applied for the Death Benefit Charge-Basic or the Death Benefit Charge-Enhanced for preretirement death benefit coverage under the Pension Plan; and (b) the actuarial present value calculation reflects a deferred factor to the first of the month coincident with or following the Participant's age 50; and (c) the Pension Benefit is payable at the first of the month coincident with or following the Participant's age 50.

(5) If a Pre-2016 Participant or a 2016 Participant who first participates in the Plan on or after January 1, 2018 or is rehired on or after January 1, 2018, dies while in active service at age 50 or later, the Single-Sum Amount described in Section 5.2(f)(1) above is calculated as the Single-Sum Amount described in Section 2.34(b)(1).

(6) If a Pre-2016 Participant or a 2016 Participant who first participates in the Plan before January 1, 2018 and is not rehired on or after January 1, 2018, dies after Separation from Service but prior to payment in accordance with Section 5.2(e)(1) above, the Single-Sum Amount described in Section 5.2(f)(1) above is calculated as (A) divided by (B) below:

(A) The Single-Sum Amount determined as if the Participant's first installment date was to be coincident with his Normal Retirement Date.

(B) The sum of one (1) plus the Discount Rate raised to a power equal to the number of years and months between the Participant's Normal Retirement Date and the first of the month following the Participant's date of death.

(7) If a Pre-2016 Participant or a 2016 Participant who first participates in the Plan after January 1, 2018 or is rehired on or after January 1, 2018, dies after Separation from Service but prior to payment in accordance with Section 5.2(e)(1) above, the Single-Sum Amount described in Section 5.2(f)(1) above is calculated as the actuarial present value of the Pension Benefit payable as a single life annuity calculated using the Discount Rate and the "Applicable

Mortality Table" within the meaning of Code Section 417(e)(3) described by the Secretary of the Treasury for the calendar year in which the Participant Separates from Service. This Single-Sum Amount calculation shall be determined as of the first of the month following the Participant's date of death taking into account the following: (a) no reductions are applied for the Death Benefit Charge-Basic or the Death Benefit Charge-Enhanced for preretirement death benefit coverage under the Pension Plan; and (b) the actuarial present value calculation reflects a deferred to Normal Retirement Date factor; and (c) the Pension Benefit is payable at the Participant's Normal Retirement Date.

With respect to Section 5.2(f)(1) above, for the avoidance of doubt, the Participant may either elect his Spouse as his sole Designated Beneficiary or may elect Designated Beneficiary(ies) none of which is the Spouse.

**7.**

The Plan is hereby amended by adding a new Section 5.11, to read as follows:

5.11 Provisions Related to the AGL Resources Inc. Excess Plan

(a) Merger. Effective January 1, 2018, the AGL Resources Inc. Excess Plan (the "Gas Excess Plan") will be merged with and into the Plan. Except as otherwise provided in this Section, the benefits transferred from the Gas Excess Plan to the Plan will be considered Pension Benefits hereunder and will be subject to all of the provisions of the Plan related to Pension Benefits.

(b) Eligibility. Each individual who had an accrued benefit under the Gas Excess Plan as of December 31, 2017, will become a Participant in the Plan effective January 1, 2018, with respect to such accrued benefit. However, such individual's eligibility to actively participate in the Plan on and after January 1, 2018, will be determined by the eligibility provisions of the Plan.

(c) Distributions. The payment of benefits for any Participant who had an accrued benefit under the Gas Excess Plan as of December 31, 2017, will be governed by the payment provisions of the Gas Excess Plan, including but not limited to (i) provisions regarding the timing and form of payment following separation from service, (ii) the definition of separation from service, (iii) application of the 6-month delay to key employees, (iv) mandatory cashouts, and(v) preretirement survivor benefits. Provisions in the Plan related to payment timing upon a change in control will not apply to such Participants.

**8.**

Appendix A of the Plan is hereby amended by deleting it in its entirety and replacing it with the following:

**APPENDIX A**

**THE SOUTHERN COMPANY SUPPLEMENTAL BENEFIT PLAN**
**EMPLOYING COMPANIES AS OF JANUARY 1, 2018**

Alabama Power Company
Georgia Power Company
Gulf Power Company
Mississippi Power Company
Southern Communications Services, Inc.
Southern Company Energy Solutions, LLC
Southern Company Gas and its affiliated companies
Southern Company Services, Inc.
Southern Nuclear Operating Company, Inc.
Southern Power Company

**9.**

Except as amended herein by this Second Amendment, the Plan shall remain in full force and effect.

IN WITNESS WHEREOF, the Company, through its duly authorized officer, has adopted this Second Amendment to the Southern Company Supplemental Benefit Plan, as amended and restated as of June 30, 2016, this 12th day of December, 2017.

**SOUTHERN COMPANY SERVICES, INC.**

| | |
|---|---|
| By: | /s/Nancy E. Sykes |
| Name: | Nancy E. Sykes |
| Its: | EVP & Chief Human Resources Officer |

Exhibit 10(c)8

Georgia Power Company has requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the Securities and Exchange Commission. Georgia Power Company has omitted such portions from this filing and filed them separately with the Securities and Exchange Commission. Such omissions are designated as “[***].”

# CONSTRUCTION COMPLETION AGREEMENT

**BETWEEN**

**GEORGIA POWER COMPANY, FOR ITSELF AND AS AGENT FOR OGLETHORPE POWER CORPORATION (AN ELECTRIC MEMBERSHIP CORPORATION), MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA, MEAG POWER SPVJ, LLC, MEAG POWER SPVM, LLC, MEAG POWER SPVP, LLC, AND THE CITY OF DALTON, GEORGIA, ACTING BY AND THROUGH ITS BOARD OF WATER, LIGHT AND SINKING FUND COMMISSIONERS, AS OWNERS**

**AND**

**BECHTEL POWER CORPORATION**

**DATED AS OF OCTOBER 23, 2017**

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## EXHIBITS

# CONSTRUCTION COMPLETION AGREEMENT

This CONSTRUCTION COMPLETION AGREEMENT ("Agreement") is entered into as of the 23 rd day of October, 2017 ("Effective Date"), by and between GEORGIA POWER COMPANY, a Georgia corporation ("GPC"), acting for itself and as agent for OGLETHORPE POWER CORPORATION (AN ELECTRIC MEMBERSHIP CORPORATION), an electric membership corporation formed under the laws of the State of Georgia, MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA, a public body corporate and politic and an instrumentality of the State of Georgia, MEAG POWER SPVJ, LLC, MEAG POWER SPVM, LLC, MEAG POWER SPVP, LLC, each a Georgia limited liability company, and THE CITY OF DALTON, GEORGIA, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light and Sinking Fund Commissioners (collectively, the "Owners"); and BECHTEL POWER CORPORATION, a Nevada corporation ("Contractor"). Owners and Contractor may be referred to individually as a "Party" and collectively as the "Parties".

## RECITALS

WHEREAS, Owners are presently developing and constructing two new nuclear plant units and related facilities, structures and improvements at the Vogtle plant site in Georgia, which units are designated as Vogtle Units 3 and 4;

WHEREAS, Contractor is engaged in the business of providing services for the construction of power generation facilities;

WHEREAS, Owners and Contractor desire to enter into this Agreement in order for Contractor to provide certain services in order for Owners to complete the construction of the Vogtle Units 3 and 4, pursuant to the terms and conditions set forth herein.

NOW, THEREFORE, in consideration of the recitals, the mutual promises herein and other good and valuable consideration, the receipt and sufficiency of which the Parties acknowledge, the Parties, intending to be legally bound, stipulate and agree as follows:

1.1 Defined Terms . For purposes of this Agreement, the following words and expressions shall have the meanings hereby assigned to them, except where the context clearly indicates a different meaning is intended.

" Abandon " or " Abandonment " means conduct by Contractor inconsistent with continued performance of Contractor's obligations under this Agreement from which it would be reasonable to conclude that Contractor has decided to discontinue indefinitely performance of the Work, provided that Abandon shall not include stopping or suspending performance of the Work where: (i) continued performance of the Work is prevented by a Force Majeure Event, or (ii) Contractor is otherwise entitled to suspend performance of the Work under this Agreement.

" Adjustment Event " means each of the following, but (except with respect to subpart (xiv) below) only to the extent not attributable to the acts or omissions of Contractor, any of its Subcontractors, any Contractor-Managed Subcontractor or their respective Personnel, or breach of this Agreement by Contractor or any Subcontractor, and only to the extent material:

(i) An Owner Directed Change

(ii) Provision of an Issued for Construction Document to Contractor or a Contractor-Managed Subcontractor later than the later of: (a) the date (if any) indicated in the Baseline Schedule for provision of such Issued for Construction Document and (b) the time required to support Contractor's performance of the Work or the Contractor-Managed Subcontractor's performance of its work, in accordance with the Baseline Schedule;

(iii) Provision of an Issued for Construction Document to Contractor or a Contractor-Managed Subcontractor (or a change, modification or revision thereto) which necessitates (x) change(s) to Contractor's planned sequence of construction activities as shown in the Baseline Schedule or (y) change(s) to Contractor's planned construction methodology as documented by previous Monthly Status Reports or similar reports previously provided by Contractor to Owners (e.g., required use of additional large crane) or (z) rework of construction work previously performed;

(iv) The provision of Plant Equipment and Materials to Contractor or a Contractor-Managed Subcontractor later than the later of: (a) the date (if any) indicated in the Baseline Schedule for provision of such Plant Equipment and Materials, and (b) the date required to support Contractor's performance of the Work or the Contractor-Managed Subcontractor's performance of its work, in accordance with the Baseline Schedule;

(v) Delay or failure by Owners to perform their obligations under this Agreement by the later of: (a) the dates indicated in the Baseline Schedule, and (b) the date required to support Contractor's performance of the Work or a Contractor-Managed Subcontractor' performance of its work, in accordance with the Baseline Schedule;

(vi) Delay by Owner-Managed Subcontractors (but not delays by Contractor-Managed Subcontractors) or delay by other contractors or suppliers for which Owners are responsible (but not delays by Contractor-Managed Subcontractors), in each case beyond the applicable date(s) required to support the Baseline Schedule;

(vii) A change in Site Rules, policies, procedures or other Site-related requirements that materially impact or affect the Work, which are issued by or on behalf of Owners after the Effective Date;

(viii) A Force Majeure Event;

(ix) Subject to Section 12.1.1, a Change in Law to the extent that Contractor or a Contractor-Managed Subcontractor is legally obliged to comply with such change;

(x) A deviation from a Target Assumption set forth in Exhibit B;

(xi) Suspension of performance of the Work pursuant to Section 2.13.5, Section 8.6 or Section 21.1;

(xii) Defects in work performed by others prior to the Effective Date that are discovered following the Effective Date; provided that such an Adjustment Event shall not result in an adjustment to the Target Construction Cost and the costs resulting from such an Adjustment Event shall be treated as Excluded Costs;

(xiii) The denial by Owners of a requested deviation requiring the use of Contingency funds under Section 2.21.2(iii), unless Contractor proceeds with implementation of the deviation notwithstanding Owners' denial; and

(xiv) The incurrence of costs by Contractor pursuant to Section 10.4.2 or Section 11.4.2 in order to mitigate the effects of an Adjustment Event set forth in subparts (i) through (xiii) above).

" AEA " means the Atomic Energy Act of 1954, 42 U.S.C. § 2011 et seq.

" Affected Party " has the meaning set forth in Section 13.1.

" Affiliate " means, with respect to any Party, any other Person that, as of the Effective Date or at any time thereafter, (a) owns or controls, directly or indirectly, the Party, (b) is owned or controlled by the Party, or (c) is under common ownership or control with the Party, where "own" means ownership of fifty percent (50%) or more of the equity interests or rights to distributions on account of equity of the Party and "control" means the power to direct the management or policies of the Party, whether through the ownership of voting securities, by contract, or otherwise.

" Affiliate Subcontractor " means a Subcontractor that is an Affiliate of Contractor, including Richmond, BEO and Custom Arc Services, Inc.

" Affiliate Subcontractor Claim " means a Claim made by an Affiliate Subcontractor and all damages, liabilities, losses, penalties, costs and expenses (including attorneys' fees) related thereto.

" Agreement " has the meaning set forth in the first paragraph above and shall include all Exhibits and amendments hereto, including Change Orders.

" Agency Agreements " means: (i) the Ownership Agreement, (ii) that certain letter dated July 28, 2006 entitled "Designation of Southern Nuclear Operating Company, Inc. as Agent for Georgia Power Company Under the Vogtle Additional Units Development Agreement," as amended by any amendments that are provided to Contractor; and (iii) that certain July 30, 2008 letter entitled

"Designation of Southern Nuclear Operating Company, Inc. ("Southern Nuclear" or "SNC"), as Agent for Georgia Power Company ("Georgia Power" or "GPC") under the Vogtle Additional Units Ownership Agreement for Contract Management and Construction Services," as amended by any amendments that are provided to Contractor.

" Amended and Restated Staff Augmentation Agreement " means the staff augmentation agreement signed by the Parties as of the Effective Date.

" Applicable Law Compliant " has the meaning set forth in Section 12.1.2.

" ASME " means the American Society of Mechanical Engineers.

" Base Fee " has the meaning set forth in Section 7.2.

" Baseline Schedule " means the Primavera P6 file set forth in Exhibit C, as it may be modified pursuant to this Agreement.

" BEO " has the meaning set forth in Section 2.17.2.

" Branch Technical Position " means a final report prepared by NRC staff setting forth recommendations or a method the staff considers acceptable for performing analyses, calculations, or other technical evaluations that are used to satisfy or to evaluate or demonstrate compliance with NRC regulatory requirements. Each Branch Technical Position purports to be a Branch Technical Position on its face or is identified by a number that includes the designator BTP (e.g., BTP 8-n).

" Bulletin " means a final document produced by the NRC that (i) requests licensee actions and/or information to address significant issues regarding matters of safety, security, safeguards, or environmental significance that have great urgency, and (ii) requires a written response. Each Bulletin is identified by a number that includes the designator BL and a reference to the year of issuance (e.g., BL-15-nn).

" Business Day " means every Day other than Saturday, Sunday or a legal holiday recognized by the State of Georgia.

" CAS " means Custom Arc Services, Inc.

" Cash Security " means cash security, free and clear of any adverse Lien or interest, provided pursuant to a pledge agreement and a control agreement, each in a form and substance acceptable to the Party to whom such security is being provided.

" Change Order " means a change to the scope of Work or the terms of this Agreement (including an adjustment to the Target Construction Cost or Target Completion Dates) agreed upon and executed in writing by the Parties.

" Change in Law " means (a) the adoption or change, after the Effective Date, of or in the judicial or administrative interpretation of any Laws (excluding any Laws relating to net income Taxes), which is inconsistent or at variance with any Laws in effect prior to the Effective Date, (b) the imposition after the Effective Date of any requirement for a new Government Approval, or (c) the imposition by a Government Authority after the Effective Date of any condition or requirement (except to the extent that any conditions or requirements result from the acts or omissions of Contractor or a Subcontractor) not required as of the Effective Date on or with respect to the issuance, renewal or extension of a Government Approval. Notwithstanding the foregoing definition of "Change in Law," (i) where the NRC is the involved Government Authority, only (A) statutes that are duly enacted and (B) final and official versions of NRC Regulations, Regulatory Guides, NUREGs, Branch Technical Positions, Standard Review Plans, Interim Staff Guidance, Bulletins, Orders, and written directives, and revisions thereto, in which NRC acknowledges a new regulatory requirement or a change in an existing requirement, and that are officially promulgated or issued subsequent to the Effective Date, shall be considered a "Change in Law" under this Agreement and shall be specifically referred to herein as an "NRC Change in Law"; and (ii) any change in Law that occurs before the Effective Date but which goes into force and effect after the Effective Date will not be a Change in Law.

" Claim " means a claim, demand, cause of action of any kind and character, and all damages, liabilities, losses, penalties, costs and expenses (including attorneys' fees) related thereto.

" Combined Construction Costs " means the sum of:

(i) all Reimbursable Costs paid by Owners on or after the Effective Date until Final Completion, except for: (a) costs relating to Commissioning and Startup Support, (b) Excluded Costs as identified on Exhibit M, and (c) costs disputed by Owners that are refunded by Contractor or which are withheld by Owners; plus

(ii) all amounts paid to Contractor-Managed Subcontractors with respect to work accomplished following the Effective Date until Final Completion, excluding (a) Excluded Costs as identified on Exhibit M, and (b) amounts recovered by Owners from Contractor-Managed Subcontractors.

" Commercial Operation Date " means, with respect to a given Unit, the Day on which Owners' testing and commissioning of such Unit are complete and Owners have declared that such Unit is ready for commercial operations.

" Commissioning and Startup Support" has the meaning set forth in Section 2.10.

" Contingency " means the amount included within the Target Construction Cost set forth in Exhibit M and which is indicated as contingency.

" Construction Equipment " means equipment, machinery, temporary facilities and/or test equipment used in the performance of the Work and which will not become a permanent part of the Facility.

" Construction Materials " means construction materials, tools and consumable items used in the performance of the Work and which will not become a permanent part of the Facility.

" Construction Site " means the areas where the Work will be performed at the Vogtle Electric Generation Plant and construction laydown areas, all as described in Exhibit D. The term "Construction Site" shall not include those areas dedicated solely to VEGP Units 1 and 2, except to the extent such portions are needed for access, ingress, egress, or will otherwise be impacted by the construction or operation of the Facility.

" Contract Claim " has the meaning set forth in Section 38.1.

" Contractor " has the meaning set forth in the opening paragraph of this Agreement.

" Contractor Event of Default " has the meaning set forth in Section 21.2.1.

" Contractor Guarantor " shall have the meaning set forth in Section 19.1.1.

" Contractor Interests " means Contractor and its Affiliates (including Richmond) and their respective directors, officers, employees, agents, shareholders and members (provided with respect to Williams Plant Services, LLC, the term "member" refers to and is limited to its ownership interest in Richmond).

" Contractor-Managed Subcontract " means those subcontracts entered into by Owners (or assigned to and accepted by Owners) that correspond to Contractor-Managed Subcontract Scope as identified in Exhibit E and which are to be managed and administered by Contractor as described in Section 3.3.

" Contractor-Managed Subcontractor " means a subcontractor under a Contractor-Managed Subcontract.

" Contractor-Managed Subcontract Scope " means the construction-related scope (including scopes of supply) as identified in Exhibit E, to be performed under Contractor-Managed Subcontracts, subject to a Contractor determination, in consultation with Owners as part of the Subcontract Scope Alignment Process, to perform such scope in another manner.

" Contractor's Authorized Representative " means the Person whom Contractor designates in writing to act on behalf of Contractor under this Agreement.

" Contractor's Government Approvals " means the construction license(s) and any other Government Approval required to be obtained by Contractor to perform the Work.

" Contractor's Quality Assurance Program " has the meaning set forth in Section 5.1.1.

" Contractor Trend Program " has the meaning set forth in Section 2.21.1.

" Core Scope " has the meaning set forth in Exhibit A.

" Cost Earned Fee " has the meaning set forth in Section 7.2(iv).

" Cumulative Final Completion Percentage " means, as of a given date, the combined cumulative construction completion percentage of the Work and Contractor-Managed Subcontractor work tied to achievement of Final Completion that has been completed under this Agreement as of such date, as determined by reference to the percentage completion methodology agreed by the Parties.

" Cumulative Mechanical Completion Percentage " means, as of a given date with respect to a given Unit, the combined cumulative construction completion percentage of the Work and Contractor-Managed Subcontract work tied to achievement of Mechanical Completion for such Unit that has been completed under this Agreement as of such date, as determined by reference to the percentage completion methodology agreed by the Parties.

" Dalton Utilities " has the meaning set forth in Section 18.3.1.

" Dalton Utilities Assets " has the meaning set forth in Section 18.3.1.

" Day " means a calendar day.

" Days Away From Work Rate " has the meaning set forth in Section 2.17.4.

" Deadband Amount " has the meaning set forth in Section 7.4.1.

" Defects Subcap " has the meaning set forth in Section 15.6.

" Design Authority " means the organization having responsibility for maintaining the Design Basis and ensuring that design output documents accurately reflect the Design Basis. Unless Owners otherwise notify Contractor in writing, Design Authority as used herein refers to Westinghouse.

" Design Basis " shall have the meaning ascribed to it in 10 C.F.R. § 50.2.

" Designated Persons " has the meaning set forth in Section 4.2.1.

" Development Agreement " means that certain Plant Vogtle Owners Agreement between the Owners dated May 31, 2008 authorizing development, construction, licensing and operation of additional generating units.

" DOE " means the U.S. Department of Energy.

" DOR " means the division of responsibilities between Owners and Contractor as set forth in Exhibit A.

" DRB " has the meaning set forth in Section 38.2.

" DRB Procedures " means the procedures set forth in Exhibit U.

" Early Completion Targets " has the meaning set forth in Section 9.1.

" Earned Fee " has the meaning set forth in Section 7.2.

" Effective Date " has the meaning set forth in the first paragraph of this Agreement.

" Eligible Letter of Credit " means one or more irrevocable standby letters of credit in substantially the form of Exhibit F (for the Repayment Letter of Credit) or Exhibit F (for an Owner Letter of Credit) (or such other form of irrevocable standby letter of credit as may reasonably acceptable to the Party to whom such letter of credit is required to be provided under this Agreement), issued by: (i) a U.S. commercial bank or U.S. branch of a major foreign bank, in each case who has and maintains bank assets of at least Ten Billion Dollars ($10,000,000,000) and at all times having a senior unsecured rating of A minus or higher by Moody's and A minus or higher by S&P; or (ii) in the case of OPC as the Party providing an Eligible Letter of Credit, CoBank, ACB, in each case in an amount required by the terms of this Agreement.

" Environmental Laws " means any and all statutes, laws, treaties, decrees, executive orders, rules, regulatory orders, directives, judgments, writs, approvals, ordinances, policies, regulations, interpretations and permits or other similar legal requirements as in effect, and as may be amended during the term of this Agreement, of a court, arbitrator, or governmental or political agency, body, or instrumentality with jurisdiction over a Party, the Facility or any Hazardous Materials connected with the Work, relating or applicable to pollution, protection of the environment, and health and safety issues, and including Releases or threatened Releases of Hazardous Materials, Remediation due to Hazardous Materials, the manufacturing, generation, use, processing, treatment, recycling, storage, handling and disposal of Hazardous Materials, human or natural exposure to Hazardous Materials, and interference with the use of property caused by or resulting from Hazardous Materials. Environmental Laws include without limitation the Comprehensive Environmental Response, Compensation, and Liability Act, 42 U.S.C. Section 9601 et seq.; the Federal Insecticide, Fungicide and Rodenticide Act, 7 U.S.C. Section 136 et seq.; the Resource Conservation and Recovery Act, 42 U.S.C. Section 6901, et seq.; the Toxic Substances Control Act, 15 U.S.C. Section 2601 et seq.; the Clean Air Act, 42 U.S.C. Section 7401 et seq.; the Federal Water Pollution Control Act, 33 U.S.C. Section 1251 et seq.; the Oil Pollution Act, 33 U.S.C. Section 2701 et seq.; the Endangered Species Act, 16 U.S.C. Section 1531 et seq.; the National Environmental Policy Act, 42 U.S.C. Section 4321, et seq.; the Occupational Safety and Health Act, 29 U.S.C. Section 651 et seq. (to the extent relating to human exposure to Hazardous Materials); the Homeland Security Appropriations Act of 2007, 109 P.L. 295; 120 Stat. 1355 (to the extent relating to the security of Hazardous Materials); the Hazardous Materials Transportation Act, 49 U.S.C. Section 1801, et seq., the Safe Drinking Water Act, 42 U.S.C. Section 300f et seq.; Emergency Planning and Community Right- to-Know Act, 42 U.S.C. Section 11001 et seq.; Atomic Energy Act, 42 U.S.C. Section 2014 et seq.; Nuclear Waste Policy Act, 42 U.S.C. Section 10101 et seq.; and their state, tribal and local counterparts or equivalents and regulations issued pursuant to any of those statutes.

" EPA Identification Number " means the identification number from the U.S. Environmental Protection Agency after notification to EPA from a hazardous waste generator by EPA Form 8700-12.

" Excluded Costs " has the meaning set forth in Exhibit M.

" Exhibit " means each one of the documents Exhibits A through V annexed to this Agreement, which are hereby incorporated into and made a part of this Agreement.

"Experience Modification Ratio" has the meaning set forth in Section 2.17.4.

"FFD" has the meaning set forth in Section 30.1.

"Facility" means Unit 3, Unit 4 and the Shared Facilities.

"Fee" means Two Hundred Forty Million Dollars ($240,000,000), subject to adjustment as provided in Section 3.2.3 and otherwise as provided in this Agreement.

"Final Completion" means both Units have achieved Mechanical Completion and all of the Work (other than Commissioning and Startup Support) is otherwise complete.

"Final Payment Invoice" has the meaning set forth in Section 8.8.1.

"Financing Parties" means the lenders and financing institutions providing construction, interim and/or long-term financing for the Facility or any portion thereof, including any financing in the form of a synthetic lease or leveraged lease, and their assigns and a trustee or agent acting on behalf of the lenders or financing institutions. DOE, in its capacity as a guarantor of any indebtedness issued by any Owner, and any trustee or agent acting on behalf of the DOE, shall be deemed "Financing Parties."

"Fitch Ratings" means Fitch Ratings Ltd.

"Force Majeure Event" has the meaning set forth in Article 13.

"Georgia PSC" means the Georgia Public Service Commission.

"GPC" has the meaning set forth in the opening paragraph of this Agreement.

"Government Approval" means an authorization, consent, approval, clearance, license, ruling, permit, tariff, certification, exemption, filing, variance, order, judgment, no-action or no- objection certificate, certificate, decree, decision, declaration or publication of, notices to, confirmation or exemption from, or registration by or with a Government Authority relating to the design, engineering, procurement, installation, construction, testing, start-up, financing, completion, ownership, operation or maintenance of the Facility.

"Government Authority" means a federal, state, county, city, local, municipal, foreign or other government or quasi-government authority or a department, agency, subdivision, court or other tribunal of any of the foregoing that has jurisdiction over Owners, Contractor, the Facility or the activities that are the subject of this Agreement.

"Hazardous Materials" means any and all chemicals, constituents, contaminants, pollutants, materials (including but not limited to petroleum or petroleum products), and wastes and any other carcinogenic, corrosive, ignitable, radioactive, reactive, toxic or otherwise hazardous substances, mixtures (whether solids, liquids, gases), daughter or degradation products or any similar substances now or at any time subject to regulation, control, remediation or otherwise addressed under Environmental Laws or considered to be hazardous or otherwise harmful to human health or the environment under such Environmental Laws and shall include those substances defined as a "source", "special nuclear" or "by-product" material pursuant to Section 10 of the AEA (42 U.S.C. § 2014 et seq .) and those substances defined as "residual radioactive material" in Section 101 of the Uranium Mill Tailings Radiation Control Act of 1978 (42 U.S.C. §§ 7901 et seq .).

" Increase Trigger Amount " has the meaning set forth in Section 7.4.2.

" Independent Engineer " means, if required by the Georgia PSC, Financing Parties or otherwise, a nationally recognized independent engineering firm(s), that is not an Affiliate of Owners or Contractor or a competitor of Owners or Contractor in the nuclear power plant market. As of the Effective Date, an Independent Engineer has been designated by the Georgia PSC. Any other Independent Engineer designated by the Financing Parties or otherwise, as applicable, shall be reasonably acceptable to Owners and Contractor.

" Initial Funding Request " has the meaning set forth in Section 8.2.1.

" Insolvent " means, with respect to a Person, that such Person shall have commenced a voluntary bankruptcy proceeding, or an involuntary bankruptcy proceeding shall have been commenced against such Person and an order for relief shall have been entered as to such involuntary bankruptcy, or there shall have been appointed a trustee or receiver for such Person or for all or a substantial part of its property, or a case or proceeding shall have been commenced by or on behalf of such Person seeking reorganization, liquidation, dissolution, winding-up or other such relief in respect of such Person under a bankruptcy, insolvency or other similar act or law of any jurisdiction.

" Interest Rate " means the Prime Rate plus two percent (2%).

" Interim Staff Guidance " means a document issued by the NRC to clarify or to address issues not discussed in a Standard Review Plan. Each Interim Staff Guidance is identified by a number including the designator ISG (e.g., DC/COL-ISG-nn).

" Invitees " means, with respect to a Person, such Personnel or other Persons as have been permitted entry onto the Construction Site by such Person.

" Issued for Construction Documents " means the detailed drawings and specifications setting forth in detail the requirements for the construction of the Facility.

" ITAAC " means the NRC inspections, tests and analyses and their associated acceptance criteria which are approved and issued for the Facility as contained in Appendix C of the COL.

" Key Personnel " has the meaning set forth in Section 2.7.1.

" Law " means (a) a constitution, statute, law, rule, regulation, code, treaty, ordinance, judgment, decree, writ, order, concession, grant, franchise, license, agreement, directive, guideline, policy, requirement, including without limitation Environmental Laws, or other governmental restriction or any similar form of decision of or determination by, or any binding interpretation or administration of any of the foregoing by, a Government Authority, whether now or hereafter in effect, (b) requirements or conditions on or with respect to the issuance, maintenance or renewal of a Government Approval or applications therefor, whether now or hereafter in effect, to the extent relevant to the Work, and (c) the Licensing Basis.

" Licensed Operator " has the meaning set forth in Section 4.1.1.

" Licensing Basis " means the ITAAC, combined licenses for each of Unit 3 and Unit 4 (NRC License Nos. NPF-91 and NPF-92, collectively referred to as "COL"), and other NRC rules, regulations, and requirements applicable to the Facility, including without limitation the current version of the Updated Final Safety Analysis Report as maintained by Owners pursuant to 10 C.F.R. § 50.71 and other Law ("UFSAR"), licensee's written commitments for ensuring compliance with and operation within applicable NRC requirements and the Facility-specific Design Bases (including without limitation all modifications and additions to such commitments that are docketed and in effect over the term of the COL).

" Lien " means a lien, mortgage, pledge, encumbrance, charge, security interest, option, right of first refusal, other defect in title or other restriction of any kind or nature.

" Loan Guaranty Agreements " means the respective Loan Guarantee Agreements between the U.S. Department of Energy, as guarantor, and MEAG, OPC, and GPC, respecting the Facility.

" Material Safety Data Sheets " are those sheets described in Section 2.13.1.

" MEAG " means the Municipal Electric Authority of Georgia.

" Mechanical Completion " has the meaning set forth in Exhibit G.

" Mechanical Completion Date " means, with respect to a given Unit, the Day on which such Unit achieves Mechanical Completion.

" Monthly Funding Period " has the meaning set forth in Section 8.2.1.

" Monthly Funding Request " has the meaning set forth in Section 8.2.1.

" Monthly Status Report " has the meaning set forth in Section 2.3.1.

" Moody's " means Moody's Investor Services, Inc.

" Non-Core Scope " means all portions of the Work that are not Core Scope.

" Non-Reimbursable Costs " has the meaning set forth in Section 7.1.2.

" NRC " means the U.S. Nuclear Regulatory Commission and its staff.

" NRC Change in Law " shall have the meaning set forth in the definition of "Change in Law."

" NRC Regulations " means those regulations promulgated by the NRC appearing in Title 10 of the Code of Federal Regulations.

“ Nuclear Incident ” means any occurrence that causes bodily injury, sickness, disease or death, or loss of or damage to property, or loss of use of property, arising out of or resulting from the radioactive, toxic, explosive, or other hazardous properties of source material, special nuclear material, or by-product material which is used in connection with the operation of the Facility. “Source material”, “special nuclear material”, and “by-product material”, as applicable to this Agreement shall have those meanings assigned by the AEA.

“ NUREG ” means reports or brochures, produced by the NRC, on regulatory decisions, results of research, results of incident investigations, and other technical and administrative information. Each NUREG is identified by a number including the designator NUREG (e.g., NUREG-nnnn).

“ OPC ” means Oglethorpe Power Corporation (An Electric Membership Corporation).

“ Orde r” means a document issued by the NRC, which is styled as or purports to be an “Order” on its face and satisfies one or more of the following: (i) is published or noticed in the Federal Register; (ii) is issued by the NRC Commission, including identification by a number with the designator CLI (e.g., CLI-15-nn); (iii) is issued by an NRC Atomic Safety and Licensing Board, including identification by a number with the designator LBP (e.g., LBP-15-nn), as part of an adjudicatory proceeding; or (iii) is issued pursuant to the NRC’s enforcement authority, including identification by a number with the designator EA (e.g., EA-15-nnn).

“ OSHA ” means the Occupation Safety and Health Administration.

“ Other Lead Personnel ” has the meaning set forth in Section 2.7.2.

“ Owner Controlled Insurance Program ” or “ OCIP ” has the meaning set forth in Section 17.1.3.

“ Owner Directed Change ” has the meaning set forth in Section 12.1.

“ Owner-Managed Subcontracts ” has the meaning set forth in Section 3.1.

“ Owner-Managed Subcontractors ” has the meaning set forth in Section 3.1.

“ Owners ” means all of GPC, Oglethorpe Power Corporation (An Electric Membership Corporation), the Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and Dalton Utilities; provided that GPC has been appointed as agent for Oglethorpe Power Corporation (An Electric Membership Corporation), the Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and Dalton Utilities as set forth in Section 18.3.1.

“ Owner ” means any one of the Owners individually.

“ Owner Security ” has the meaning set forth in Section 19.2.1.

“ Owner Security Amount ” means [***].

“ Owners’ Authorized Representative ” has the meaning set forth in Section 4.1.2.

" Owners Event of Default " has the meaning set forth in Section 21.5.1.

" Owners' Government Approvals " means the Government Approvals required to be obtained by Owners with respect to the Facility.

" Owners' Interests " means Owners and their respective members and Affiliates, and their respective directors, officers, shareholders, employees, agents and lenders.

" Ownership Agreement " means that certain Plant Alvin W. Vogtle Additional Units Ownership Participation Agreement among the Owners, dated as of April 21, 2006, as amended by that certain Amendment No. 1 and Amendment No. 2 to such agreement, and any subsequent amendments that are provided to Contractor.

" Ownership Interest " means the respective percentage ownership interest of an Owner in the Facility as determined from time to time pursuant to the Ownership Agreement, provided that any changes to such ownership interests after the Effective Date will have no effect for the purposes of this Agreement until notice of such change is given to Contractor.

" Parent Company Guarantee " has the meaning set forth in Section 19.1.1.

" Party " and " Parties " has the meaning set forth in the opening paragraph of this Agreement.

" Performance Standards " has the meaning set forth in Section 2.6.

" Permitted Purpose " has the meaning set forth in Section 22.2.2.

" Person " means an individual, corporation, company, partnership, joint venture, association, trust, unincorporated organization or Government Authority.

" Personnel " means, with respect to a Person, such Person's employees, officers, directors, agents, personnel, and representatives, excluding personnel seconded by a Party to a Party.

" Plant Equipment and Materials " means all materials, supplies, apparatus, devices, machinery, vehicles, equipment, parts, components, instruments, appliances, computer hardware and associated software and appurtenances thereto and items of any kind that are or will be permanently incorporated into the Facility.

" Power Revenue Bond Resolution " means the Power Revenue Bond Resolution adopted by the Municipal Electric Authority of Georgia on August 30, 1976 that, as amended, restated and supplemented, authorizes the issuance of both senior lien bonds and subordinated lien bonds for the purpose of financing the Municipal Electric Authority of Georgia's "Project One" facilities.

" Prime Rate " means, as of a particular date, the prime rate of interest as published on that date in The Wall Street Journal, and generally defined therein as "the base rate on corporate loans posted by at least 75% of the nation's 30 largest banks." If The Wall Street Journal is not published on a date for which the interest rate must be determined, the prime interest rate shall be the prime rate published in The Wall Street Journal on the nearest-preceding date on which The Wall Street Journal was published. If The Wall Street Journal discontinues publishing a prime rate, the prime interest rate shall be the prime rate announced publicly from time to time by Bank of America, N.A. or its successor.

"Project Corrective Action Program" or "Project CAP" means measures established by Owners to assure that conditions adverse to quality, including, failures, malfunctions, deficiencies, deviations, defective Plant Equipment and Materials, and non-conformances are promptly identified and corrected. The measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition.

"Project Cost Forecast" means, at any given time, the then-current projection of total Combined Construction Costs provided by Contractor, which has been evaluated and reported by Owners' project control program.

"Project Employee Concerns Program" or "Project ECP" has the meaning set forth in Section 31.3.

"Project Schedule" means the working schedule utilized by the Parties for the performance of the Work and for the Owner activities required to support performance of the Work, as described in Article 9. The version of the Project Schedule in effect as of the Effective Date is the Baseline Schedule.

"Promptly" has the meaning set forth in Section 15.2.3.

"Property Tax" has the meaning set forth in Section 37.2.1.

"Protected Information" has the meaning set forth in Section 22.1.

"Prudent Practices" means the standards, practices and methods conforming to Law and that degree of skill and diligence that would reasonably be expected from a skilled and experienced contractor, as the case may be, engaged in the construction of nuclear power plants, and other large industrial construction projects in the United States. Prudent Practices are not limited to optimum practices or methods to the exclusion of others, but rather refer to a reasonable range of commonly used and reasonable practices and methods.

"Punch List" has the meaning set forth in Section 14.3.

"Ready for Fuel Load Date" means, with respect to a Unit, the date on which Owners have received all Government Approvals required, and have determined that all regulatory, safety and technical requirements have been satisfied, in order to commence the loading of nuclear fuel into such Unit.

"Recordable Case Incidence Rate" has the meaning set forth in Section 2.17.4.

"Reduction Trigger Amount" has the meaning set forth in Section 7.4.1.

"Regulatory Guide" means a document produced by the NRC that provides guidance to licensees and applicants on implementing specific parts of the NRC's regulations, techniques used by the NRC staff in evaluating specific problems or postulated accidents, and data needed by the NRC staff in its review of applications for permits or licenses. Each Regulatory Guide is identified by a number composed of the regulatory guide designator (RG), followed by a division number, a period, and a sequential guide number (e.g., RG 1.25).

" Release " means spilling, leaking, pumping, pouring, emitting, discharging, injecting, escaping, leaching, dumping, exacerbating, aggravating, abandoning or disposing into or migration within the environment.

" Reimbursable Costs " has the meaning set forth in Section 7.1.1.

" Remediation " means the investigation, removal, remediation and cleanup of, and other corrective action for, Hazardous Materials and/or damage to the environment caused by Hazardous Materials, including a Release thereof.

" Repayment Letter of Credit " has the meaning set forth in Section 8.7.5.

" Richmond " has the meaning set forth in Section 2.17.1.

" Safety Manual " has the meaning set forth in Section 2.15.2.

" S&P " means Standard and Poor's Rating Group.

" Sales Tax " means sales, use or similar transactional tax imposed by any Taxing Authority on Contractor, a Subcontractor, or Owners with respect to the transfer of tangible personal property or the provision of services pursuant to the Work.

" SCWE " has the meaning set forth in Section 31.2.

" Schedule Contingency " has the meaning set forth in Section 9.1.

" Schedule Earned Fee " has the meaning set forth in Section 7.2(iii).

" Section 12.1.2 Notice " has the meaning set forth in Section 12.1.2.

" Security Posting Condition " means a condition whereby the credit rating of (A) the senior unsecured debt (or issuer rating in the absence of a senior unsecured debt rating) of GPC, (B) the senior unenhanced debt of Dalton Utilities, (C) the senior unenhanced secured debt of Oglethorpe Power Corporation or (D) the senior unenhanced global scale rating to municipal obligations or equivalent rating scale of the Municipal Electric Authority of Georgia issued with respect to the Power Revenue Bond Resolution falls below any two of the following (or, if only rated by two of the following, falls below either, or, if only rated by one of the following, falls below such rating) or in the event that such Owner no longer has a credit rating from any of the following: (x) Baa3 by Moody's (if rated by Moody's), (y) BBB minus by S&P (if rated by S&P) or (z) BBB minus by Fitch Ratings (if rated by Fitch Ratings).

" Shared Facilities " means those systems, structures and components that will be utilized by both Units.

"Significant Construction Defect" means a construction defect meeting each of the following requirements:

(a) a defect in Work performed by Contractor or its Subcontractors, including Richmond, but not a defect in work performed by Contractor-Managed Subcontractors;

(b) the defect involves a situation where the physical construction deviates from the Performance Standards;

(c) the defect resulted from a programmatic failure by Contractor or its Subcontractor to comply with project processes and procedures in the performance of the Work. The foregoing is not intended to include a one-time or an isolated non-compliance or consequence, such as an instance of human error, which may result in a requirement for Contractor or its Subcontractor to remedy a defect. The foregoing is intended to include instances where multiple barriers or controls are not properly implemented or followed by Contractor or its Subcontractor, resulting in a defect which is required to be remedied; and

(d) the cumulative aggregate of costs to remedy the defect exceeds [***] .

"Site" means the premises on which the Vogtle Nuclear Generating Plant is located, including Unit Nos. 1 and 2, Unit 3 and Unit 4, including the Construction Site.

"Site Rules" has the meaning set forth in Section 28.1.

"Southern Nuclear" or "SNC" means Southern Nuclear Operating Company; provided, however, that the term "Southern Nuclear" shall also refer to any entity that is appointed by the Owners by written notice to Contractor to succeed Southern Nuclear in the performance of its functions under this Agreement.

"SNC Quality Assurance Program" has the meaning set forth in Section 5.1.3.

"Specifications" means the design and procurement specifications and drawings, and changes thereto for the design, engineering, procurement, installation and construction of the Facility.

"Standard Review Plan" means a document produced by the NRC that provides guidance to the NRC staff for reviewing an application to obtain an NRC license to construct or operate a nuclear facility or to possess or use nuclear materials.

"Subcontract" means a contract, purchase order or other writing between Contractor (or one of its Subcontractors) and a Subcontractor under which the Subcontractor performs or provides a portion of the Work.

"Subcontractor" means a Person other than Contractor performing or providing any portion of the Work on the Construction Site, hired either directly by Contractor or by a Person hired by Contractor and including every tier of subcontractors, sub-subcontractors and so forth.

" Subcontract Scope Alignment Process " means the process described in Section 3.2.2, Section 3.2.3 and Exhibit E.

" Supporting Documentation " shall have the meaning set forth in Section 8.10.

" Target Completion Date " means: (i) with respect to Unit 3, May 31, 2020; and (ii) with respect to Unit 4, May 31, 2021, in each case as such dates may be adjusted pursuant to this Agreement.

" Target Construction Cost " has the meaning set forth in Exhibit M, subject to modification as provided in this Agreement.

" Tax " or " Taxes " means all federal, state, provincial, territorial, municipal, local or foreign income, profits, franchise, gross receipts, environmental, customs, duties, net worth, sales, use, goods and services, withholding, value added, ad valorem, employment, social security, disability, occupation, pension, real property, personal property (tangible and intangible), stamp, transfer, conveyance, severance, production, excise and other taxes, withholdings, duties, levies, imposts and other similar charges and assessments (including without limitation fines, penalties and additions attributable to or otherwise imposed on or with respect to any such taxes, charges, fees, levies or other assessments, and interest thereon) imposed by or on behalf of a Taxing Authority.

" Taxing Authority " means a Government Authority exercising authority to impose, regulate, levy, assess or administer the imposition of a Tax.

" Third Party " means a Person other than Owners, Contractor and their respective Affiliates; Third Parties shall include Owners', Contractor's, and their Affiliates' respective employees, agents and personnel as well as Owners', Contractor's and their Affiliates' subcontractors and vendors of any tier.

" Third Party Claim " means a Claim made by a Third Party and all damages, liabilities, losses, penalties, costs and expenses (including attorneys' fees) related thereto.

" Trigger Date " means the Unit 3 Trigger Date or the Unit 4 Trigger Date, as determined in Section 7.3.1 and Section 7.3.3.

" Turnover Packages " means the complete work and quality control documentation in content reasonably acceptable to Owners, submitted by Contractor to Owners pursuant to Section 2.14, which demonstrates that specified Work has been sufficiently completed in accordance with this Agreement to allow turnover over to Owners and closure of related ITAACs, subject to Punch List items that Owners agree may be completed following such turnover.

" Undisputed Amount " means, with respect to a Party, either (i) an amount in respect of which such Party has not given notice to the other Party that such amount is disputed; or (ii) an amount which was so disputed by such Party but which is determined in accordance with Article 38 to be an amount that is owed to the other Party.

" Unit " means each of the nuclear plant units being constructed on the Construction Site as of the Effective Date, designated as Vogtle Electric Generating Plant Unit Nos. 3 and 4. " Unit 3 " refers to the first such Unit to achieve Mechanical Completion and " Unit 4 " refers to the second such Unit to achieve Mechanical Completion regardless of whether such Units have different numerical designations.

" Units " means both Unit 3 and Unit 4.

" Unit 3 " has the meaning set forth in the definition of "Unit" in this Article 1.

" Unit 3 Trigger Date " has the meaning set forth in Section 7.3.1.

" Unit 4 " has the meaning set forth in the definition of "Unit" in this Article 1.

" Unit 4 Trigger Date " has the meaning set forth in Section 7.3.3.

" VEGP Units 1 and 2 " means the existing Vogtle Electric Generating Plant located in Waynesboro, Georgia, designated as Units 1 and 2 as described in Nuclear Regulatory Commission License Nos. NPF-68 and NPF-81, respectively.

" Warranties " has the meaning set forth in Section 15.1.2.

" Warranty Issue " has the meaning set forth in Section 15.2.1

" Warranty Period " has the meaning set forth in Section 15.3.

" Westinghouse " means Westinghouse Electric Company, LLC.

" Westinghouse Protected Information " has the meaning set forth in Section 22.3.

" Work " has the meaning set forth in Section 2.1.1.

" Work Package " means an assembly of documentation which describes a specific scope of construction work to be performed.

" Work Schedule " means the schedule of working hours approved by Owners of fifty (50) hours per week per shift, and sixty (60) hours per week per shift for the nine (9) months leading up to cold hydrostatic testing for each Unit.

1.2 Interpretation .

1.2.1 Titles, headings, and subheadings of the various articles and sections of this Agreement are used for convenience only and shall not be deemed to be a part thereof or be taken into consideration in the interpretation or construction of this Agreement.

1.2.2 Words importing the singular only shall also include the plural and vice versa where the context requires. Words in the masculine gender shall be deemed to include the feminine gender and vice versa. Words closely related to a defined term herein shall be interpreted consistent with the defined term (e.g., "Defect" and "Defective," "Notify" and "Notified").

1.2.3 Unless the context otherwise requires, any reference to a document shall mean such document as amended, supplemented or otherwise modified and in effect from time to time.

1.2.4 Unless otherwise stated, any reference to a Party shall include its successors and permitted assigns, and any reference to a Government Authority shall include an entity succeeding to its functions.

1.2.5 Wherever a provision is made in this Agreement for the giving of notice, recommendation, consent or approval by a person, such notice, recommendation, consent or approval shall be in writing, and the word “notify” shall be construed accordingly.

1.2.6 This Agreement and the documentation to be supplied hereunder shall be in the English language.

1.2.7 All monetary amounts contained in this Agreement refer to the currency of the United States unless otherwise specifically provided.

1.2.8 A reference contained herein to this Agreement or another agreement shall mean this Agreement or such other agreement, as they may be amended or supplemented, unless otherwise stated.

1.2.9 Words and abbreviations not otherwise defined in this Agreement which have well-known nuclear industry meanings in the United States are used in this Agreement in accordance with those recognized meanings.

1.2.10 Neither Contractor nor Owners shall assert or claim a presumption disfavoring the other by virtue of the fact that this Agreement was drafted primarily by the other, and this Agreement shall be construed as if drafted jointly by Owners and Contractor. No presumption or burden of proof will arise favoring or disfavoring a Party by virtue of the authorship of any of the provisions of this Agreement.

1.2.11 The words “hereby,” “herein,” “hereunder” or any other word of similar meaning refers to the entire document in which it is contained.

1.2.12 A reference to an Article includes all Sections and Subsections contained in such Article, and a reference to a Section or Subsection includes all subsections of such Section or Subsection.

1.2.13 The words “include,” “includes,” and “including” when used in this Agreement shall be deemed to be followed by the words “without limitation,” unless otherwise specified.

1.2.14 All exhibits referred to in, and attached to, this Agreement are hereby incorporated herein in full by this reference.

1.3 DOE Consent/Approval. The Contractor acknowledges that the Owners (other than Dalton Utilities) (together, the "DOE Borrowers") are required to obtain approval of this Agreement from DOE in order to satisfy certain conditions in the Loan Guaranty Agreements of each DOE Borrower. Owners and the Contractor shall use commercially reasonable efforts to cooperate with the efforts of the DOE Borrowers in obtaining such approval and in facilitating DOE's review of this Agreement, including the consideration of changes to this Agreement that may be requested by DOE. In the event that DOE does not provide such approval, then Owners reserve the right to terminate this Agreement under Section 21.3.

## ARTICLE 2

## CONTRACTOR RESPONSIBILITIES

2.1 Description of Work; Qualifications.

2.1.1 Except as otherwise expressly set forth in this Agreement as being the responsibility of the Owners, Contractor shall perform or provide or cause to be performed or provided: (i) the services, work, obligations and other activities as set forth in Exhibit A; provided that Contractor understands and agrees that the Work must conform to every detail reasonably inferable from Exhibit A as being necessary to produce the intended results as specified in this Agreement applying Prudent Practices, notwithstanding the fact that every detail is not specifically referenced in Exhibit A; (ii) all of Contractor's other obligations set forth in the provisions of this Agreement, in each case in accordance with the requirements of this Agreement (all of the foregoing obligations of the Contractor, including all of such obligations performed or to be performed by Subcontractors, being collectively referred to as the "Work"). Notwithstanding the foregoing, the provision of secondees by Bechtel Power Corporation pursuant to the Amended and Restated Staff Augmentation Agreement shall not be considered part of the Work.

2.1.2 All Contractor and Subcontractor Personnel shall have the necessary experience, qualifications and be properly trained and equipped to perform the Work in accordance with this Agreement. Contractor and Subcontractors shall be properly licensed to perform the Work and authorized and qualified to do business in all governmental jurisdictions in which the Work is to be performed, and will maintain such licenses and qualifications throughout the performance of Work under this Agreement. Upon reasonable advance written request of Owners, Contractor shall furnish to Owners such evidence as Owners may reasonably require relating to the qualifications and ability of Personnel of Contractor and Subcontractor to perform fully in accordance with this Agreement. Owners shall have the right to require the removal from the Site of any Personnel of Contractor or Subcontractor that Owners deem unacceptable.

2.2 Transition of Responsibilities to Contractor. Immediately following the Effective Date, the transitioning of responsibilities for the Work to Contractor and its Subcontractors shall commence and be completed as expeditiously as practicable, in accordance with Exhibit A.

2.3 Monthly Status Reports; Access to Information.

2.3.1 On or before the fifteenth (15th) Day of each month (unless some other frequency is agreed upon by the Parties), Contractor shall submit to Owners, for Owners' review and comment, a written status report covering the prior month (a "Monthly Status Report"). The report shall be prepared in an electronic format reasonably acceptable to Owners and substantially in the form of Exhibit H.

2.3.2 In addition to Monthly Status Reports under Section 2.3.1, promptly upon request by Owners, Contractor shall provide Owners the following information (or reasonable access to such information):

(i) Then-current information of the type that is required to be contained in the form of Monthly Status Report, regardless of whether such information has been or will be later contained within a Monthly Status Report;

(ii) All information that will assist Owners in monitoring the activities comprising the Work and the progress of Work, including all schedule information;

(iii) All information that will assist Owners in monitoring and forecasting costs and expenses in connection with the Work, including Reimbursable Costs and Combined Construction Costs paid and expended.

(iv) All information of a technical nature that pertains to the Work; and

(v) All other information requested by Owners that pertains to Contractor's and its Subcontractors' performance of Work under this Agreement.

2.3.3 Contractor shall, and shall cause its Subcontractors to, participate in the Owners' project information management system for the Facility and the Construction Site, as designed and implemented by the Owners. Contractor and its Subcontractors shall timely provide all information required by this Agreement in a manner required by such project information system.

2.4 Status Meetings. Contractor shall attend and participate in regular meetings with Owners which shall occur monthly (or upon such other interval as the Parties agree) for the purpose of discussing the relevant Monthly Status Report (if applicable) and anticipating and resolving problems. Such meetings may be held by conference call or video conference. Contractor shall prepare and promptly deliver to Owners written minutes of each meeting, to which Owners may respond should they have comments. In addition, Contractor shall attend and participate in weekly (or upon such other interval as the Parties agree) meetings with Owners for the purpose of discussing the status and progress of the Work.

2.5 Embedded Owner Oversight Personnel.

2.5.1 To the extent determined by Owners, Owners may assign Southern Nuclear personnel to specific Contractor functional areas (e.g., project controls, quality control) who will be co-located with Contractor personnel, given full access to Contractor offices at the Construction Site and on-site facilities and IT infrastructure, and who may participate in functional area meetings.

2.5.2 Such Southern Nuclear personnel are provided for Owners oversight and consultation purposes only, are not authorized to give direction to Contractor employees, Subcontractors, or Contractor-Managed Subcontractors, and are not authorized to provide any consents or approvals on behalf of Owners. Contractor will include appropriate provisions in its Subcontracts in order to facilitate similar access by Southern Nuclear personnel consistent with this Section 2.5.

2.6 Performance Standards. All Work performed under this Agreement shall be performed: (i) in a professional, prudent, workmanlike manner by qualified persons using competent, professional knowledge and judgment at the degree of skill and care customary to the nuclear power industry in the United States; (ii) in accordance with applicable Law; (iii) in accordance with the most recently issued Issued for Construction Documents; (iv) in accordance with the requirements of this Agreement; and (v) in accordance with Prudent Practices (collectively, the "Performance Standards"), provided that, notwithstanding anything to the contrary in this Agreement, Contractor shall not be found to have failed to comply with the Licensing Basis if such failure to comply with the Licensing Basis is due to the failure of the most recently Issued for Construction Documents to comply with the Licensing Basis.

2.7 Key Personnel and Labor.

2.7.1 Exhibit I identifies those positions that are designated as "key" management positions (the "Key Personnel"). Individuals so designated as Key Personnel shall be subject to approval by Owners. Contractor shall not remove or replace such individual from such position for at least two (2) years without Owners' prior written consent. If at any time during the performance of the Work any of the Key Personnel should no longer be available to perform services in connection with the Work notwithstanding the commercially reasonable efforts of Contractor, then Contractor will replace such individual with an individual acceptable to Owners. With respect to any replacement of Key Personnel proposed by Contractor, Contractor shall provide the resume of the proposed replacement to Owners for prior approval. Owners will review the resume of such proposed replacement and provide Contractor with comments, approval and/or disapproval within thirty (30) Days from the date of submission of such resume to Owners. If Owner disapproves any individual(s) for a Key Personnel position, then Contractor shall not fill such position with such individual(s). Replacement Key Personnel shall not be removed or replaced from such position until at least the earlier of (i) Mechanical Completion of both Units; or (ii) two (2) years, without Owners' prior written consent.

2.7.2 Exhibit I identifies other lead personnel positions for the performance of the Work ("Other Lead Personnel"). Contractor shall not assign any person to such a position, or remove or replace any person from such a position, without giving notification to Owners of the person to be assigned, removed and/or replaced.

2.7.3 If at any time during the performance of the Work, any of Contractor's or Affiliated Subcontractor's Personnel becomes, for any reason, unacceptable to Owners, then, upon notice from Owners, Contractor will ensure the removal of such unacceptable individual from the Site.

2.8 Independent Contractor.

2.8.1 In its performance under this Agreement, Contractor is and will at all times act as an independent contractor. Subject to the terms and conditions of this Agreement, Contractor will be free to perform the obligations of this Agreement by such methods and in such manner as Contractor may choose, furnishing all labor, tools, Construction Equipment and Construction Materials (in each case to the extent required to be provided in this Agreement), and doing everything else necessary to perform the Work properly and safely, having supervision over and responsibility for the safety and health of Personnel of Contractor, its Subcontractors, and Contractor-Managed Subcontractors while on the Construction Site, and Contractor shall employ all reasonable measures to ensure the safety and health of all such Personnel while on the Construction Site. Unless otherwise specifically directed by Owners, Contractor shall maintain control over and responsibility for its tools, Construction Equipment and Construction Materials. No partnership, joint venture, agency or employment relationship is created by this Agreement or any activity hereunder, and Contractor is not and will not act as an agent or employee of Owners except that Contractor will be permitted to act as Owners' authorized representative with respect to Contractor-Managed Subcontractors in accordance with Section 3.3.1.

2.8.2 Contractor Personnel have no right to participate in any of Owners' employee benefit plans, including the provision of health insurance under the Patient Protection and Affordable Care Act of 2010 ("ACA"), as a result of providing the Work. Contractor shall be solely responsible for (i) payment of all compensation to its employees, (ii) the withholding of federal, state, and local Taxes from such compensation and the payment of all such withheld amounts to the appropriate agencies or authorities, (iii) payment to the appropriate agencies or authorities of state unemployment insurance, federal unemployment insurance, FICA and state disability insurance, and (iv) providing its employees with all necessary and appropriate benefits including any health and welfare coverage required under applicable Law, including, without limitation, the Health Insurance Portability and Accountability Act of 1996, as amended or revised ("HIPAA") or the Patient Protection and Affordable Care Act of 2010 ("ACA") or other applicable Federal and State health care requirements.

2.8.3 Owners have the right to have its Personnel or other authorized representatives inspect the Work pursuant to the applicable provisions of this Agreement, not for the purpose of controlling the methods and manner of the performance of the Work by Contractor under the Agreement, but in order to review whether the Work complies with the requirements of the Agreement and also to review the rate of performance of the Work.

2.9 Inspection.

2.9.1 Inspection Responsibilities. Contractor will perform all inspections appropriate for the performance of the Work as set forth in Exhibit A and the Performance Standards, and such other inspections of the Work as reasonably requested by Owners. Contractor's responsibilities under this Section shall include inspecting the Work in progress at intervals appropriate to the stage of construction as necessary to ensure that such Work is proceeding in accordance with this Agreement and the Baseline Schedule and to protect Owners against defects and deficiencies in such Work.

2.9.2 Owners' Right to be Present. Contractor will keep the Owners fully informed at all times of planned dates, changes to planned dates, proposed test or inspection procedures, and test and inspection results for any testing to or inspections of the Work by or on behalf of Contractor or its Subcontractors or Contractor-Managed Subcontractors. Owners, its designees, and the Independent Engineer shall each have the option of being present at all such scheduled tests and inspections. In the event that the quality of the Work is not in accordance with this Agreement, in addition to any other remedies available under this Agreement, Owners shall be entitled to make recommendations to Contractor for the purpose of remedying such deficiencies. No inspection nor observance of any inspection or testing performed or failed to be performed by Owners, its designees or the Independent Engineer, or any of their respective representatives, shall reduce or waive any of Contractor's obligations under this Agreement or be construed as an approval or acceptance of any Work.

2.10 Testing, Start-Up and Initial Operation. The Work shall include providing craft labor and craft labor supervision (collectively "CSS Personnel") in support of Owners for construction and installation testing by Owners during and after construction, for hot functional testing, for other preoperational testing, and for start-up and performance testing of each Unit and its systems and components (collectively "Commissioning and Startup Support"). Such Commissioning and Startup Support shall be provided in the quantities of CSS Personnel requested in writing by Owners, and such CSS Personnel shall work under the direction of Owners for such periods up through completion of performance testing of both Units as Owners may require. Owners shall indemnify, defend and hold harmless Contractor and Contractor Interests from and against any and all liability, damage, cost, expense and loss arising out of any act or omission of CSS Personnel while acting under and pursuant to the direction of Owners. Costs associated with Commissioning and Startup Support is not part of Combined Construction Costs or the Target Construction Cost, and may be required both before and after Mechanical Completion.

2.11 Clean-Up and Waste Disposal. During the performance of the Work, Contractor shall keep the Construction Site and any other area utilized by Contractor, Subcontractors or Contractor-Managed Subcontractors during construction clean and free from accumulations of waste materials, (other than Hazardous Materials, which are addressed in Section 2.13) rubbish, surplus materials and other debris resulting from the Work. As part of the Work, in accordance with Owners' Site Rules, Contractor will remove such rubbish, surplus materials, waste materials and other debris on a regular basis, or as may otherwise reasonably be required by Owners, and dispose of the same in accordance with this Agreement and applicable Laws.

2.12 Plant Equipment and Materials Storage. Until Final Completion, Contractor shall receive, unload, warehouse or otherwise store appropriately on the Construction Site, in accordance with manufacturers' recommendations, the Plant Equipment and Materials delivered by Owners to Contractor for installation. Contractor shall be responsible for compliance with the receipt, and storage provisions specified in the quality assurance program as described in NQA-1, including NQA-1 Section 13S-1 and other applicable requirements of Owners with respect to storage facilities, for all Plant Equipment and Materials delivered after the Effective Date or on the Construction Site as of the Effective Date. Such appropriate storage shall include implementation of applicable portions of Owners' preventative maintenance program.

2.13 Hazardous Materials.

2.13.1 Material Safety Data Sheets. To the extent required by applicable Law, Contractor shall provide to Owners the "Material Safety Data Sheets" covering Hazardous Materials to be furnished, used, applied or stored by Contractor, its Subcontractors, or Contractor-Managed Subcontractors at the Construction Site in connection with the Work. Contractor shall coordinate with Owners' Authorized Representative to provide a listing of such Hazardous Materials and their quantities at the Construction Site for purposes of chemical inventory reporting pursuant to 40 C.F.R. Part 370 and similar state regulations. Unless authorized in writing by Owners in advance, neither Contractor, its Subcontractors, nor Contractor-Managed Subcontractors shall bring to or use asbestos in the Facility.

2.13.2 Preventative Measures. Contractor shall take measures necessary to prevent the Release by Contractor, its Subcontractors, Contractor-Managed Subcontractors, or by the Personnel or Invitees of any of them, of Hazardous Materials at the Facility or adjacent areas. When the use or storage of explosives or other Hazardous Materials or equipment is necessary for the performance of the Work, Contractor shall exercise the utmost care and shall carry on its activities under the supervision of properly qualified personnel in accordance with applicable Laws. Under no circumstances shall Contractor allow explosives or blasting on the Construction Site without the specific written consent in each instance of Owners. Contractor shall provide not less than three (3) Business Days' notice of each proposed use of explosives or blasting, and each such use shall require a separate specific written acceptance by the Owners. In addition, Contractor shall, no less than one hour prior to each blasting or explosive event, notify the Site Operations Control Center as designated by Owners and confirm that Southern Nuclear has communicated with VEGP Units 1 and 2 prior to commencing blasting or an explosive event. Before Mechanical Completion of Unit 4, Contractor shall remove from the Construction Site and surrounding area in accordance with applicable Laws explosives and other Hazardous Materials supplied or generated by Contractor, Subcontractors or their respective Personnel, unless the same have been permanently incorporated into the Facility; provided that, if any such explosives and other Hazardous Materials are necessary for completion of the Work, Contractor shall be permitted to retain such explosives and other Hazardous Materials at the Construction Site but only if, and to the extent, in compliance with applicable Laws and only until completion of the Work.

2.13.3 Notice Requirements. Contractor shall immediately notify Owners of: (A) any Releases of Hazardous Materials in violation of Law by Contractor, Subcontractors, Contractor-Managed Subcontractors, or by the Personnel or Invitees of any of them, that occur in connection with the performance of the Work; (B) material violations and investigations, actions, Claims, suits, notices of violation, fines, penalties, orders, and other proceedings related to material violations or alleged material violations of Environmental Laws, including, but not limited to, Government Approvals issued thereunder, which are asserted against Contractor, its Subcontractors, Contractor-Managed Subcontractors, or the Personnel or Invitees of any of them, in connection with the Work or their activities on or in connection with the Facility and/or Construction Site; (C) Contractor's discovery of any Hazardous Materials at the Construction Site or adjacent areas; and (D) material developments with respect to Sections 2.13.3(A), 2.13.3(B) or 2.13.3(C). Contractor shall also notify the applicable Government Authorities as required by applicable Law following a Release by Contractor, its Subcontractors, a Contractor-Managed Subcontractor, or the Personnel or Invitees of any of them, of Hazardous Materials in connection with the Work, and shall promptly provide Owners with a copy of such notification(s).

2.13.4 Contractor Releases; Removal Obligations . Prior to Mechanical Completion of a Unit, Contractor will be responsible for the proper handling, collection, containerizing, storage, removing from such Unit and areas adjacent thereto, transportation and for properly disposing of, at treatment, storage and disposal facilities approved by Owners and otherwise in a manner acceptable to Owners and in compliance with this Agreement and applicable Law, all Hazardous Materials generated or Released by Contractor or any Subcontractor or Contractor-Managed Subcontractor, or the Personnel or Invitees of any of them, in the course of performing the Work on such Unit on or after the Effective Date. Except as provided under Section 2.13.5, Contractor shall be the generator of record for such Hazardous Materials and shall obtain a site-specific EPA Identification Number which will be used to identify itself as such on all manifests, hazardous waste reports, and other relevant documents.

2.13.5 Pre-Existing Hazardous Materials . In the event Contractor encounters on the Construction Site material reasonably believed to be Hazardous Material that existed on the Construction Site prior to the Effective Date, then Contractor will immediately suspend performance of Work in the area affected and report the condition to Owners in writing. As between Contractor and Owners, but without affecting any rights or remedies Owners may have against any Third Party, Owners shall be responsible for the remediation of the area affected. Contractor will not thereafter resume performance of the Work in the affected area except with the prior written permission of Owners after the remediation has been completed.

2.14 Turnover Packages . Contractor shall create, maintain, update and compile Turnover Packages during the course of the Work and will deliver to Owners such Turnover Packages prior to, and as a condition of, Mechanical Completion or Final Completion as applicable.

2.15 Safety Program .

2.15.1 Contractor Responsibility . Contractor shall be responsible for the safety of Contractor, its Subcontractors, Contractor-Managed Subcontractors, and the Personnel and Invitees of any of them, Owners' Interests, and the public, in each case to the extent affected by the performance of the Work.

2.15.2 Safety Manual . Contractor shall develop a comprehensive safety program that governs all of Contractor's, Subcontractors' and Contractor-Managed Subcontractors' activities at the Construction Site in connection with its performance of the Work. The safety program shall be reflected in writing in the form of a written project safety manual and provided to Owners no later than thirty (30) Days after the Effective Date (the "Safety Manual"). Contractor's Safety Manual shall, at a minimum, (a) meet the standards and requirements contained in Contractor's generic project safety manual that has been provided to Owners; (b) incorporate and comply with the safety requirements for VEGP Unit 1 and 2 as identified pursuant to that certain Potential Impact Determination on Operating Plans Due to Construction Activities (ND-CS-VNP-005, version 7.0, and any revisions thereto that may be provided by Owners), (c) meet the standard of care for such programs as established by nationally recognized firms which provide goods and services in connection with nuclear construction projects or other large industrial construction projects in the United States, (d) comply with the applicable requirements in the VEGP Units 1 and 2 license, as notified by the Owners, and applicable Laws, and (e) provide other reasonable protection to prevent harm, damage, injury or loss (including ecological harm or nuisance resulting from contamination, noise or other causes arising from the performance of the Work). If Owners reasonably believe that the Safety Manual does not meet the foregoing standards, they shall notify Contractor of such deficiencies in writing and Contractor shall promptly correct such deficiencies in the Safety Manual and implement the corrections into the performance of the Work. Subject to Section 2.13.5, Contractor and its Personnel shall take reasonable precautions for the safety of, and shall provide reasonable protection to prevent damage, injury or loss to Persons and property resulting from the Work, including:

(i) Contractor or any Subcontractor or Contractor-Managed Subcontractor employees and other Persons performing the Work and Persons who may be affected by the performance of the Work;

(ii) any Plant Equipment and Materials to be incorporated into the Facility, whether in storage on or off the Construction Site, under the care, custody or control of Contractor or its Personnel; and

(iii) all materials and equipment and other real and personal property at or adjacent to the Construction Site or in the vicinity thereof, including without limitation VEGP Units 1 and 2 and structures, equipment, facilities, trees, shrubs, lawns, walks, pavements, roadways and utilities.

2.15.3 Safety Measures . Contractor and its Personnel shall erect, maintain or undertake, as required by existing conditions and the performance of this Agreement, reasonable safeguards for the safety and protection of Persons and property who or which may be affected by the Work, including posting danger signs and other warnings against hazards, promulgating safety regulations, and notifying Owners and users of adjacent sites and utilities. Owners shall provide security services as described in NEI 09-01, include providing security guards.

2.15.4 Failure to Take Sufficient Precautions . Whenever, in the reasonable opinion of Owners, Contractor or any Subcontractor or Contractor-Managed Subcontractor have failed to take sufficient precautions for the safety of Contractor, Subcontractors, Contractor-Managed Subcontractors, or the Personnel and Invitees of any of them, Owners' Interests, or the public or the protection of the Construction Site or of structures or property on or adjacent to the Construction Site or on the VEGP Units 1 and 2 site, creating, in the reasonable opinion of Owners, a situation requiring immediate action, then Owners shall be entitled to require that the Work cease immediately, and Owners may cause such sufficient precautions to be taken or provide such protection. The taking of such precautions or protection by Owners or its agents or representatives will not relieve Contractor of any obligations under this Agreement or applicable Laws.

2.15.5 Protection of Units 1 and 2 . No activity of Contractor shall interfere with the operation of VEGP Units 1 and 2. Accordingly, Contractor shall comply with the site restrictions respecting operation of VEGP Units 1 and 2 as identified pursuant to that certain Potential Impact Determination on Operating Plans Due to Construction Activities (ND-CS-VNP-005, version 7.0, and any revisions thereto that may be provided by Owners). For example, offsite power feeds to VEGP Units 1 and 2 shall not be interrupted without the written consent of Owners.

2.15.6 Emergencies . Contractor, Subcontractors, Contractor-Managed Subcontractors and all of their Personnel shall comply with all Site emergency procedures of

Owners, including ensuring capability to respond to a radiological event at VEGP Units 1 and 2. In the event of an emergency endangering or potentially endangering life or property, Contractor shall take such actions as may be reasonable and necessary to prevent, avoid or mitigate injury, damage or loss and shall promptly report each such emergency, and Contractor's responses thereto, to Owners. Contractor agrees to provide to Owners the name, title and phone number of its emergency contact person prior to the commencement of the Work.

2.16 Compliance of Issued For Construction Documents with Laws; Modifications.

2.16.1 As between the Parties, Owners are responsible for the compliance of Issued for Construction Documents with all applicable Laws and Contractor shall not have any obligation to check the Issued for Construction Documents for such compliance. However, in the event Contractor discovers any discrepancy or conflict between any Issued for Construction Documents and applicable Laws, Contractor shall promptly report the same in writing to Owner's Authorized Representative.

2.16.2 In the event that Contractor seeks any modification, change or revision to an Issued for Construction Document, or determines that Work already performed by Contractor does not strictly comply with the Issued for Construction Documents, Contractor is responsible for assessing such modification, change, revision, or Work and determining whether resolution from the Design Authority and/or Owners, as applicable, is required.

2.17 Subcontracting.

2.17.1 Richmond County Constructors LLC. Owners have approved Contractor's use of Richmond County Constructors, LLC ("Richmond") as the principal construction execution Subcontractor for the Facility, subject to the conditions and requirements herein. As of the Effective Date, Contractor represents that Bechtel Power Corporation holds a 75% ownership interest in Richmond, and Williams Plant Services, LLC holds a 25% ownership interest in Richmond. Contractor covenants that:

(i) Bechtel Power Corporation will continue to hold an ownership interest in Richmond of at least 75% through Final Completion;

(ii) no additional Persons shall hold an ownership interest in Richmond or contribute labor or supervision resources to Richmond absent the advance written consent of Owners; and

(iii) no costs asserted as Reimbursable Costs under this Agreement shall include any fee payable to Richmond.

2.17.2 Other Affiliate Subcontractors.

2.17.2.1 Owners additionally approve Bechtel Equipment Operations, Inc. ("BEO") as a Subcontractor for performance of the Work, at BEO's current rental rates at the time of subcontracting to BEO, provided that such rental rates are consistent with prevailing market rates and no markup shall be applied to such rates.

2.17.2.2 Owners additionally approve CAS as a Subcontractor for performance of the Work, at a compensation determined pursuant to Section 7.1.1 and without fee or markup.

2.17.3 Failure to Satisfy Covenants. If the covenants and conditions applicable to any approved Affiliate Subcontractor are not satisfied at any time, such Subcontractor shall no longer be approved to perform Work.

2.17.4 Additional Subcontractors. In the event that Contractor desires to use any additional Subcontractor for Work, Contractor shall notify Owners and, within ten (10) Business Days of such notice, Owners shall notify Contractor if such proposed Subcontractor is not acceptable to Owners. Owners shall have the right to require removal from the Construction Site of any Subcontractor or Subcontractor Personnel deemed unacceptable to Owners. Unless otherwise agreed to by Owners in writing, Contractor shall not use any Subcontractor that has (w) an Experience Modification Ratio (as calculated in accordance with the definition of the National Council on Compensation Insurance, Inc.) of 1.0 or greater within the previous three years; (x) a Recordable Case Incidence Rate (as calculated in accordance with 29 C.F.R. Section 1904.4) of 3.0 or greater within the previous three years; (y) a Days Away From Work Rate (previously known as the Lost Time Incidence Rate, and as calculated in accordance with 29 C.F.R. § 1904.7) of 1.5 or greater within the previous three years; or (z) one or more fatalities during the last three years.

2.17.5 Owners Not Responsible. Notwithstanding any agreement with Subcontractors, Contractor shall be solely responsible for the Work. Unless and until a Subcontract is assigned to the Owners pursuant to this Agreement, Owners shall not be deemed to have any contractual obligation or relationship with any Subcontractor. Contractor shall be as fully responsible for the acts, performance, and omissions of its Subcontractors and of the Personnel either directly or indirectly employed by its Subcontractors as Contractor is for its own acts, performance and omissions. Contractor shall be solely responsible for timely paying each Subcontractor for services, Construction Materials and Construction Equipment, provided in connection with the Work.

2.17.6 Flow-Down Clauses. Contractor shall include in its Subcontracts provisions which impose obligations on Subcontractors that are consistent with the obligations imposed on Contractor in the provisions of this Agreement listed in Exhibit K as those terms are applicable to the Work being performed by the Subcontractor.

2.17.7 Termination for Convenience. Subcontracts must be terminable for convenience, and related termination expenses thereunder must be commercially reasonable in light of the value of the services and other items provided at the time when the termination occurs. In no event shall any termination fees include payment for any types of costs, losses, damages, injuries or claims that would not be payable to Contractor in the event of termination of this Agreement for convenience.

2.17.8 Subcontractor Warranties. Contractor shall cause all warranties and related rights under all Subcontracts to be assignable to Owners without any additional consent or approval from the applicable Subcontractor or other conditions to such assignment. Contractor shall provide Owners a full and complete copy of all such warranties and related rights, and duly executed copies of all contracts with Subcontractors containing such warranties and related rights promptly upon execution thereof. In the event of termination of this Agreement, Contractor shall assign such warranties and related rights to Owners. In addition, as a condition of Mechanical Completion, Contractor shall assign to Owners its rights under such Subcontractor warranties that continue past the end of the Warranty Period, with such assignment to be effective as of the end of the Warranty Period. Contractor shall execute such additional documents as may be reasonably requested by Owner to effect any assignment under this Section 2.17.8. Contractor shall not be relieved of responsibility for any of its obligations, warranties or related rights set forth in this Agreement by reason of any such assignment. Contractor shall not, and Contractor shall take commercially reasonable actions to ensure that Contractor's Subcontractors do not, take any action which could release, void, impair or waive any Subcontractor warranties.

2.17.9 Assignment of Subcontracts. Except with respect to Subcontracts with Affiliates of Contractor, Contractor shall obtain the agreement of all Subcontractors in the terms of each Subcontract that Contractor's rights under the Subcontract may be, at Owners' option, and without requiring the further consent of the relevant Subcontractor, in whole or in part, assigned and delegated by Contractor to Owners. Each such Subcontract shall provide that, upon notification to the Subcontractor (and Contractor) from Owners that (A) this Agreement has been terminated, (B) Contractor's right to proceed with the Work has been terminated pursuant to this Agreement, and (C) Owners will thereafter be assuming Contractor's obligations under such Subcontract related to the Work, such Subcontractor shall continue to perform the portion of its responsibilities under such Subcontract related to the Work for the benefit of Owners and shall recognize Owners as being vested with all the rights and responsibilities of Contractor under such portion of such Subcontract related to the Work. Notwithstanding the foregoing, it is specifically understood and agreed (and each Subcontract shall clarify) that no Subcontractor shall have any right to look to Owners for the performance of any portion of Contractor's obligations under any Subcontract related to the Work, and Owners are not a party to any Subcontract, unless and until Owners have assumed such performance obligations in writing.

2.17.10 Copies of Subcontracts. Contractor shall provide Owners with complete and accurate copies of all Subcontracts, including all amendments, modifications, supplements, and purchase orders thereunder, promptly after the same are in the possession of Contractor.

2.17.11 Transparency of Subcontract Matters. It is the understanding and intent of the Parties that Contractor shall keep Owners informed regarding all significant matters pertaining to its Subcontractors and all Contractor-Managed Subcontractors. Without limiting the generality of the foregoing, after the Effective Date, Contractor shall:

(i) provide the Owners prior notice and reasonable opportunity to attend and participate in all negotiations with Subcontractors and Contractor-Managed Subcontractors, including those relating to amendments and change orders;

(ii) provide Owners the opportunity to attend all regular and special meetings with Subcontractors and Contractor-Managed Subcontractors, with prior notification to Owners of the subject matter of such meetings (to the extent known);

(iii) provide Owners reasonable opportunity to review and provide comments on all Subcontracts, including amendments and change orders thereto, prior to execution of the same;

(iv) keep Owners informed, and provide Owners the opportunity to participate in discussions with Subcontractors and Contractor-Managed Subcontractors regarding actual or potential disputes; and

(v) promptly upon request by Owners, provide Owners information regarding actual and projected costs under the Subcontracts and Contractor-Managed Subcontracts, including for purposes of Owner's budgeting and forecast of Reimbursable Costs and Combined Construction Costs under this Agreement.

2.18 Contractor's Government Approvals. Contractor shall be responsible for obtaining, maintaining and paying for Contractor's Government Approvals as necessary to support the performance of the Work in accordance with the Baseline Schedule. Owners shall provide Contractor reasonable cooperation and assistance in obtaining and maintaining Contractor's Government Approvals.

2.19 ITAACs. Work Packages for Work which has been completed, as delivered by Contractor to Owners, shall include completed documentation of all tests, inspections and analyses associated with any ITAACs applicable to the Work Package. Without assuming any responsibility for correcting any omissions or deficiencies identified, Owners shall be responsible for review of Contractor's Work Packages and for closure of ITAACs. The Parties shall coordinate with each other with respect to those ITAACs associated with the Work. For some or all ITAACs associated with the Work, Owners may specify the methodology to be used in the completion of the tests, inspections and analyses, and Owners shall ensure that such methodology is compliant with Law and adequate for the closure of the ITAAC. Contractor shall perform the Work required by the DOR in accordance with the methodology specified by Owners.

2.20 Support for Government Approvals and Requests. Contractor shall provide support to Owners in connection with Owners' Government Approvals and any requests from Government Authorities, including to the extent appropriate making Personnel available to testify as factual witnesses at formal and informal government proceedings, and providing the documents and information requested by Owners in order to comply with requests of Government Authorities (including to address formal NRC licensing questions and requests of the Georgia PSC), including review and comment to sections prepared by others, and amendments thereto, all on a schedule that supports the Project Schedule in accordance with Owners' reasonable request.

2.21 Control Program.

2.21.1 Contractor shall implement a process for identifying trends in the schedule and costs associated with the Work, in accordance with Exhibit L and Section 2.21.2 ("Contractor Trend Program"). The Contractor Trend Program shall interface with the Owners' overall change control program for the construction of the Facility as described below. All trends identified by the Contractor Trend Program shall be jointly reviewed by the Parties on a weekly basis, and presented to the Owners' change control board for the Facility on a monthly basis.

2.21.2 The Contractor Trend Program shall be implemented to incorporate the following:

(i) Each Monthly Status Report submitted by Contractor shall include: (a) the amount of Contingency that has been used in the performance of the Work and for each trend resolved in accordance with Contractor's Trend Program, both on a cumulative basis and for the previous month; and (b) a forecast of the amount of Contingency needed through Final Completion.

(ii) Upon the expenditure of twenty five percent (25%), fifty percent (50%), seventy five percent (75%), and one hundred percent (100%) of Contingency, Contractor shall notify Owners, and within five (5) Business Days after such notice is provided, the Parties shall attend a meeting for the specific purpose of: (a) reviewing the details of the cumulative expenditure of Contingency; and (b) reviewing the current forecast of Contingency needed through Final Completion.

(iii) Resource curves for labor headcount of Contractor and Richmond Personnel (which curves for field non-manual personnel are set forth in Exhibit M-1, and which curves for craft and indirect craft will be developed during the Baseline Schedule process set forth in Article 9) (which resource curves may be adjusted by mutual agreement of the Parties based on the results of the Subcontract Scope Alignment Process). In the event that the performance of the Work will result in a deviation from any of such resource curves by more than five percent (5%), Contractor shall notify Owners of such deviation. Furthermore, if such deviation will require use of Contingency funds, the deviation will not be permitted without Owners' prior approval. In the event that Contractor proceeds with implementation of the deviation without Owners' prior approval where required, the associated costs of the additional resources related to implementation of the deviation shall be Non-Reimbursable Costs.

(iv) In the event that any trend indicates that the performance of the Work will result in Combined Construction Costs that exceed [***] of the Target Construction Cost, Contractor shall notify Owners of the trend and request Owner's approval of the exceedance before proceeding with implementation of such trend.

(v) The Contractor Trend Program shall incorporate the requirements in Section 3.3 with respect to Contractor-Managed Subcontracts.

2.22 No Waiver of Access Rights. No provision in this Agreement shall be construed as a waiver by Owners of any rights to Contractor's technical, financial or other information that Owners would otherwise have pursuant to legal process in any judicial or administrative proceeding.

## ARTICLE 3

## CONTRACTOR-MANAGED AND OWNER-MANAGED SUBCONTRACTS

3.1 Owner-Managed Subcontracts. "Owner-Managed Subcontracts" refers to subcontracts entered into by Owners (or assigned to and accepted by Owners) with subcontractor entities ("Owner-Managed Subcontractors") to perform construction work and/or services at the Facility, where the responsibilities for administering and managing such subcontractors remain with the Owners. The Owner-Managed Subcontractors and Owner-Managed Subcontracts include those subcontractors and subcontracts designated in Exhibit E as Owner-Managed Subcontractors and Owner-Managed Subcontracts. As between the Parties, Owners are responsible for Owner-Managed Subcontractors' compliance with the Safety Manual. Contractor shall cooperate with Owner-Managed Subcontractors to provide reasonable access to the Construction Site and the opportunity to conduct scheduled work in their respective work areas without interference, and Contractor acknowledges that Owner-Managed Subcontractors will in many cases be conducting such ongoing work in close proximity to Contractor's Work. Owners and Contractor shall coordinate the needs of ongoing work of Owner-Managed Subcontractors with the Work of Contractor as may be required, consistent with their scheduled activities as contained in the Project Schedule.

3.2 Contractor-Managed Subcontract Scope.

3.2.1 The items of scope which are Contractor-Managed Subcontract Scope, and the corresponding Contractor-Managed Subcontracts (as of the Effective Date), are listed in Exhibit E. Unless otherwise agreed by the Parties, the Contractor-Managed Subcontract Scope will be: (i) implemented through Contractor-Managed Subcontracts; (ii) performed directly by Contractor; or (iii) performed via an additional Subcontract (including a Subcontract with Richmond), as determined in the Subcontract Scope Alignment Process in consultation with the Owners.

3.2.2 In the Subcontract Scope Alignment Process, Contractor, in consultation with Owners, will complete its due diligence (including commercial evaluation) related to the Contractor-Managed Subcontract Scope and the related existing subcontractors and subcontracts. The Subcontract Scope Alignment Process is further described in Exhibit E. During the Subcontract Scope Alignment Process, Contractor may, in consultation with Owners:

(i) determine to continue an existing subcontract as a Contractor-Managed Subcontract;

(ii) determine that an existing subcontract needs to be revised, replaced or renegotiated, which as so altered will become a Contractor-Managed Subcontract; and/or

(iii) determine to execute certain Contractor-Managed Subcontract Scope as part of the Work, other than through a Contractor-Managed Subcontract, such as self-performance or performance through Richmond or another Subcontractor.

3.2.3 The Subcontract Scope Alignment Process will be completed in stages on a progressive basis. Completion of each stage will be confirmed by agreement of the Parties in a Change Order, including the appropriate adjustments to the Target Construction Cost, to the Earned Fee, and if needed, to the Target Completion Dates, based upon the results of such stage. Specifically:

(i) The Target Construction Cost shall be increased in accordance with the methodology set forth in Exhibit M, based upon the value of the Contractor-Managed Subcontract Scope that was evaluated in such stage;

(ii) The Earned Fee shall be increased by the amount of [***] of the increase in Target Construction Cost determined in accordance with (i) above;

(iii) If the Contractor-Managed Subcontract Scope evaluated in the Subcontract Scope Alignment Process reveals a material adverse impact on the critical path to achievement of the Baseline Schedule (a "Subcontract Scope Schedule Impact"), then the Baseline Schedule and/or the Target Completion Dates shall be adjusted in accordance with the process described in Section 9.3.

3.2.4 The Subcontract Scope Alignment Process, including all related adjustments to the Target Construction Cost and Earned Fee and identification of Subcontract Scope Schedule Impacts, is to be completed by February 28, 2018. In the event that any such adjustments and identification of Subcontract Scope Schedule Impacts (provided that adjustment to the Baseline Schedule as a result of such impacts shall be made under the process in Section 9.3) are not agreed upon by the Parties by such dates, then, with respect to any Contractor-Managed Subcontract Scope that is a source of disagreement between the Parties regarding an adjustment to the Earned Fee or Target Construction Cost or identification of Subcontract Scope Schedule Impacts, Owners may elect to remove such scope from Contractor-Managed Subcontract Scope by notice in writing to Contractor. If Owners so elect, then: (i) such removed scope shall not be within the Contractor-Managed Subcontract Scope under this Agreement; (ii) Owners shall be responsible for managing and administering such scope either directly or through an Owner-Managed Subcontract(s); (iii) neither the Target Construction Cost nor the Earned Fee shall be adjusted as a result of such removed scope; and (iv) the previously identified Subcontract Scope Schedule Impact with respect to such removed scope shall not be considered under Section 9.3. In the event that the Parties disagree with respect to any proposed adjustments to Target Construction Cost or Earned Fee or identification of a Subcontract Scope Schedule Impact as a result of Contractor-Managed Subcontract Scope that is not so removed by the Owners, then the disagreement may be referred by either Party to the dispute resolution provisions in Article 38 of this Agreement. Any such dispute shall be subject the expedited hearing procedure referenced in the DRB Procedures.

3.3 Contractor Authority and Responsibilities with respect to Contractor-Managed Subcontractors .

3.3.1 Commencing on the Effective Date, Contractor (but not its Subcontractors) shall administer and manage the Contracted-Managed Subcontracts in accordance with the terms and conditions of this Agreement; provided that any schedule or cost impacts identified during the Subcontract Scope Alignment Process will be addressed as part of the Subcontract Scope Alignment Process and in the adjustments to be made pursuant to Section 3.2.3 and Section 9.3. Contractor (but none of its Subcontractors) shall be granted full authority to exercise the rights of, and act as the authorized representative of, the Owners under Contractor-Managed Subcontracts, provided that Contractor shall obtain Owners' written approval prior to taking the following actions under Contractor-Managed Subcontracts:

(i) agreement to an amendment to a Contractor-Managed Subcontract (other than an administrative amendment that does not have any cost or schedule impacts, or violate any of the requirements in subparts (ii) through (vi) below);

(ii) agreement to a change order under a Contractor-Managed Subcontract directing the performance of additional work having a value of over [***] of the baseline value (less applicable contingency) of such Contractor-Managed Subcontract included in the Target Construction Cost (as agreed pursuant to Section 3.2.3) or otherwise creating an obligation of Owners under such Contractor-Managed Subcontract in excess of such [***] threshold amount. Change orders may not be subdivided to avoid this requirement; amounts relating to a single change will be aggregated to determine applicability of this requirement.

(iii) agree upon any modification to or waiver of any provisions of the Contractor-Managed Subcontract relating to warranty, indemnity, limitations of liability or costs to terminate a Contractor-Managed Subcontract;

(iv) agreeing to waive any right that Owners may have under any Contractor-Managed Subcontract, or settling or compromising any dispute or liability under a Contractor-Managed Subcontract;

(v) terminating or suspending any Contractor-Managed Subcontract, other than suspension in an emergency situation; or

(vi) agreeing or committing to do any of the foregoing.

3.3.2 Contractor's management and administration of the Contractor-Managed Subcontracts will be in compliance with Owners' obligations thereunder, including by giving all notices required by each Contractor-Managed Subcontract in order for the Owners to be in compliance with such subcontracts and to protect and preserve the rights of Owners under such subcontract.

3.3.3 Contractor shall be responsible for advising and making a specific action recommendation in writing to Owners, at least 20 Days in advance of: (i) any date when action by Owners is required to be taken under Section 3.3.1 with respect to a Contractor-Managed Subcontract; and (ii) the date that payment is due to be made with respect to a Contractor-Managed Subcontract, including Contractor's recommendation for any withholding of any payments to such subcontractor.

3.3.4 Contractor shall directly perform its obligation to manage Contractor-Managed Subcontracts pursuant to this Agreement. In no event shall Contractor perform such management obligations by or through any of its Subcontractors (including Richmond).

3.3.5 Owners shall retain responsibility for making all payments required under Contractor-Managed Subcontracts; provided, however, that Contractor shall use commercially reasonable efforts to obtain and provide to Owners, all Lien waivers and releases under Contractor-Managed Subcontracts with respect to all work and activities completed under such subcontracts, in a manner consistent with Section 8.11.1(i) and (ii).

## ARTICLE 4

## OWNERS' RESPONSIBILITIES AND RIGHTS

4.1 Owners' Responsibilities. Owners shall perform the responsibilities set forth in this Article and elsewhere in this Agreement at its own expense.

4.1.1 Appointment of Agents. Owners have appointed GPC as their agent in order to execute this Agreement on their behalf and for all purposes under this Agreement pursuant to the Ownership Agreement, with the power and authority to bind Owners to their obligations herein. Except as provided in Sections 8.1 and 19.2, all obligations required under this Agreement to be fulfilled by the Owners will be performed by or at the direction of GPC, as agent for the Owners. Upon notice to Contractor, the Owners may designate another agent to replace GPC to act as their agent under this Agreement. GPC, acting for itself and as agent for the other Owners, has appointed Southern Nuclear as agent for the implementation and administration of this Agreement (provided that upon notice to Contractor, GPC may designate another agent to replace Southern Nuclear as agent for the implementation and administration of this Agreement). Southern Nuclear is the exclusive licensed operator of VEGP Units 1 and 2 and will be the licensed operator ("Licensed Operator") of the Facility having exclusive control over licensed activities at the Facility. GPC represents that: (i) to the extent provided in the Agency Agreements, Southern Nuclear is empowered to exercise Owners' rights under this Agreement; (ii) communications, including notices, decisions and approvals, issued by Southern Nuclear in connection with this Agreement shall be treated as issued by the Owners; and (iii) communications, including notices, sent to Southern Nuclear under this Agreement shall treated as received by the Owners.

4.1.2 Owners' Authorized Representative. By notice to Contractor on or before the Effective Date, Owners shall appoint one or more Persons who shall be entitled to act as an authorized representative of Owner (and shall have the right to appoint a successor or replacement of such authorized representative by notice to Contractor) with whom Contractor may consult at all reasonable times and whose written instructions, requests and decisions shall be binding upon Owners as to all matters pertaining to this Agreement ("Owners' Authorized Representative"). Contractor shall have the right to rely upon a communication from Owners' Authorized Representative as a communication on behalf of all of the Owners, and shall not rely upon or be obliged to comply with any instruction or direction issued by any other representatives of Owners.

Owners' Authorized Representative shall not have any authority to amend this Agreement except in compliance with the provisions of Article 40.4.

4.1.3 Access. Owners shall provide Contractor rights of access to the Construction Site and to other portions of the Site as Contractor may reasonably require for the Work. Owners shall cooperate with Contractor so as to minimize disruption by Owners of Contractor's performance of the Work, and Contractor shall cooperate with Owners so as to avoid disruption by Contractor, Subcontractors, Contractor-Managed Subcontractors or the Personnel of any them of operation of the existing VEGP Units 1 and 2.

4.1.4 Job Site Rules. Subject to the requirements of the operating licenses for VEGP Units 1 and 2, to the extent applicable, Owners shall and shall require Owner-Managed Subcontractors, and their respective representatives and agents, to abide by the Safety Manual.

4.1.5 Owners' Government Approvals. Owners shall be responsible for obtaining, maintaining and paying for Owners' Government Approvals and for the communications with any Government Authorities regarding such Government Approvals. Owners shall provide as much advance notice as practical of the need for the testimony of Contractor's Personnel at proceedings before Government Authorities.

4.1.6 Issued for Construction Documents. As between the Parties, Owners shall be responsible for providing Issued for Construction Documents to Contractor and (as applicable) Contractor-Managed Subcontractors, and for ensuring that such Issued for Construction Documents contain the necessary amount of information to allow Contractor to perform the Work with respect to such Issued for Construction Documents in accordance with this Agreement and to allow the Contractor-Managed Subcontractors to perform their work with respect to such Issued for Construction Documents in accordance with their subcontracts.

4.1.7 Design Authority. By a separate agreement, Owners have contracted with Westinghouse to act as the Design Authority for Units 3 and 4. Pursuant to that agreement, Westinghouse is authorized by Owners to perform the following Owners responsibilities: provide Issued for Construction Documents to Contractor and Contractor-Managed Subcontractors; approve, reject, or make changes, modifications, and revisions to Issued for Construction Documents; and provide interpretations of the design or Issued for Construction Documents. Owners will promptly provide notice to Contractor of the Westinghouse personnel authorized to provide Issued for Construction Documents and communicate design information and shall promptly notify Contractor of any changes in such authorized personnel.

4.1.8 Plant Equipment and Materials. Owners shall be responsible for providing Plant Equipment and Materials to Contractor and to Contractor-Managed Subcontractors and for the quality of such Plant Equipment and Materials, including conformance of such Plant Equipment and Materials with the Issued for Construction Documents.

4.1.9 Construction Equipment. Owners shall be responsible for providing the Construction Equipment located on the Construction Site as of the Effective Date to support the performance of the Work and Contractor-Managed Subcontractor work, and such Construction Equipment shall be provided and maintained by Owners in good working condition. As the Work progresses, the Parties will coordinate a transition such that Contractor, its Subcontractors and/or

Contractor-Managed Subcontractors will provide Construction Equipment for the performance of the Work.

4.2 Owners' Right to Inspect, Stop and Re-Perform Work.

4.2.1 Owners' Right to Inspect. Each Owner shall have the right to have its inspectors, engineers or other designees and representatives of such Owner authorized to do so (the "Designated Persons") or the Independent Engineer inspect the Work at any time and from time to time in order to assure that the Work complies with the requirements of this Agreement, including Contractor's Quality Assurance Program, and to review the rate at which Work is being prosecuted.

(i) The Designated Persons shall be permitted to: (A) follow the progress of the Work and identify defective or nonconforming materials or equipment at source of supply, in process of manufacture, or at point of delivery and (B) monitor actions taken in accordance with Section 4.2.2. The Owners' Authorized Representative shall have the right to stop Work in accordance with Section 4.2.3. Inspection by the Designated Persons shall not be deemed to (A) be supervision by Owners of Contractor and (B) shall not relieve Contractor of any responsibility for performing the Work in accordance with this Agreement. Designated Persons shall not have authority to give direction to Contractor or any Subcontractor or any Contractor-Managed Subcontractor or any of the Personnel of the foregoing. Any acceptance or approval by the Designated Persons shall in no event be deemed to constitute acceptance of same by Owners, but shall be only for the purpose of confirming that the Work appears to comply with this Agreement. Owners may report to Contractor any unsafe or improper conditions or practices observed for action by Contractor in correction or enforcement.

(ii) Without limiting Owners' rights under Article 5, the Designated Persons and the Independent Engineer shall have access to the Work and to applicable parts of Contractor's (or its Subcontractors') work areas on the Construction Site at reasonable times and subject to the reasonable requirements of Contractor or its Subcontractors. Contractor shall not require the Designated Persons or the Independent Engineer to execute documents, releases or waivers purporting to release Contractor from liability for any bodily injury and Contractor shall obtain agreement from its Subcontractors that they will not require such releases from the Designated Persons or Independent Engineer when at the Subcontractors' work areas. Contractor (or its Subcontractors) shall afford the Designated Persons and/or the Independent Engineer such reasonable and safe facilities at Contractor's work areas (or those of its Subcontractors) as are appropriate to conveniently observe and inspect the Work in progress and have such other conveniences as would normally accompany such inspection.

4.2.2 Defective Work. If Owners', the Designated Persons' or the Independent Engineer's inspection reveals any non-compliance or any other defects in any portion of Work, then Contractor shall, promptly upon its receipt of notice from Owners, evaluate such defect or non-compliance in accordance with the Project Corrective Action Program and shall promptly take such actions as are required to correct such defect or non-compliance, as well as its cause, in accordance with the Project Corrective Action Program. Contractor shall not receive any adjustment to the Target Completion Dates or Target Construction Cost or Baseline Schedule for such correction. Contractor shall comply with the requirements of 10 C.F.R. Part 21 and 10 C.F.R. § 50.55(e), as appropriate. A copy of Contractor and Subcontractor notifications relative to this Agreement to the Nuclear Regulatory Commission (NRC) pursuant to 10 C.F.R. Part 21 or § 50.55(e), if any, shall be transmitted to the Owners. Contractor will notify the Owners of any nonconformance reportable to the NRC as well as nonconformances judged not reportable to the NRC but which are considered significant enough to warrant Contractor management action.

4.2.3 Right to Stop Work. Without limiting the right of Owners to suspend performance of the Work under other provisions of this Agreement, if Contractor fails to perform the evaluation required under Section 4.2.2 or fails to promptly take corrective action for any defect or non-compliance in Work as required under Section 4.2.2 or if Contractor fails to identify the root cause of such defect or non-compliance (if root cause is applicable to such non-compliance) within a reasonable period of time consistent with the Project Corrective Action Program, then Owners, by a written order signed by Owners' Authorized Representative, may order Contractor to stop performance of the portion of the Work affected thereby, until the cause of such order has been eliminated; provided, however, that this right of Owners to stop Contractor's performance will not give rise to a duty on the part of Owners to exercise this right for the benefit of Contractor or any other person or entity. In addition, Owners, by written order signed by Owners' Authorized Representative, may order Contractor to stop performance if the activities or past practices of Contractor or its Personnel or Invitees at the Site reasonably appear to Owners to cause or threaten to cause personal injuries or damage to property. In the event of a stop Work order issued by Owners in accordance with this Section 4.2.3, Contractor shall not be entitled to an adjustment to the Target Completion Dates or the Target Construction Cost or the Baseline Schedule. Owners' right to stop Work under this Section 4.2.3 will be without prejudice to any other right or remedy Owners may have hereunder.

## ARTICLE 5

## QUALITY ASSURANCE

5.1 Quality Assurance Programs.

5.1.1 Contractor Quality Assurance Program. Contractor currently has a quality assurance program(s), which will be used in the performance of Work under this Agreement where (a) Contractor is performing the Work itself, (b) a Subcontractor of Contractor is performing Work and Subcontractor does not have an approved quality assurance program, and (c) the Work is performed pursuant to a Contractor-Managed Subcontract and the Contractor-Managed Subcontract includes provisions requiring compliance with Contractor's Quality Assurance Program. Contractor's quality assurance program has been accepted by the NRC ("Contractor's Quality Assurance Program"). Contractor will maintain the Contractor's Quality Assurance Program and any changes thereto shall meet the requirements of 10 C.F.R. Part 50, Appendix B and ASME NQA-1 - 1994. Any changes to Contractor's Quality Assurance Program shall be submitted to and, if necessary, accepted by the NRC consistent with 10 C.F.R. § 50.54(a) and accepted by Owners.

5.1.2 Control of Sub-tier Subcontracting. Contractor shall be responsible for assuring that all its sub-tier Subcontractors that are performing Work are working to Contractor's Quality Assurance Program or to the sub-tier's own quality assurance program that has been approved by Contractor. Contractor shall provide appropriate verification of quality for all sub-tier subcontractors. A sub-tier subcontractor quality assurance program and any changes thereto shall meet the requirements of 10 C.F.R. Part 50, Appendix B and ASME NQA-1 - 1994; provided however that compliance with ASME NQA-1 - 2008, including NQA-1a-2009 Addenda will be considered to be compliant with ASME NQA-1 - 1994.

5.1.3 SNC Quality Assurance Program. For certain Contractor-Managed Subcontracts, subcontractors may perform Work pursuant to the applicable SNC quality assurance program. SNC's quality assurance program has been accepted by the NRC ("SNC Quality Assurance Program"). As delegated through the SNC Quality Assurance Program, Contractor may perform certain Work associated with Quality Assurance for those Contractor-Managed Subcontracts. After completion of the Subcontract Scope Alignment Process, Contractor and Owners will meet and determine which Contractor-Managed Subcontracts shall retain such requirements for compliance with the SNC Quality Assurance Program.

5.2 Transition to Contractor's Quality Assurance Program.

5.2.1 Contractor and Contractor's sub-tier Subcontractors that are working to Contractor's Quality Assurance Program as identified in 5.1.2 will perform Work in accordance with the existing quality assurance programs of Westinghouse Electric Co. LLC and WECTEC Global Project Services Inc., as applicable, until Owners notify Contractor to transition to the Contractor's Quality Assurance Program. The Parties acknowledge that an interface document describing the interface between SNC and Contractor Quality Assurance programs is a prerequisite for the transition to the Contractor's Quality Assurance Program, and, to the extent such interface document is not in force as of the Effective Date, Contractor will provide any support requested by Owners to complete the interface document.

5.2.2 By virtue of a separate services agreement between Owners and Westinghouse Electric Co. LLC and WECTEC Global Project Services Inc., Westinghouse and WECTEC have provided Owners with the documentation regarding their existing ASME QA programs and ASME N-stamp certificates as referenced in NDAQAM, in accordance with ASME requirements. Westinghouse and WECTEC further agreed that they will maintain those programs and certificates. Pursuant to ASME requirements, certain Work performed by Contractor will be governed by such Westinghouse and/or WECTEC ASME QA programs unless and until Owners notify Contractor to transition to the Contractor's ASME Quality Assurance Program.

5.3 Owners Access. Owners shall be given free access to Contractor's facilities and records for inspection and audit of the Contractor's Quality Assurance Program. Provisions will also be made by Contractor, in all Subcontracts, for access by Owners or their representative(s) to Subcontractors' and vendors' facilities and records for similar inspection and audit.

## ARTICLE 6

## SECONDMENT OF EMPLOYEES

The secondment of personnel from Bechtel Power Corporation to Owners and/or Southern Nuclear and from Owners and/or Southern Nuclear to Bechtel Power Corporation will be governed solely by the terms and conditions of the Amended and Restated Staff Augmentation Agreement.

## ARTICLE 7

## COMPENSATION

7.1 Reimbursable Costs .

7.1.1 Except for Non-Reimbursable Costs, costs and expenses incurred by Contractor in performing the Work (including, to the extent provided herein, services that are required in support of the Work) ("Reimbursable Costs") will be payable to Contractor as follows:

(i) Costs actually incurred by Contractor and Contractor's Affiliates Richmond, BEO and CAS, for salaries, wages and standard payroll additives of their non-manual personnel engaged in the performance of the Work, for all the hours of such personnel spent in the performance of the Work in accordance with the Work Schedule as well as any overtime beyond the Work Schedule pursuant to (ii) below; provided that such salaries and wages shall be within the ranges for the applicable grades in accordance with Contractor's then current employment salary and wage policies; provided further that Contractor will provide prior notice to Owners and obtain Owners' prior approval (not to be unreasonably withheld) of any changes to such policies before including requests for compensation of costs based on such changed policies. The rates to be applied for such standard payroll additives as of the Effective Date are set forth in Exhibit N. The rates to be applied for such standard payroll additives will be verified annually by independent audit and subject to adjustment as of the first Day of each calendar year in accordance with any revised legal requirements, insurance rates or changes in Contractor corporate policies.

(ii) Hours worked in excess of 40 hours per week shall be considered overtime hours and such overtime hours shall be compensated in accordance with Contractor's and the applicable Affiliate's overtime policy. For overtime beyond the Work Schedule, Contractor will provide written notification of anticipated additional overtime to Owners in advance, including reasonable details on whether and how any such additional overtime will impact schedule, as well as a proposed breakdown of such anticipated overtime costs; provided further , that Owners shall have the right to instruct Contractor not to incur such additional overtime costs and, in such event, if Owner's denial of or delay in approving of such additional overtime labor impacts achievement of the Baseline Schedule, the Parties will work together in good faith to mitigate such schedule impacts.

(iii) A multiplier for indirect costs in the following percentages: (a) [***] of the non-manual personnel costs described in Section 7.1.1(i) above as they apply to such non-personnel personnel who are assigned to Contractor's home office (e.g., non-manual personnel engaged in required support services); and (b) [***] of the non-manual personnel costs described in Section 7.1.1(i) above as they apply to such non-personnel who are assigned to the Construction Site, in each case of (a) and (b) excluding any premium portion of overtime costs; provided that the foregoing rates of this Section 7.1.1(iii) are intended to cover the indirect costs to Contractor associated with maintaining and establishing offices and field offices, respectively, and such costs shall not be charged as direct costs for the Work and shall not duplicate such direct costs.

(iv) Actual costs of travel, relocation, and personnel assignment to the extent directly related to the performance of the Work, without markup, all of which shall be in accordance with Contractor's then current policies; provided that Contractor will provide prior notice to Owners and obtain Owners' prior approval (not to be unreasonably withheld) of any changes to such policies before including requests for compensation of costs based on such changed policies.

(v) Actual costs of craft labor directly engaged in the performance of the Work, including wages, fringe benefits/taxes, per diems, incentives, pension costs and/or liabilities and other actual craft costs without markup; provided , however , that Contractor will review with Owners any proposals to pay per diems or other incentives to craft labor and will secure Owners' approval for payment of any such amounts in advance of implementing such payments, except that Owners' approval will not be required for the payment of per diems or other incentives to welders so long as the aggregate amount of such per diems or other incentives to welders under this Agreement does not exceed [***] ; provided that, for the avoidance of doubt, all per diems and other incentives for craft labor (except for per diems and other incentives payable to welders) have been excluded from the Target Construction Cost and will be excluded from the calculation of Combined Construction Costs.

(vi) Actual costs relating to craft labor payroll processing and craft labor administration for craft labor directly engaged in the performance of Work.

(vii) Actual costs of Contractor IT support and use of Contractor standard applications determined by utilizing unit rates set forth in Exhibit N.

(viii) Actual costs of construction incurred in the performance of the Work such as costs of Construction Equipment, IT and communications hardware, and Construction Materials.

(ix) Actual amounts paid under Subcontracts entered into by Contractor in order to perform the Work, without markup, subject to the Owner's approval of the applicable Subcontractor as required pursuant to Section 2.17.4.

(x) Actual costs incurred by Contractor in providing support to the Owners related to DOE loan guarantees and providing support to the Owners in connection with dealing with Government Authorities, including as provided in Section 2.20.

(xi) Actual costs of financial securities (including any sales tax bond required by the State of Georgia but excluding the Repayment Letter of Credit as described below), insurances (including DIC insurance relating to the OCIP and other insurances required in the performance of the Work).

(xii) Actual costs of Taxes, licenses and permits directly incurred in the performance of the Work by Contractor or its Subcontractors except for (a) Taxes levied directly on or measured by Contractor's, Subcontractors' and their respective Personnel's income, (b) licenses and permits (other than any sales tax bond required by the State of Georgia) required by Government Authorities in order for Contractor and its Subcontractors to carry on business in the jurisdiction where the Work is performed, and (c) all Taxes covered under any other provision of this Section 7.1.1 as Reimbursable Costs; provided that as between Contractor and Owners, Contractor will be responsible for the payment of all income taxes imposed on it, Contractor's Subcontractors or Contractor Personnel.

(xiii) Other actual costs incurred for the performance of the Work at the Construction Site, without markup.

(xiv) Reimbursable Costs on behalf of Richmond or BEO shall not include any costs that would not be Reimbursable Costs if incurred by Contractor.

Reimbursable Costs previously paid by Owners shall be subject to retroactive adjustment based on the results of audits under Article 36, and any amounts owed by Contractor to Owners pursuant to such audits may be offset by Owners from any amounts otherwise payable to Contractor at any time.

With respect to Excluded Costs that are also Reimbursable Costs, Contractor shall implement a system to track and record such Excluded Costs distinct from other Reimbursable Costs.

7.1.2 Non-Reimbursable Costs means the following:

(i) Salaries and other compensation of Contractor's and Contractor's Affiliates' Personnel not assigned to the Construction Site, except to the extent such Personnel are engaged in performing services in support of the Work, or as expressly approved by Owners.

(ii) Costs and expenses of Contractor's home or branch offices or other offices not at the Construction Site, other than the amounts payable as Reimbursable Costs under Section 7.1.1(iii).

(iii) Any portion of Contractor's or any Person's capital costs or expenses, including interest on capital employed for the Work, subject to Section 8.6 regarding payment of interest in case of late payment.

(iv) Overhead and general costs or expenses of any kind, except as payable as a Reimbursable Cost under Section 7.1.1.

(v) Costs and fees of attorneys, accountants or other consultants, except as expressly authorized by Owners in writing.

(vi) Costs and expenses associated with the Repayment Letter of Credit.

(vii) Other costs or expenses identified as Non-Reimbursable Costs in this Agreement.

7.2 Base Fee and Earned Fee . In addition to Reimbursable Costs, Owners shall pay the Fee to Contractor as and to the extent provided herein. The Fee is comprised of the “Base Fee” and the “Earned Fee,” as follows:

(i) The Base Fee shall be equal to One Hundred Twenty Million Dollars ($120,000,000) and shall be paid in installments as set forth in Section 8.4 and the other provisions of this Agreement pertaining to the payment of Base Fee, subject to Section 21.2.2.

(ii) The Earned Fee shall be equal to the aggregate of (i) One Hundred Twenty Million Dollars ($120,000,000) and (ii) the adjustments in Earned Fee set forth in Change Orders pursuant to the Subcontract Scope Alignment Process in Section 3.2.3. The Earned Fee is comprised of: (a) the “Schedule Earned Fee” for each Unit; and (b) the “Cost Earned Fee.”

(iii) The Schedule Earned Fee for each Unit is equal to twenty-five percent (25%) of the Earned Fee; provided, however, that the Schedule Earned Fee for each Unit shall be subject to increase or reduction as set forth in Section 7.3. Provisional payments of the Schedule Earned Fee shall be made as set forth in Section 8.5, subject to repayment as provided herein.

(iv) The Cost Earned Fee is equal to fifty percent (50%) of the Earned Fee; provided, however, that the Cost Earned Fee shall be subject to increase or reduction as set forth in Section 7.4. Provisional payments of the Cost Earned Fee shall be made as set forth in Section 8.5, subject to repayment as provided herein.

7.3 Modification of Schedule Earned Fee . The Schedule Earned Fee for each Unit shall be subject to either a reduction or increase as follows ***:***

7.3.1 In the event that Mechanical Completion of Unit 3 is not achieved by the date that is ninety (90) Days after the Target Completion Date for such Unit (such date being the “Unit 3 Trigger Date”), then the Schedule Earned Fee for such Unit shall be decreased as follows:

(i) For each of the first thirty (30) Days after the Unit 3 Trigger Date that Unit 3 has not achieved Mechanical Completion, the Schedule Earned Fee for such Unit shall be reduced by [***] per Day;

(ii) After such thirty (30) Day period under Section 7.3.1(i), for each of the next thirty (30) Days that Unit 3 has not achieved Mechanical Completion, the Schedule Earned Fee for such Unit shall be reduced by [***] per Day; and

(iii) After such thirty (30) Day period under Section 7.3.1(ii), for each additional Day that Unit 3 has not achieved Mechanical Completion, the Schedule Earned Fee for such Unit shall be reduced by [***] per Day until the Schedule Earned Fee for such Unit is reduced to Zero Dollars ($0.00).

7.3.2 In the event that Mechanical Completion of Unit 3 is achieved prior to the Target Completion Date for such Unit, then the Schedule Earned Fee for such Unit shall be increased as follows:

(i) For each of the first (30) Days prior to the Target Completion Date for Unit 3 that Unit 3 has achieved Mechanical Completion, the Schedule Earned Fee for such Unit shall be increased by [***] per Day; and

(ii) If Unit 3 has achieved Mechanical Completion more than thirty (30) Days prior to the Target Completion Date for Unit 3, for each additional Day prior to such Target Completion Date that such Unit has achieved Mechanical Completion, the Schedule Earned Fee for such Unit shall be increased by [***] per Day; provided, however, that the total increase of the Schedule Earned Fee for Unit 3 shall be subject to a cap in an amount equal to twenty five percent (25%) of the Earned Fee, as calculated prior to any adjustment under this Section 7.3.2.

7.3.3 In the event that Mechanical Completion of Unit 4 is not achieved by the date that is sixty (60) Days after the Target Completion Date for such Unit (such date being the "Unit 4 Trigger Date"), then the Schedule Earned Fee for such Unit shall be decreased as follows:

(i) For each of the first thirty (30) Days after the Unit 4 Trigger Date that Unit 4 has not achieved Mechanical Completion, the Schedule Earned Fee for such Unit shall be reduced by [***] per Day;

(ii) After such thirty (30) Day period under Section 7.3.3(i), for each of the next forty-five (45) Days that Unit 4 has not achieved Mechanical Completion, the Schedule Earned Fee for such Unit shall be reduced by [***] per Day; and

(iii) After such forty-five (45) Day period under Section 7.3.3(ii), for each additional Day that Unit 4 has not achieved Mechanical Completion, the Schedule Earned Fee for such Unit shall be reduced by [***] per Day until the Schedule Earned Fee for such Unit is reduced to Zero Dollars ($0.00).

7.3.4 In the event that Mechanical Completion of Unit 4 is achieved prior to the Target Completion Date for such Unit, then the Schedule Earned Fee for such Unit shall be increased as follows:

(i) For each of the first thirty (30) Days prior to the Target Completion Date for Unit 4 that such Unit has achieved Mechanical Completion, the Schedule Earned Fee for such Unit shall be increased by [***] per Day;

(ii) If Unit 4 has achieved Mechanical Completion more than thirty (30) Days prior to the Target Completion Date for Unit 4, for each of the next forty (45) Days prior to such Target Completion Date that Unit 4 has achieved Mechanical Completion, the Schedule Earned Fee for such Unit shall be increased by [***] per Day; and

(iii) If Unit 4 has achieved Mechanical Completion more than seventy-five (75) Days prior to the Target Completion Date for Unit 4, for each additional Day prior to such Target Completion Date that such Unit has achieved Mechanical Completion, the Schedule Earned Fee for such Unit shall be increased by [***] per Day; provided, however, that the total increase of the Schedule Earned Fee for Unit 4 shall be subject to a cap in an amount equal to twenty five percent (25%) of the Earned Fee, as calculated prior to any adjustment under this Section 7.3.4.

7.4 <u>Modification of Cost Earned Fee</u> . The Cost Earned Fee shall be subject to either a reduction or increase as follows:

7.4.1 If the Combined Construction Costs are greater than the sum of: (i) the Target Construction Cost; plus (ii) [***] of the Target Construction Cost (“Deadband Amount”) (such sum of the Target Construction Cost and the Deadband Amount being the “Reduction Trigger Amount;” i.e., [***] of the Target Construction Cost), then and in such event the Cost Earned Fee shall be reduced as follows:

(i) For the first [***] of Combined Construction Costs that exceed the Reduction Trigger Amount, the Cost Earned Fee shall be reduced by [***] of such excess/overrun;

(ii) If the Combined Construction Costs exceed the Reduction Trigger Amount by more than [***] , the Cost Earned Fee shall be reduced by [***] of the excess/overrun for the next [***] of such excess/overrun; and

(iii) If the Combined Construction Costs exceed the Reduction Trigger Amount by more than [***] , the Cost Earned Fee shall be reduced by [***] of the excess/overrun for any additional excess/overrun until the Cost Earned Fee is reduced to Zero Dollars ($0.00).

7.4.2 If the Combined Construction Costs are less than the Target Construction Cost reduced by the Deadband Amount (such amount being the "Increase Trigger Amount;" i.e., [***] of the Target Construction Cost), then and in such event the Cost Earned Fee shall be increased as follows:

(i) For the first [***] by which the Combined Construction Costs are less than the Increase Trigger Amount, the Cost Earned Fee shall be increased by [***] of such underrun;

(ii) If the Combined Construction Costs are less than the Increase Trigger Amount by more than [***] , then the Cost Earned Fee shall be increased by [***] of the underrun for the next [***] of such underrun; and

(iii) If the Combined Construction Costs are less than the Increase Trigger Amount by more than [***] , then the Cost Earned Fee shall be increased by [***] of such additional underrun amount; provided, however, that the total of any such increase of the Cost Earned Fee shall be subject to a cap in an amount equal to fifty percent (50%) of the Earned Fee as calculated prior to any adjustment under this Section 7.4.2.

7.5 <u>Adjustments of Reduction and Increase Amounts and Percentages</u> . After the adjustments to the Earned Fee for all stages of the Subcontract Scope Alignment Process have been made pursuant to Section 3.2.3, a one-time adjustment will be made as necessary to the rates of reduction of Schedule Earned Fee stated in Section 7.3.1 and Section 7.3.3 and to the rates of reduction of Cost Earned Fee stated in Section 7.4 so as to preserve the following (provided that corresponding modifications to the rates of increase shall also be made):

(a) for the Schedule Earned Fee for Unit 3, a three (3) month period beyond the Unit 3 Trigger Date over which the Schedule Earned Fee for Unit 3 is reduced to zero at rates that are proportionate to the rates set forth in Section 7.3.1;

(b) for the Schedule Earned Fee for Unit 4, a four (4) month period beyond the Unit 4 Trigger Date over which the Schedule Earned Fee for Unit 4 is reduced to zero at rates that are proportionate to the rates set forth in Section 7.3.3; and

(c) reduction of the Cost Earned Fee to zero when the Combined Construction Costs exceed thirteen percent (13%) of the Target Construction Cost, and such reduction shall be made at rates that are proportionate to the rates set forth in Section 7.4.

7.6 Determination of Final Earned Fee .

7.6.1 The Parties shall cooperate in good faith to seek to agree upon the final amount of Schedule Earned Fee for each Unit within 30 Days of the Mechanical Completion Date of such Unit.

7.6.2 Within 30 Days of Final Completion, Contractor shall submit a proposed final statement of Combined Construction Costs to Owners. Owners shall promptly review such statement and may conduct an audit thereof in accordance with Section 36.4. The Parties agree to utilize their best efforts to agree upon the final amount of Cost Earned Fee within 60 Days following Contractor's submission.

7.6.3 To the extent that the Parties disagree on the amount of the Scheduled Earned Fee and/or the Cost Earned Fee, Contractor shall be entitled to invoice Owners for and Owners shall pay within thirty (30) Days after such invoice any applicable Undisputed Amount pending resulting of the disagreement.

7.7 Sole Liability . NOTWITHSTANDING ANYTHING IN THIS AGREEMENT TO THE CONTRARY, CONTRACTOR'S SOLE LIABILITY FOR SCHEDULE DELAYS AND COST OVERRUNS ARISING OUT OF OR IN CONNECTION WITH THIS AGREEMENT SHALL BE THE REDUCTION OF EACH SCHEDULE EARNED FEE IN ACCORDANCE WITH SECTION 7.3 AND THE REDUCTION OF THE COST EARNED FEE IN ACCORDANCE WITH SECTION 7.4; PROVIDED, HOWEVER, THAT THE FOREGOING SHALL NOT BE CONSTRUED TO LIMIT: (I) ANY OF CONTRACTOR'S OBLIGATIONS UNDER THIS AGREEMENT THAT REQUIRE CONTRACTOR TO OBTAIN OWNERS' APPROVAL FOR CERTAIN COSTS OR THAT REQUIRE CONTRACTOR TO PERFORM AN OBLIGATION IN A SPECIFIC TIME PERIOD; (II) CONTRACTOR'S OBLIGATIONS UNDER SECTION 2.21 AND SECTION 3.3.1; (III) THE PROVISIONS THAT PERTAIN TO REIMBURSABLE COSTS UNDER SECTION 7.1.1; AND (IV) OWNERS' RIGHTS TO TERMINATE THIS AGREEMENT AND THE RIGHTS AND REMEDIES OF OWNERS AS A RESULT OF SUCH TERMINATION AS PROVIDED IN ARTICLE 21.

## ARTICLE 8

## BILLING AND PAYMENTS

8.1 Respective Payment Responsibility . Owners shall be severally, not jointly, liable for the payments due hereunder; provided, however, that GPC shall act on behalf of all Owners for purposes of the receipt of invoices and aggregating the payments received from the Owners prior to making payment in accordance with the provisions of this Agreement. Each individual Owner is responsible for that percentage of the amounts payable to Contractor hereunder that is equivalent to such individual Owner's respective Ownership Interest at the time such payment obligation accrues. In the event that an Owner does not pay in full the amount that is due from such Owner, and another Owner does not make such payment on behalf of such non-paying Owner, GPC shall notify Contractor no later than the due date for the payment of the identity of the Owner(s) that did not pay in full and the amount of such shortfall in payment from such Owner(s).

8.2 Monthly Payment for Estimated Reimbursable Costs .

8.2.1 Prior to the Effective Date, Contractor has provided Owners with a funding request for the estimated Reimbursable Costs for the balance of October 2017 and for the entire calendar month of November 2017 (the "Initial Funding Request"). Owners will make payment of the funds requested in the Initial Funding Request no later than two (2) Days after the Effective Date. Thereafter and beginning with the calendar month following the Effective Date, on or before the tenth (10 th ) Day of each calendar month, Contractor shall provide Owners with a monthly funding request in the format set forth in Exhibit O ("Monthly Funding Request") that sets forth Contractor's good faith estimate of Reimbursable Costs expected to be incurred during the immediately following calendar month (each such period being referred to as a "Monthly Funding Period"). Each Monthly Funding Request shall include a statement certifying that the request includes only Reimbursable Costs that are estimated to be incurred during the next Monthly Funding Period. An example of the process for Monthly Funding Requests, the payment thereof, and the reconciliation and invoicing under Section 8.3, is included in Exhibit O.

8.2.2 Subject to the right of Owners to dispute a Monthly Funding Request to the extent that the funds requested materially differ from the amounts previously indicated by Contractor pursuant to Section 8.2.3 below or do not comply with the terms and conditions of this Agreement, the amount of Reimbursable Costs set forth in each Monthly Funding Request shall be due from Owners within fifteen (15) Days following receipt of the request.

8.2.3 With each Monthly Funding Request issued pursuant to Section 8.2.1, Contractor shall also provide to Owners a good faith estimate of expected Reimbursable Costs for each of the three (3) Monthly Funding Periods following the Monthly Funding Period for which such Monthly Funding Request applies, in the same format as the Monthly Funding Request.

8.2.4 An expected funding profile for the funding of estimated Reimbursable Costs and Fee payments for each year, through the Target Completion Date for each Unit (as of the Effective Date) will be provided by Contractor within thirty (30) Days after the Effective Date. Such expected funding profile will be jointly reviewed by the Parties on an annual basis and adjustments to such funding profile shall be made accordingly based on progress made in performance of the Work and projected Reimbursable Costs and Fee payments.

8.2.5 Contractor will be responsible for making timely recommendations to Owner as to the amounts that should be paid to (or as appropriate withheld from) Contractor-Managed Subcontractors at least twenty (20) Days in advance of payment due dates under the relevant Contractor-Managed Subcontracts, so as to permit Owners to arrange timely payment. Owners will be responsible for making payment to Contractor-Managed Subcontractors by way of direct payment to such subcontractors.

8.3 Monthly Invoices .

8.3.1 With each Monthly Funding Request under Section 8.2.1, commencing with the second Monthly Funding Request, Contractor shall submit the following to Owners:

(i) a statement of Reimbursable Costs incurred for the preceding calendar month (or, in the case of the Initial Funding Request, for the period covered by the Initial Funding Request), including: (a) a reconciliation of such statement of Reimbursable Costs against the funds previously provided by the Owners for such period; and (b) identification of the amount to be paid by the Owners or credited to the Owners based on such reconciliation; and

(ii) an invoice for the monthly installment of the Base Fee to be paid as set forth in Section 8.4 below;

(iii) a separate invoice for:

(a) as applicable, the quarterly amount of each Schedule Earned Fee to be paid as set forth in Section 8.5 below; and

(b) as applicable, the quarterly amount of the Cost Earned Fee to be paid as set forth in Section 8.5 below.

8.3.2 Except for amounts that are disputed by Owners under Section 8.9, the amounts set forth in each invoice under this Section 8.3 shall be due from Owners within fifteen (15) Days following receipt of the invoice.

8.4 Payment of Base Fee . The Base Fee shall be paid to Contractor by Owners each month until the month following achievement of Final Completion in monthly installments. Each monthly installment of the Base Fee shall be equal to a portion of the Base Fee such that, after such installment is paid, Owners shall have paid to Contractor a total portion of Base Fee that is equal to the product of: (i) the Cumulative Final Completion Percentage as of end of the month prior to the invoice date; multiplied by (ii) the total Base Fee.

8.5 Provisional Payments of Schedule Earned Fee and Cost Earned Fee . Owners shall pay to Contractor the Schedule Earned Fee for each Unit and the Cost Earned Fee on a provisional basis, in quarterly installments as provided below. The fourth (4th) calendar quarter of 2017 shall be the first quarter for which such provisional installment shall be paid, which shall be invoiced by Contractor with the Monthly Funding Request issued in January of 2018. Each quarterly installment shall be invoiced by Contractor to Owners with the first Monthly Funding Request in each calendar quarter under Section 8.3.1. Each such quarterly installment shall be determined as follows:

(i) Each quarterly installment of the Schedule Earned Fee for each Unit shall be equal to a portion of the Schedule Earned Fee for such Unit such that, after such installment is paid, Owners shall have paid to Contractor a total portion of Schedule Earned Fee for such Unit that is equal to the product of: (i) the Cumulative Mechanical Completion

Percentage for such Unit as of the end of the previous calendar quarter; multiplied by (ii) the total amount of the Schedule Earned Fee for such Unit (excluding any adjustments to the Schedule Earned Fee under Section 7.3). If the Project Schedule shows that Mechanical Completion of a Unit will not be achieved by the Trigger Date for that Unit, then the amount of the quarterly payment of Schedule Earned Fee for that Unit will be reduced to an amount consistent with the reduced Schedule Earned Fee expected to be earned by Contractor, and future quarterly payments of Schedule Earned Fee for that Unit will similarly be reduced, provided that if a later forecast shows that Mechanical Completion of such Unit will be achieved by the Trigger Date then (i) Contractor will be paid an amount corresponding to the reduced portions of prior quarterly payments of Schedule Earned Fee for that Unit and (ii) future quarterly payments of Schedule Earned Fee for that Unit will be paid without such reduction, unless a future forecast shows that Mechanical Completion of a Unit will not be achieved by the Trigger Date for that Unit.

(ii) Each quarterly installment of the Cost Earned Fee shall be equal to a portion of the Cost Earned Fee such that, after such installment is paid, Owners shall have paid to Contractor a total portion of Cost Earned Fee that is equal to the product of: (i) the Cumulative Final Completion Percentage as of the end of the previous calendar quarter; multiplied by (ii) the total amount of the Cost Earned Fee (excluding any adjustments to the Cost Earned Fee under Section 7.4). If the Project Cost Forecast shows that the Combined Construction Costs will exceed the Reduction Trigger Amount, then the amount of the quarterly payment of Cost Earned Fee will be reduced to an amount consistent with the reduced Cost Earned Fee expected to be earned by Contractor based on the Project Cost Forecast, and future quarterly payments of Cost Earned Fee will similarly be reduced, provided that if a later Project Cost Forecast shows that the Combined Construction Costs will not exceed the Reduction Trigger Amount then (i) Contractor will be paid an amount corresponding to the reduced portions of prior quarterly payments and (ii) future quarterly payments of Cost Earned Fee will be paid without reduction, unless a future forecast shows that the Combined Construction Costs will exceed the Reduction Trigger Amount.

8.6 Late Payment. If for any reason Owners fail to pay Contractor for any sums due and owing by the due date, Contractor will be entitled to interest thereon at the Interest Rate, calculated from the date payment was due. If Owners fail to make payment of an Undisputed Amount on the due date and thereafter such amount continues to be unpaid for fourteen (14) Days after Contractor provides notice to Owners, Contractor shall have the right to suspend performance of the Work until such time as such payment is made. For the avoidance of doubt, if any Owner fails to make payment of its portion of an Undisputed Amount within such fourteen (14) Day period, and another Owner does not make payment of such amount not paid within such fourteen (14) Day period, Contractor shall be entitled to exercise the foregoing rights even if the other Owner(s) make payment of the amounts for which they are responsible.

8.7 Reconciliation of Schedule Earned Fee and Cost Earned Fee.

8.7.1 After the amount of the Schedule Earned Fee for a Unit is finally determined per Section 7.6, to the extent that the aggregate of the installments of the Schedule Earned Fee for such Unit provisionally paid by the Owners under Section 8.5 is more than the amount of the Schedule Earned Fee for such Unit so determined to have been earned by Contractor pursuant to

Section 7.3, then Contractor shall within 30 Days thereafter refund the difference to Owners, with interest at the Interest Rate. Owners may alternatively withhold such difference from any amount payable to Contractor.

8.7.2 After the amount of the Schedule Earned Fee for a Unit is finally determined per Section 7.6, to the extent that the aggregate of the installments of the Schedule Earned Fee for such Unit provisionally paid by the Owners under Section 8.5 is less than the amount of the Schedule Earned Fee for such Unit so determined to have been earned by Contractor pursuant to Section 7.3, then within thirty (30) Days thereafter, Owners shall make payment of the difference to Contractor (including any increased amount of Schedule Earned Fee to which Contractor is entitled under Section 7.3).

8.7.3 After the amount of the Cost Earned Fee is finally determined after Final Completion per Section 7.6, to the extent that the aggregate of the installments of the Cost Earned Fee provisionally paid by the Owners under Section 8.5 is more than the amount of the Cost Earned Fee so determined to have been earned by Contractor pursuant to Section 7.4, then Contractor shall within 30 Days thereafter refund the difference to Owners, with interest determined in accordance with Section 8.6. Owners may alternatively withhold such difference from any amount payable to Contractor.

8.7.4 After the amount of the Cost Earned Fee is finally determined after Final Completion per Section 7.6, to the extent that the aggregate of the installments of the Cost Earned Fee provisionally paid by the Owners under Section 8.5 is less than the amount of the Cost Earned Fee so determined to have been earned by Contractor pursuant to Section 7.4, then within thirty (30) Days thereafter, Owners shall make payment of the difference to Contractor (including any increased amount of Cost Earned Fee to which Contractor is entitled under Section 7.4).

8.7.5 In order to secure the potential repayment under this Section 8.7 of the Schedule Earned Fee for each Unit and/or the Cost Earned Fee, Contractor shall provide an Eligible Letter of Credit to Owners and maintain such Eligible Letter of Credit to secure such potential repayment (the "Repayment Letter of Credit") until the amount of the Cost Earned Fee and the amount of the Schedule Earned Fee for each Unit are finally determined and such repayment (if required) is made. The Repayment Letter of Credit shall initially be in the amount of the aggregate of the Schedule Earned Fee payments and the Cost Earned Fee payments expected to be paid to Contractor in the first twelve (12) months after the Effective Date. The amount of the Repayment Letter of Credit shall thereafter be adjusted annually, such that the adjusted value reflects the aggregate of the amounts of the Earned Fee theretofore paid to Contractor and thereafter expected to be paid to Contractor in the following twelve (12) months.

8.7.6 Owners shall only be permitted to draw upon the Repayment Letter of Credit as follows:

(i) Should Contractor fail to pay the refund amount(s) and applicable interest as determined in accordance with Section 8.7.1 and/or Section 8.7.3, Owners will be entitled to draw on the Repayment Letter of Credit for the amount of the repayment owed by Contractor pursuant to Section 8.7.1 and/or Section 8.7.3.

(ii) If at any time the Repayment Letter of Credit is within sixty (60) Days of expiry, expiration or termination (such sixtieth (60th) Day being the "Renewal Date") and a Repayment Letter of Credit is still required to be maintained under Section 8.7.5, and a substitute or replacement Repayment Letter of Credit that satisfies the requirements of this Agreement as to form, issuer and amount has not been provided by the Day that is fourteen (14) Days after the Renewal Date, Owners shall be entitled to draw upon the full amount of the Repayment Letter of Credit.

8.7.7 Owners may draw upon the Repayment Letter of Credit as provided in Section 8.7.6 regardless of whether a Contractor Event of Default has been declared.

8.8 Final Payment.

8.8.1 Following the later of (i) the conclusion of Commissioning and Startup Support as confirmed by Owners in writing, and (ii) achievement of Final Completion, Contractor shall submit to Owners an invoice for the final payments due under this Agreement (the "Final Payment Invoice"), which shall set forth the remaining amounts due to it pursuant to this Agreement.

8.8.2 When submitting the Final Payment Invoice, Contractor shall: (i) submit a written discharge, in form and substance reasonably satisfactory to both Parties, confirming that the total of such invoice represents full and final settlement of the monies due to Contractor for the applicable Work under this Agreement, except with respect to amounts in dispute that are identified in such discharge, and (ii) include the lien waivers, releases and Contractor's affidavit required by Section 8.11(ii) conditioned on Contractor receiving payment pursuant to such invoice.

8.8.3 Payment of the Undisputed Amount portions of the Final Payment Invoice shall be due from Owners within thirty (30) Days following receipt of the invoice. Contractor's acceptance of payment of such invoice will constitute a waiver of all Claims by Contractor for payment for the applicable Work against Owners (both existing at time of acceptance and arising thereafter), except those previously made in writing and identified by Contactor as unsettled at the time of final payment.

8.9 Payment Disputes.

8.9.1 In the event that Owners dispute any Monthly Funding Request submitted by Contractor under this Agreement, or contend that such Monthly Funding Request is otherwise not in accordance with this Agreement, Owners shall provide notice to Contractor within ten (10) Days after submission to Owners that provides an explanation of the basis for such dispute or contention; provided, however, that the failure of Owners to provide such notice within such time period shall not waive Owners' right to later dispute the amounts set forth in such Monthly Funding Request, and shall in no way limit Owners' rights under this Agreement to later audit any Reimbursable Costs and require adjustments to such Reimbursable Costs or amounts paid based on the results and findings of such audit.

8.9.2 Owners may withhold payment of any disputed amount until the dispute is resolved by agreement of the Parties or pursuant to the dispute resolution provisions contained in

Article 38 of this Agreement; provided, however, that payment shall not waive Owners' right to dispute the payment of Reimbursable Costs or invoiced amounts for any reason in accordance with this Agreement. In the event that Owners dispute only a portion of any Monthly Funding Request or invoice submitted by Contractor under this Agreement, Owners shall make payment of the undisputed portion by the payment due date. Notwithstanding Owners' dispute of a Monthly Funding Request or invoice (or any portion thereof) pursuant to this Section 8.9, Contractor shall continue the performance of the Work pursuant to this Agreement. Within ten (10) Business Days after: (i) an agreement of the Parties resolving a dispute is reached; or (ii) resolution of such dispute under Article 38, Contractor shall refund any amount by which it was overpaid (or Owners may elect to offset or recoup such amount against any amounts owed to Contractor) or Owners shall pay any additional amounts due Contractor, as applicable, to the extent provided for in such agreement or dispute resolution determination. All such payments, offset or recoupment shall include the payment of interest at the Interest Rate. For refunds owed by Contractor to Owners, interest shall accrue from the date Owners made the underlying payment to Contractor to the date Contractor refunds such amount to Owners (or such amount is offset or recouped by Owners). For all other amounts owed, interest shall accrue from the date the payment was originally due until the date the payment is made.

8.10 Supporting Documentation. Contractor shall submit statements and invoices under Section 8.3 in the format set forth in Exhibit P. With each such statement and invoice, Contractor shall provide to Owners copies of all Supporting Documentation, as defined herein, in Excel format and all source documentation in a PDF format, and such additional documentation and materials as Owners may reasonably require to substantiate such statement and invoice. "Supporting Documentation" means, with respect to any statement and invoice, all information in detail sufficient to substantiate and justify the amounts set forth in such statement and invoice, including:

(i) employee time sheets, including employee name, employee ID number, employee title, actual salaries and wages as applicable, appropriate WBS cost code indicating work area and hours worked;

(ii) detail for Contractor-supplied Construction Equipment charges, including equipment type, equipment ID number and applicable cost or rental rate; and

(iii) vendor invoices for material purchases, including material description per item, quantities per item, freight, and sales taxes.

8.11 Conditions of Payments.

8.11.1 Required Submittals. Owners shall not be required to make any payment to Contractor pursuant to this Article 8 if Contractor has not provided the submittals described in this Section:

(i) Interim Lien Waivers and Releases. In order to be valid, each invoice submitted by Contractor must be accompanied by interim lien waivers and releases, in the form and substance as set forth in Exhibit Q, executed by Contractor and Subcontractors having subcontracts exceeding [***], with respect to the Work completed prior to the date of such invoice;

(ii) Final Lien Release; Contractor's Affidavit . In order to be valid, Contractor's invoice for any final payment from Owners under the Agreement must be accompanied by (A) lien releases and waivers executed by Contractor, and all Subcontractors having subcontracts exceeding [***] in the form and substance as set forth in Exhibit Q and (B) Contractor's affidavit in the form and substance as set forth in Exhibit Q executed by Contractor.

8.11.2 Withholding to Protect Owners from Loss . Owners may, without prejudice to any other rights Owners may have, withhold all or any portion of any payment to such extent as may be necessary in Owners' reasonable opinion to protect Owners from loss due to Liens filed by Contractor, any of its Subcontractors, or any of their Personnel against either the Facility, the Site, Construction Site or any other property of Owners other than Liens filed as a result of Owners' breach of their obligations to make payments to Contractor hereunder. When Contractor has remedied the cause for withholding any payment and has furnished evidence of such remedy that is satisfactory to Owners, Owners will make the payment so withheld to Contractor within thirty (30) Days following Owners' receipt of such evidence. If Contractor, after receipt of notice from Owners, fails or refuses to remedy the cause for withholding such payment within the time specified in the notice, then Owners may, without prejudice to any other rights Owners may have, remedy it and charge Contractor for the cost of such remedy including Owners' expenses, such as attorneys' fees and other legal fees and disbursements. Such action by Owners will not be or be considered to be a waiver of any default by Contractor under this Agreement.

8.11.3 Lien Bonds . Owners shall release any payments withheld due to any Lien if Contractor provides to Owners at Contractor's sole expense (i) a lien bond which is (A) issued by a surety company reasonably acceptable to Owners, (B) in form and substance satisfactory to Owners, and (C) in an amount not less than [***] of such Lien Claim or (ii) cash or a letter of credit or other security in form and substance satisfactory to Owners in an amount not less than [***] of such Lien Claim. By posting a lien bond, however, Contractor shall not be relieved of any obligations (including its indemnity obligations) under this Agreement.

8.11.4 Set Off . Owners may set off any sums due and payable by Contractor to Owners under this Agreement against any payments due to Contractor under this Agreement.

8.11.5 Effect of Payment . Owner's payment of an invoice, Monthly Funding Request or any portion thereof shall not constitute an acceptance of any of the Work furnished by Contractor, shall not constitute approval or acceptance of any item or cost in such invoice or Monthly Funding Request, nor shall it shall relieve Contractor of any of its obligations or liabilities under this Agreement. No such payment will constitute a waiver of any Claim which Owners may have against Contractor, including a Claim for defective or non-conforming Work (whether existing at the time of the payment or arising thereafter), regardless of whether the facts of such Claim were known to Owners at the time payment was made.

## ARTICLE 9

## PROJECT SCHEDULE

9.1 Baseline Schedule . Notwithstanding the Unit 3 and Unit 4 Target Completion Dates, the Parties agree to utilize an "early target" as the Baseline Schedule, which as of the Effective Date is premised upon Mechanical Completion for each of Unit 3 and Unit 4 being achieved two (2) months earlier than the respective Target Completion Date for each of Unit 3 and Unit 4 ("Early Completion Targets") (each such two month period is referred to herein as "Schedule Contingency"). For purposes of this Agreement, Schedule Contingency is considered to be for the exclusive use and benefit of Contractor.

9.2 Baseline Schedule Revision .

9.2.1 Contractor acknowledges and agrees that it has reviewed the Baseline Schedule as of the Effective Date, and:

(a) represents and warrants that as of the Effective Date, such Baseline Schedule (including the schedule, sequence and duration of all testing, start-up and commissioning activities) supports the Contractor's performance of Work on a schedule for each Unit to achieve Mechanical Completion by the Early Completion Targets, provided that all of the engineering deliverables and procurement activities (which excludes testing, start-up and commissioning activities) ("Owner E&P Activities") are provided in a timeframe that supports such schedule.

(b) acknowledges and agrees that certain Owner E&P Activities either have not been incorporated into the Baseline Schedule as of the Effective Date or, as currently scheduled, may not support the Contractor's performance of Work on a schedule for each Unit to achieve Mechanical Completion by the Early Completion Targets.

Accordingly, during a period of no more than one hundred eighty (180) Days after the Effective Date, in consultation with Contractor, Owners agree to use commercially reasonable efforts to add and/or revise Owner E&P Activities within the Baseline Schedule in a manner that supports Contractor's performance of the Work on a schedule for each Unit to achieve Mechanical Completion by the Early Completion Targets. Contractor shall cooperate in this process and reasonably accommodate related adjustments in Contractor activities in the Baseline Schedule to support achieving this objective. Owners shall notify Contractor when the above process under this Section 9.2.1 is completed and provide Contractor the proposed revised Baseline Schedule that includes the Owner E&P Activities as added and/or revised under this Section 9.2.1.

9.2.2 For purposes hereof, the "Baseline Schedule Revision Period" shall mean the period of time from the Effective Date until the later of: (i) the Day on which Contractor notifies Owners under Section 9.3.2 that the proposed revised Baseline Schedule provided by Owners under Section 9.2.1 is acceptable, or (ii) if Contractor notifies Owners under Section 9.3.2 that the proposed revised Baseline Schedule is not acceptable, the conclusion of the process set forth in Section 9.3 and establishment of a revised Baseline Schedule pursuant to such provisions.

9.2.3 Without prejudice to Contractor's right to claim an Adjustment Event under Section 9.5 following the Baseline Schedule Revision Period, Contractor agrees that during the Baseline Schedule Revision Period, it shall not assert that any Adjustment Event occurring during the Baseline Schedule Revision Period should adjust the Target Completion Dates, the Target Construction Cost or the Baseline Schedule; provided that during the Baseline Schedule Revision Period, Contractor shall provide notice to Owners of any circumstances or events that Contractor believes may constitute Adjustment Events to be considered under Section 10.4 or 11.4 (except that Contractor shall not be required to provide the information required under Section 10.4.3 or Section 11.4.3 until after the Baseline Schedule Revision Period).

9.3 Requirements and Process for Revised Baseline Schedule Adjustments .

9.3.1 Contractor shall be entitled to an equitable adjustment of the proposed revised Baseline Schedule to the extent that Contractor is able to demonstrate that the aggregate effect of the Owner E&P Activities within the revised Baseline Schedule provided by Owners under Section 9.2.1 and/or any Subcontract Scope Schedule Impacts under Section 3.2.3 and Section 3.2.4:

(a) will have a material adverse impact on Contractor's ability to perform the Work, or any Contractor-Managed Subcontractor's ability to perform its work, on a schedule for a Unit to achieve Mechanical Completion by its Early Completion Target, and

(b) results in a delay to the critical path for a Unit to achieve Mechanical Completion by its Early Completion Target (a "Revised Baseline Schedule Impact").

For the avoidance of doubt, Contractor shall not be entitled to any such adjustment of the proposed revised Baseline Schedule, and no Revised Baseline Schedule Impact shall occur, to the extent that (i) Contractor's representation set forth in Section 9.2.1(a) is found to be incorrect or (ii) Contractor requests changes in writing to the proposed revised Baseline Schedule during the process described in Section 9.2.1.

9.3.2 Within twenty-one (21) Days after Owners provide notice and the proposed revised Baseline Schedule under Section 9.2.1, Contractor shall provide written notice to Owners that either: (i) Contractor accepts such proposed revised Baseline Schedule, in which case such proposed revised Baseline Schedule shall become the Baseline Schedule under this Agreement, or (ii) Contractor does not accept such proposed revised Baseline Schedule, in which event the remainder of this Section 9.3 shall apply, and the revised Baseline Schedule that results from the application of Section 9.3.4 or Section 9.3.5 shall become the Baseline Schedule under this Agreement. If Contractor does not accept the proposed revised Baseline Schedule, then concurrently with such notice, Contractor shall provide Owners a detailed description of: (i) each asserted Revised Baseline Schedule Impact and the resulting asserted adjustment required to the proposed revised Baseline Schedule; (ii) the specific reasons why each asserted Revised Baseline Schedule Impact has or will impact Contractor's ability to perform Work in accordance with a schedule to achieve Mechanical Completion of the Units by the Early Completion Targets, with particular focus on the specific activities on the critical path adversely affected; and (iii) other information reasonably requested by Owners.

9.3.3 As promptly as possible following notice (if any) under Section 9.3.2 that Contractor does not accept the proposed revised Baseline Schedule provided by Owners under Section 9.2.1, Contractor and Owners shall confer with respect to potential measures to mitigate or avoid adverse effects from the asserted Revised Baseline Schedule Impacts, including added cost and delay tradeoffs to minimize the effects on Contractor's ongoing and planned activities. Contractor shall implement reasonable measures for mitigating the effects of any Revised Baseline Schedule Impacts, including (in consultation with Owners) mitigation measures that may involve significant added expenditures in order to avoid or minimize critical path delays. To the extent that Contractor demonstrates that such mitigation measures will result in a material increase to the Combined Construction Costs, Contractor shall be entitled to an equitable increase of the Target Construction Cost pursuant to Section 9.4.

9.3.4 Owners and Contractor agree to cooperate in good faith to resolve any disagreement regarding adjustments to the proposed revised Baseline Schedule as a result of asserted Revised Baseline Schedule Impacts as promptly as practicable, considering the complexity of the events involved. If there has been no resolution of such disagreement within thirty (30) Days after Contractor's notice under Section 9.3.2, then either Party may at any point thereafter initiate the expedited hearing procedure under the DRB Procedures with respect to the disagreement. During the pendency of such disagreement until final resolution, Contractor shall not suspend or slow performance of any Work, or the work of any Contractor-Managed Subcontractor, on account of the disagreement unless directed to do so by Owners pursuant to Section 21.1.

9.3.5 With respect to any asserted Revised Baseline Schedule Impacts that are the subject of an agreed resolution, a DRB determination, or an arbitration award, such resolution, determination or award shall have effect as of the date agreed or rendered. All adjustments to the Baseline Schedule as a result of such resolution shall be set forth in a Change Order signed by the Parties, but noting, to the extent that adjustments are the result of DRB determination(s), that the adjustments remain subject to arbitration as provided in Article 38.

9.3.6 In the event that the Baseline Schedule is revised pursuant to this Section 9.3 as a result of an asserted Revised Baseline Schedule Impact, and as a result the schedule for Mechanical Completion of a Unit under such revised Baseline Schedule is delayed until after the Early Completion Target for such Unit, then the Target Completion Date for such Unit shall be extended for a period equal to such delay, provided that no extension shall be due to the extent that (i) the Project Schedule as of the date of Contractor's notice under Section 9.3.2 projects Mechanical Completion of such Unit being delayed to a date after the Early Completion Target for such Unit and (ii) such delay is attributable to a delay in performance of the Work which is not attributable to an Adjustment Event.

9.4 Adjustment of Target Construction Cost . To the extent that Contractor demonstrates that: (i) the revised Baseline Schedule under this Agreement (as determined pursuant to the first sentence of Section 9.3.2) will result in a material increase to the Combined Construction Costs, (ii) Contractor's accommodation of adjustments in Contractor activities pursuant to Section 9.2.1, or (iii) Contractor's implementation of measures for mitigating the effects of any Applicable Baseline Schedule Impacts under Section 9.3.3 will result in a material increase to the Combined Construction Costs, then Contractor shall be entitled to an equitable increase of the Target Construction Cost. In such event, an Adjustment Event shall be deemed to have occurred and Contractor may proceed under Section 11.4.

9.5 Adjustment Events. Upon the conclusion of the Baseline Schedule Revision Period (including, if applicable, adjustments made per Section 9.3), to the extent that Contractor believes that any Adjustment Events occurred during the Baseline Schedule Revision Period (other than an Adjustment Event under Section 9.4, which shall be dealt with under Section 9.4), Contractor may proceed under Sections 10.3 and 10.4 and/or Sections 11.3 and 11.4, as applicable.

9.6 Project Schedule Management.

9.6.1 Following the Effective Date, the Project Schedule shall be updated at least monthly to reflect progress. The Level 3 versions of the Project Schedule shall be consistent with the Level 2 version at all times. Owners shall be responsible for management and maintenance of the Level 1 and Level 2 versions of the Project Schedule, including data inputs and schedule modifications, and at Owners' election may utilize a separate contractor to provide such services.

9.6.2 Contractor shall be responsible for management and maintenance of the Level 3 version of the Project Schedule with respect to the Work, and any more detailed working-level schedules. Contractor may revise activities, activity durations and sequences in the Level 3 version as such activities pertain to the Work, as needed to reflect its current construction plans and expectations without the consent of Owners, so long as such revisions do not affect the Level 2 Project Schedule. Owners shall have responsibility for the management and maintenance of the Level 3 Project Schedule as it pertains to Owner E&P Activities, and Contractor shall not revise any activity, activity durations or sequences in the Level 3 schedule that are outside of its scope of Work.

9.7 Revisions to Baseline Schedule. The Baseline Schedule shall be modified in order to reflect:

(i) adjustments to the Baseline Schedule as a result of Adjustment Events pursuant to Article 10, and

(ii) adjustments to the Baseline Schedule made pursuant to Section 9.3.

No other revisions to the Baseline Schedule may be made except as mutually agreed by the Parties or made pursuant to Article 38.

Additionally, to the extent that an adjustment of the Baseline Schedule is made by agreement (and not due to the application of Section 9.7(i) or (ii) or as a result of Article 38), no adjustment to either Target Completion Date will be made except as mutually agreed by the Parties. An adjustment to the Baseline Schedule made in accordance with this Section shall not imply or require an adjustment to either Target Completion Date, except to the extent that the standard for adjustment of a Target Completion Date as set forth in Section 9.3 or 10.3 is met.

Baseline Schedule adjustments as determined by the DRB or modified in arbitration per

Article 38, shall be promptly reflected in the Baseline Schedule following such agreement or determination.

9.8 Schedule Recovery Plans .

9.8.1 If, during the performance of the Work, Contractor is delayed such that Mechanical Completion of a Unit is projected to be achieved after the Target Completion Date for such Unit (as indicated in the current Project Schedule) Owners may require Contractor to prepare a proposed plan that feasibly explains how Contractor will improve schedule progress to achieve Mechanical Completion for such Unit by its Target Completion Date (each such plan a "Recovery Plan"), and Contractor will participate in such meetings as Owners may reasonably require in connection with the preparation and implementation of such Recovery Plan.

9.8.2 Contractor will submit its proposed Recovery Plan to Owners within a reasonable period of time (considering the complexity of the issues involved) after Owners provide notice to Contractor's Authorized Representative, but not more than thirty (30) Days after notification by Owners of such request for a Recovery Plan; provided that in the event Contractor does not submit a Recovery Plan within thirty (30) Days of Owners' request, Owners shall be entitled to withhold future provisional payments of the portion of the Schedule Earned Fee with respect to the Unit in question until a Recovery Plan is approved (approval not to be unreasonably withheld). Upon receipt of such proposed Recovery Plan, Owners will review and comment upon the same within ten (10) Days. Contractor will accept and incorporate Owners' reasonable comments and resubmit, within ten (10) Days of receiving such comments, the proposed Recovery Plan to Owners. Contractor will implement the approved Recovery Plan, and will use commercially reasonable efforts to adhere to such Recovery Plan in order to achieve Mechanical Completion of such Unit by the Target Completion Date for such Unit. Owners' approval of the Recovery Plan will not relieve Contractor of any of its obligations under this Agreement. Additional costs associated with implementing an approved Recovery Plan shall be Reimbursable Costs, and any schedule revisions set forth in an approved Recovery Plan shall be promptly incorporated into the Project Schedule.

9.8.3 Owners may request that Contractor accelerate any aspect of the Work. Contractor shall use commercially reasonable efforts to meet Owners' request.

## ARTICLE 10

## TARGET COMPLETION DATES AND GROUNDS FOR ADJUSTMENTS

10.1 Target Completion Dates. Subject to adjustment as provided in this Article, the Target Completion Date for Unit 3 shall be May 31, 2020, and the Target Completion Date for Unit 4 shall be May 31, 2021.

10.2 Adjustments to Target Completion Dates. The Target Completion Dates shall be subject to adjustment only as follows:

(i) adjustments made in accordance with Section 9.3; and

(ii) adjustments made for Adjustment Events in accordance with the procedure and applicable standards set forth in Section 10.4.

10.3 Adjustment Events. In the event of occurrence of an Adjustment Event, that Contractor demonstrates: (i) has a material adverse impact on Contractor's ability to perform the Work or on a Contractor-Managed Subcontractor's ability to perform its work in accordance with the Project Schedule in effect as of the Adjustment Event; and (ii) causes a delay to the critical path in the Project Schedule for achievement of either or both Unit Mechanical Completion Dates, Contractor shall be entitled to equitable adjustment of the Target Completion Dates and the Baseline Schedule to the extent of such critical path impact. Provided, however, to the extent a delay due to an Adjustment Event runs concurrently with a delay not due to an Adjustment Event, Contractor shall not be entitled to such an adjustment or time-related cost adjustment for the period of such concurrent delay. In addition, for the avoidance of doubt, in the event of a concurrent delay resulting from two or more Adjustment Events, Contractor is only entitled to such an adjustment to the extent of the impact to the critical path, without duplication.

10.4 Requirements and Process for Target Completion Date Adjustments.

10.4.1 Notice. Contractor shall provide written notice to Owners of the occurrence of an event that Contractor considers an Adjustment Event as promptly following such event as practicable, but in any case within twenty-one (21) Days of when Contractor became aware of such event and that it was likely to have a material impact.

10.4.2 Consultation and Mitigation. As promptly as possible following any such notice, Contractor and Owners shall confer with respect to potential measures to mitigate or avoid adverse effects from the asserted Adjustment Event, including added cost and delay tradeoffs to minimize the effects on Contractor's ongoing and planned activities. Contractor is responsible for implementing all reasonable measures for mitigating the effects of any Adjustment Event, including (in consultation with Owners) mitigation measures that may involve significant added expenditures in order to avoid or minimize critical path delays.

10.4.3 Request Submission. As promptly as practicable following such notice, but in any case within thirty (30) days after such notice unless otherwise agreed by Owners, Contractor shall provide Owners its request for adjustment with respect to any asserted Adjustment Event, to include: (i) a detailed description of the asserted Adjustment Event, (ii) the specific reasons why the asserted Adjustment Event has or will impact Contractor's performance, with particular focus on the specific activities on the critical path adversely affected; (iii) a schedule analysis based on the Project Schedule identifying the specific critical path activity impact(s) asserted and their extent; (iv) the asserted adjustment required to the Baseline Schedule and the Target Completion Date(s); (v) an explanation of Contractor's mitigation efforts and strategy to minimize the impact of the asserted Adjustment Event; and (vi) relevant documentation supporting Contractor's factual assertions.

10.4.4 Review by Owners. Owners shall promptly review Contractor's submission in accordance with Section 10.4.3, and may request additional information or conduct its own independent review or analysis of the asserted Adjustment Event and its impact. Any adjustment to which the Contractor may be entitled for an Adjustment Event shall not include a time extension to the extent Contractor failed to implement reasonable mitigation measures to mitigate the effects of the Adjustment Event.

10.4.5 Prompt Resolution. Owners and Contractor agree to cooperate in good faith to reach agreed resolution of any adjustment(s) for asserted Adjustment Events as promptly as practicable, considering the complexity of the events involved. If there has been no resolution of such adjustments 60 days after submission of the information required by Section 10.4.3, Contractor may at any point thereafter initiate the expedited hearing procedure under the DRB Procedure with respect to the asserted adjustment. During the pendency of any asserted adjustment until final resolution, Contractor shall not suspend or slow performance of any Work on account of the dispute related to the asserted Adjustment Event unless directed to do so by Owners pursuant to Section 21.1.

10.4.6 Effective Date of Adjustments. With respect to any asserted Adjustment Event that is the subject of an agreed resolution, a DRB determination (pursuant to either the expedited or regular hearing procedures under the DRB Procedure), or an arbitration award, which affects the Target Completion Date(s), or the Baseline Schedule, such resolution, determination or award shall have effect as of the date agreed or rendered. All adjustments shall be set forth in a Change Order signed by the Parties, but noting, to the extent that adjustments are the result of DRB determination(s), that the adjustments remain subject to arbitration as provided in Article 38.

## ARTICLE 11

## TARGET CONSTRUCTION COST AND ADJUSTMENTS

11.1 Target Construction Cost. Exhibit M sets forth: (i) the amounts that comprise each category of Target Construction Cost; and (ii) Excluded Costs.

11.2 Adjustments to Target Construction Cost. The Target Construction Cost shall be subject to adjustment only as follows:

(i) adjustments made in accordance with the Subcontract Scope Alignment Process set forth in Section 3.2.3;

(ii) adjustments made for Adjustment Events in accordance with the procedure and applicable standards set forth in Section 11.4 (including as a result of the application of Section 9.4); and

(iii) the Target Construction Cost shall be decreased or increased (as applicable) to reflect the addition or reduction of personnel after the Effective Date that are seconded to Contractor under the Amended and Restated Staff Augmentation Agreement, in an amount determined consistent with the basis used to determine the costs included in the initial Target Construction Cost set forth in Exhibit M. In the case of Fluor personnel who are seconded to Southern Nuclear under a separate agreement and in turn seconded to Contractor pursuant to the Amended and Restated Staff Augmentation Agreement, the Target Construction Cost will only be adjusted to account for Fluor personnel who are seconded to Contractor beyond November 7, 2017.

11.3 Adjustment Events. In the event of occurrence of an Adjustment Event that Contractor demonstrates will result in a material increase to the Combined Construction Costs, Contractor shall be entitled to an equitable increase of the Target Construction Cost to that extent. In the event of occurrence of an Adjustment Event that Owners demonstrate will result in a material decrease in the Combined Construction Costs, Owners shall be entitled to an equitable decrease of the Target Construction Cost to that extent; provided that Adjustment Events that may result in a decrease in the Combined Construction Costs are limited to those set forth in subparts (i), (ix) and (x) of the definition of Adjustment Event in Article 1. For the purposes of this Agreement, Contingency is considered to be for the exclusive use and benefit of Contractor.

11.4 Requirements and Process for Target Construction Cost Adjustments.

11.4.1 Notice. Contractor shall provide written notice to Owners of the occurrence of an event that Contractor considers an Adjustment Event as promptly following such event as practicable, but in any case within twenty-one (21) Days of when Contractor became aware of such event and that it was likely to have a material impact. Owners shall provide written notice to Contractor of the occurrence of an event that Owners consider an Adjustment Event as promptly following such event as practicable, but in any case within twenty-one (21) Days of when Owner became aware of such event and that it was likely to have a material impact.

11.4.2 Consultation and Mitigation. As promptly as possible following any such notice, Contractor and Owners shall confer with respect to potential measures to mitigate or avoid adverse effects from the asserted Adjustment Event, including added cost and delay tradeoffs to minimize the effects on Contractor's ongoing and planned activities. Contractor is responsible for implementing all reasonable measures for mitigating the adverse effects of any Adjustment Event.

11.4.3 Request Submission. As promptly as practicable following such notice, but in any case within thirty (30) days after such notice unless otherwise agreed by the other Party, Contractor shall provide Owners, or Owners shall provide Contractor, its request for adjustment with respect to any asserted Adjustment Event, to include: (i) a detailed description of the asserted Adjustment Event, (ii) the specific reasons why the asserted Adjustment Event has or will impact Contractor's performance, with particular focus on the cost elements affected; (iii) the projected impact on Combined Construction Costs associated with the Adjustment Event, with specific cost breakdown; (iv) the proposed adjustment in the Target Construction Cost, after incorporating any related savings; (v) an explanation of Contractor's mitigation efforts and strategy to minimize the impact of the asserted Adjustment Event; and (vi) relevant documentation supporting Contractor's or Owners' factual assertions. The other Party shall promptly review such submission made in accordance with Section 11.4.3, and may request additional information or conduct its own independent review or analysis of the asserted Adjustment Event and its impact. Any adjustment to which the Contractor may be entitled for an Adjustment Event shall not include additional costs to the extent Contractor failed to implement reasonable mitigation measures to mitigate the adverse effects of the Adjustment Event.

11.4.4 Prompt Resolution. Owners and Contractor agree to cooperate in good faith to reach agreed resolution of any adjustment(s) for asserted Adjustment Events as promptly as practicable, considering the complexity of the events involved. If there has been no resolution of such adjustments 60 days after submission of the information required by Section 10.4.3, the Party claiming an adjustment may at any point thereafter initiate the expedited hearing procedure under the DRB Procedure with respect to the asserted adjustment. During the pendency of any asserted adjustment until final resolution, Contractor shall not suspend or slow performance of any Work on account of the dispute related to the asserted Adjustment Event unless directed to do so by Owners pursuant to Section 21.1.

11.4.5 Effective Date of Adjustments. With respect to any asserted Adjustment Event that is the subject of an agreed resolution, a DRB determination (pursuant to either the expedited or regular hearing process), or an arbitration award, which affects the Target Construction Cost such resolution, determination or award shall have effect as of the date agreed or rendered. All adjustments shall be set forth in a Change Order signed by the Parties, but noting, to the extent that adjustments are the result of DRB determination(s), that the adjustments remain subject to arbitration as provided in Article 38.

## ARTICLE 12

## OWNER DIRECTED CHANGES

12.1 Right to Direct Changes. Subject to the limitation in Section 12.2, Owners may at any time direct an addition to or deletion from or other change in the general scope of Work to be performed by Contractor hereunder (an "Owner Directed Change"), provided that any change to the DOR is subject to the written agreement of both Parties. Additional costs associated with the Work as changed shall be Reimbursable Costs to the extent consistent with Section 7.1.1. Contractor shall proceed with the Work as changed without interruption or slowdown, except that where Contractor notifies Owners within five (5) Business Days of its receipt of the change direction that such change would adversely impact safety or materially impair Contractor's compliance with applicable Laws, Contractor shall not be obliged to proceed with the change. In no event shall Contractor be obligated to proceed with any change that requires Contractor to violate an obligation imposed by Law, provided that any disputes regarding the applicability and requirements of Law in such situations shall be resolved by the expedited hearing procedure in the DRB Procedures.

12.1.1 NRC Change in Law. If either Party becomes aware of an NRC Change in Law impacting the Work performed under this Agreement, it will give notice to the other Party within thirty (30) Days of becoming aware. Owners may decide to take any of the following actions in order to address such NRC Change in Law: (a) Owners may issue an Owner Directed Change directing changes to the impacted Work, (b) Owners may issue a request for proposal to Contractor with respect to the impacted Work pursuant to Section 12.5 which Owners may accept at their sole discretion, or (c) Owners may notify Contractor that the work required by the NRC Change in Law will not be included in the scope of the Work; provided that a notification under (c) will be treated as an Owner Directed Change if it results in an addition to or deletion from or other change in the general scope of Work to be performed by Contractor per Section 12.1.

12.1.2 Compliance with Law. In the event that there is a disagreement between Owners and Contractor regarding whether Work that has been, is in the process of being, or will be performed is compliant with applicable Law ("Applicable Law Compliant"), Owners may issue a notice to Contractor under this Section (a "Section 12.1.2 Notice") to communicate a determination that, in Owners' opinion, the Work is not or will not be Applicable Law Compliant and to notify Contractor to proceed with such Work (or re-Work) in accordance with Owners' determination so as to ensure, in Owners' opinion, that such Work will be Applicable Law Compliant. Contractor shall continue with such Work (or re-Work) in accordance with the Section 12.1.2 Notice, but without prejudice to any contention by Contractor that the Section 12.1.2 Notice constitutes an Owner-Directed Change. In no event shall Contractor be entitled to discontinue, suspend or interrupt Work due to a Section 12.1.2 Notice. Contractor shall be entitled to make a claim pursuant to Article 38 that its Work absent Owners' determination was or would have been Applicable Law Compliant and, if it is determined in accordance with Article 38 or otherwise agreed that the Work in question was or would have been Applicable Law Compliant, Owners' Section 12.1.2 Notice pursuant to this Section 12.1.2 shall be treated as an Owner-Directed Change. To the extent that the issue as to whether or not Contractor's Work was or would have been Applicable Law Compliant is incapable of determination under Article 38, Owners' Section 12.1.2 Notice shall not be treated as an Owner-Directed Change.

12.2 Limitation Respecting Core Scope. An Owner Directed Change that deletes an item of Work that is within the Core Scope may be made only in circumstances where: (a) Contractor has materially failed to perform such item of Work in accordance with the requirements of this Agreement, and has failed to correct such failure within the timeframe provided in Section 21.2.1(i) following notice of such failure; or (b) there is no longer a need for such item of Work (e.g., in the case of a decision by the Owners to discontinue the completion of a Unit). The limitation of this Section does not affect Owner Directed Changes that delete Non-Core Scope, which are not limited.

12.3 Adjustment to Target Construction Cost and/or Target Completion Date(s). Should Contractor or Owners consider that any Owner Directed Change will require an adjustment to the Target Construction Costs and/or the Target Completion Date(s), such Party shall give the other Party written notice to that effect as provided in Section 10.4.1 or Section 11.4.1, and shall proceed in accordance with Sections 10.4 and 11.4, as applicable, to determine such adjustment.

12.4 Fee Adjustment .

12.4.1 In the event of an Owner Directed Change that either reduces or increases the Work, no adjustment will be made to the Fee except as follows:

(a) where the value of the increase in Work (calculated on the basis of the value of such increased scope including escalation and contingency) exceeds a threshold of [***] , the Fee will be increased in an amount equal to [***] of such scope increase value. Changes will be evaluated against this threshold individually, and unrelated changes will not be considered as a group in order to affect meeting this threshold; and

(b) where the value of the reduction in Work (calculated on the basis of the value of such reduced scope remaining to be performed, using the estimate which formed the basis for the Target Construction Cost as of the Effective Date) exceeds a threshold of [***] , the Fee will be reduced in an amount equal to [***] of such scope reduction value. Changes will be evaluated against this threshold individually, and unrelated changes will not be considered as a group in order to affect meeting this threshold.

12.4.2 Where an adjustment to the Fee is made pursuant to Section 12.4.1, such adjustment value shall be allocated to the Base Fee and Earned Fee in the same proportion as the split between Base Fee and Earned Fee determined after the adjustments to the Earned Fee for all stages of the Subcontract Scope Alignment Process have been made pursuant to Section 3.2.3.

12.5 Proposed Changes . At any time, Owner may request that Contractor provide a proposal, to include a detailed breakdown of estimated added cost or savings and any impact on the Baseline Schedule, Target Completion Date(s) or Target Construction Costs, with respect to a contemplated Owner Directed Change. Such proposals shall be provided within 14 days following Owners request or such other period as the Parties may agree. Such a proposal request does not constitute an Owner Directed Change and does not authorize Contractor to commence performance of the contemplated change, until such time as separately directed by the Owners in writing in accordance with Section 12.1. Owners shall pay to Contractor the Reimbursable Costs associated with compliance with this Section 12.5.

12.6 Change Orders Final . Each Owner Directed Change shall be set forth in a Change Order signed by the Parties that memorializes the nature of the change and any adjustments to the Target Completion Date(s) and/or Target Construction Cost agreed, or that confirm no such adjustments are required. Executed Change Orders are the final agreement of the Parties on the subject and may not be reopened for any reason, unless the Change Order states that it is based on a determination of the DRB that is subject to later arbitration per Article 38.

12.7 NRC Submittals Requested by Contractor . In the event that Contractor's failure to comply with the Performance Standards or any other provision of this Agreement causes the Work or planned Work to be noncompliant, or where Contractor desires to modify the Work for its own convenience, Owners and Contractor may agree that Owners should process an NRC submittal to address the noncompliance or allow for Contractor's desired modification. In the event that Owners and Contractor agree that Owners will process such a submittal, Owners shall be entitled to a set-off against amounts due pursuant to this Agreement for Owners' costs associated with such submittal. Owners shall have no liability for, and there shall be no Owner-directed Change, Change in Law, or NRC Change in Law, to the extent arising from delay in or an unfavorable result from any such submittal agreed upon by the Parties. Nothing in this Section 12.7 shall obligate Owners to process an NRC submittal.

## ARTICLE 13

## FORCE MAJEURE EVENTS

13.1 Force Majeure Event . As used in this Agreement, a "Force Majeure Event" means any event or circumstance to the extent that it: (a) prevents or materially delays the affected Party (the "Affected Party") in performing its obligations under this Agreement; and (b) is beyond the reasonable control of and not the result of the fault or negligence of the Affected Party or such Affected Party's Personnel; and (c) could not have been prevented by the Affected Party's or its Personnel's exercise of reasonable diligence. To the extent that the preceding conditions are satisfied, Force Majeure Events include the following events or circumstances:

(i) war, civil insurrection, riots, sabotage or acts of terrorism;

(ii) acts of God, including flash floods, hurricanes, tornadoes, typhoons, lightning strikes, earthquakes and the like;

(iii) epidemics, quarantines, embargoes or blockades;

(iv) delay by a Government Authority that amounts to a refusal to act or delay that is substantially more significant than the period that would be reasonably expected for the applicable Governmental Authority action, except to the extent attributable to any act or omission of Contractor, Subcontractor or any Contractor-Managed Subcontractor; and

(v) delay experienced by a Subcontractor or Contractor-Managed Subcontractor to the extent such delay is caused by an event that would constitute a Force Majeure Event if such event were experienced directly by Contractor.

Notwithstanding anything in this Section 13.1 to the contrary, in no instance will the following constitute a Force Majeure Event: (a) equipment failure, except when such failure is caused by a separate Force Majeure Event; (b) an act or omission of a Subcontractor or Contractor-Managed Subcontractor, except to the extent such act or omission is caused by an event that would constitute an Force Majeure Event if such event were experienced directly by Contractor; (c) changes in market conditions, including price fluctuations with respect to materials, labor, supplies or components of equipment; (d) economic hardship; (e) labor strikes or other labor actions that are directed at Contractor, a Subcontractor or Contractor-Managed Subcontractor; (f) normal climatic conditions (based upon a fifteen (15) year average) at the Construction Site; (g) changes in Laws; (h) delay by a Government Authority that does not amount to a refusal to act or is not substantially more significant than the period that would be reasonably expected for the applicable Governmental Authority action.

13.2 Burden of Proof. The burden of proof as to whether an Force Majeure Event has occurred shall be upon the Party claiming an Force Majeure Event.

13.3 Excused Performance. To the extent that the Affected Party is rendered wholly or partly unable to perform its obligations under this Agreement because of a Force Majeure Event:

(i) the Affected Party's performance of such obligations (except for its payment obligations) shall be excused;

(ii) the Affected Party shall give written notice to the other Party describing the particulars of the occurrence as soon as reasonably practicable under the circumstances after the Affected Party becomes aware of the Force Majeure Event;

(iii) the suspension of performance resulting from such Force Majeure Event shall be of no greater scope and of no longer duration than is reasonably required by the Force Majeure Event;

(iv) no obligations of either Party which arose before the occurrence causing the suspension of performance are excused as a result of the occurrence, except to the extent the occurrence prevents their completion;

(v) the Affected Party must continue to perform its obligations under this Agreement to the extent commercially reasonable, and the Affected Party must use commercially reasonable efforts to overcome, cure, remove, otherwise correct, minimize and contain costs and expenses and mitigate and remedy the damages, delays and effects of the Force Majeure Event and its inability to perform its obligations under this Agreement as a result thereof; and

(vi) when the Affected Party is able to resume performance of its obligations hereunder, that Party shall give the other Party written notice to that effect and shall promptly resume such performance.

13.4 Payment. Contractor will continue to receive payment of Reimbursable Costs incurred, notwithstanding the occurrence of a Force Majeure Event.

## ARTICLE 14

## MECHANICAL COMPLETION AND FINAL COMPLETION

14.1 Mechanical Completion. For all Work performed or provided by Contractor, Contractor will notify Owners' Authorized Representative in writing when it believes Mechanical Completion of a Unit has been achieved. Within thirty (30) Days after such notification, Owners will inspect the Work and either (i) confirm that Mechanical Completion has been achieved or (ii) set forth to Contractor the reasons that preclude acknowledgement of Mechanical Completion (which may take the form of a list of items of Work that Owners believe remain to be completed in order for Mechanical Completion to be achieved). This process will be repeated as may be required until Owners confirm that Mechanical Completion has been achieved.

14.2 Unit Mechanical Completion Requirements. The requirements for achieving Mechanical Completion for each Unit are set forth in Exhibit G. For purposes of determining both Mechanical Completion and Punch List items, Shared Facilities shall be considered part of Unit 3.

14.3 Punch List. Prior to Mechanical Completion of a Unit, Contractor shall submit to Owners for their review and approval a comprehensive list of remaining Work, limited to items of a minor nature, that Contractor proposes will not prevent the Unit from achieving Mechanical Completion (the "Punch List"). Owners will review the Punch List and provide Contractor with comments and additions thereto within thirty (30) Days from the date of submission of the Punch List to Owners, provided that Punch List items may continue to be added through the date of confirmation of Mechanical Completion per Section 14.2, and after Mechanical Completion for both Units with respect to Work Packages not required for Mechanical Completion and not complete as of Mechanical Completion.

14.4 Final Completion. Contractor shall diligently complete all remaining Work (including all Work Packages not required to attain Mechanical Completion) and the Punch List items to the reasonable satisfaction of Owners, provided that Contractor will coordinate its remaining Work and work on Punch List items so as not to interfere with Owners commissioning and startup activities. Final Completion will be achieved after the Punch List items have been fully completed and all other remaining Work (other than Commissioning and Startup Support per Section 2.10) has been completed.

## ARTICLE 15

## WARRANTY

15.1 Warranty Provided.

15.1.1 Contractor warrants during the Warranty Period for a Unit that the Work performed by Contractor and its Subcontractors with respect to such Unit shall:

(i) comply with the Issued For Construction Documents;

(ii) conform to the requirements of this Agreement, including the Performance Standards; and

(iii) comply with applicable Laws.

15.1.2 The warranties set forth in this Section 15.1 are collectively referred to as the "Warranties."

15.2 Remedy.

15.2.1 Upon being notified during the Warranty Period for a Unit that any portion of the Work performed by Contractor and its Subcontractors for such Unit fails to comply with the

Warranties (a "Warranty Issue"), Contractor shall remedy such Warranty Issue at its sole cost and expense, as follows:

(i) Contractor shall Promptly either re-perform, repair or replace the non-complying Work;

(ii) Such remedy shall include all disassembly and reassembly of components and systems of the Facility, and the removal and reinstallation of Facility components, that may be required in order to re-perform, repair or replace the non-complying Work; and

(iii) Such remedy shall include performing such tests as are reasonably necessary to demonstrate the adequacy and effectiveness of the remedy.

15.2.2 If Contractor, after receiving notice from Owners of a Warranty Issue during the Warranty Period, fails to Promptly remedy any noncomplying Work in accordance with this Article, then Owners may remedy such Warranty Issue, or have such Warranty Issue remedied by others, and Contractor agrees to promptly reimburse Owners for all reasonable expenses incurred to remedy such Warranty Issue.

15.2.3 For purposes of this Article, "Promptly" means, when the applicable Unit is not in an outage state, the commencement of reperformance, repair or replacement within thirty (30) Days after receiving notice of the non-compliance from Owners, and diligent pursuit to full completion thereafter; provided that:

(i) a Warranty Issue resulting in a Unit outage shall be corrected on an emergency, as soon as physically feasible basis;

(ii) Contractor shall use reasonable efforts to remedy Warranty Issues at a time responsive to and consistent with the Owners' requirements for the safe, reliable and efficient operation of the Facility in accordance with Owners' operational requirements and needs; and

(iii) at Owners' option, the remedy of a Warranty Issue may be deferred until the time of the Unit's next regularly scheduled refueling outage, notwithstanding that such outage occurs after the end of the Warranty Period; provided that the opportunity to remedy the Warranty Issue during the next outage is provided no later than twenty-one (21) months following the end of the Warranty Period.

15.3 Warranty Period. The "Warranty Period" with respect to each Unit will commence upon the Ready for Fuel Load Date of such Unit and will expire on the later of: (i) the date that is twenty-four (24) months after such Ready for Fuel Load Date; or (ii) twelve (12) months after the Commercial Operation Date of such Unit; provided, however, that the Warranty Period with respect to a Unit shall in any event expire on the date that is thirty-six (36) months after the Ready for Fuel Load Date for such Unit.

15.4 Warranty Period Extension. Any Work re-performed, repaired or replaced in satisfaction of Contractor's obligations in connection with the Warranty will be re-warranted by Contractor pursuant to the same Warranties set forth in Section 15.1, and Contractor will have the same obligations in relation thereto as set forth in Section 15.2.1, for a period equal to the longer of: (i) one (1) year from the date such re-performance, rework, repair or replacement is completed; and (ii) the remaining period under the original Warranty Period; provided that such re-warranty shall not in any event extend beyond thirty-six (36) months after the Ready for Fuel Load Date of the applicable Unit.

15.5 Significant Construction Defects Prior to Warranty Period. Costs incurred for the correction of defects or deficiencies in the Work prior to the commencement of the Warranty Period for either Unit shall be Reimbursable Costs, except that costs incurred by Contractor and/or its Subcontractors for the correction of Significant Construction Defects prior to the commencement of the Warranty Period for either Unit shall be Non-Reimbursable Costs, subject to the limitations herein:

(i) Owners will notify Contractor promptly after becoming aware of a construction defect that Owners consider is or is likely to be a Significant Construction Defect; and

(ii) The Non-Reimbursable Costs to be borne by Contractor and Affiliate Subcontractors on account of the correction of a Significant Construction Defect will be limited to an amount of [***] per Significant Construction Defect; and

(iii) The Non-Reimbursable Costs to be borne by Contractor and Affiliate Subcontractors on account of the correction of Significant Construction Defects will be subject to the Defects Subcap limitation set forth in Section 15.6.1.

15.6 Liability Limitations Relating to Warranties and Defects.

15.6.1 CONTRACTOR'S CUMULATIVE AGGREGATE LIABILITY FOR THE FAILURE OF THE WORK TO COMPLY WITH THE WARRANTIES SET FORTH IN SECTION 15.1 AND FOR THE COST OF CORRECTION OF SIGNIFICANT CONSTRUCTION DEFECTS PURSUANT TO SECTION 15.5 SHALL NOT EXCEED [***] (the "DEFECTS SUBCAP"). To the extent that Contractor incurs (or is charged by Owners per Section 15.2.2) costs in excess of the Defects Subcap in performing its remedy obligations under Section 15.2, such costs shall be treated as Reimbursable Costs, but shall not entitle Contractor to any adjustment in the Fee.

15.6.2 For purposes of determining whether the Defects Subcap has been reached, the following amounts shall be excluded:

(i) amounts received by Contractor from any Third Party in the form of damages paid or otherwise in connection with any Warranty Issue;

(ii) proceeds received by Contractor or any Subcontractor from any insurance coverage required by this Agreement with respect to any Warranty Issue;

(iii) costs to remedy any Warranty Issue or Significant Construction Defects that were borne by Subcontractors, other than Affiliate Subcontractors; and

(iv) costs to remedy any Warranty Issue to the extent such Warranty Issue results from the Willful Misconduct of Contractor, provided that Contractor's liability for such costs shall in any event be subject to Section 18.2 and the other liability protections set forth in this Agreement. For the purpose hereof, "Willful Misconduct" means an act or failure to act on the part of Contractor which evidences either an intent to cause the loss or damage resulting therefrom or such conscious recklessness as to the harmful consequences of such act or failure to act that such conduct amounts to intentional misconduct.

15.6.3 THE WARRANTIES SET FORTH IN THIS AGREEMENT ARE EXCLUSIVE AND IN LIEU OF ALL OTHER WARRANTIES, EXPRESS OR IMPLIED, FOR PERFORMANCE, MERCHANTABILITY, FITNESS FOR A PARTICULAR PURPOSE, OR OTHERWISE. THERE ARE NO OTHER WARRANTIES, AGREEMENTS, ORAL OR WRITTEN, OR UNDERSTANDINGS WHICH EXTEND BEYOND THOSE SET FORTH IN THIS AGREEMENT.

15.6.4 CONTRACTOR SHALL NOT HAVE ANY LIABILITY FOR ANY DEFECT THAT PERTAINS TO ANY ASPECT OF THE FACILITY THAT IS OUTSIDE THE CONTRACTOR'S SCOPE OF WORK REQUIRED TO BE PERFORMED UNDER THIS AGREEMENT. SPECIFICALLY, CONTRACTOR SHALL NOT HAVE ANY LIABILITY RELATED TO THE DESIGN OR THE ENGINEERING OF THE FACILITY, PLANT EQUIPMENT OR MATERIALS SUPPLIED BY OR ON BEHALF OF OWNERS, WORK PERFORMED BY OTHER CONTRACTORS (OTHER THAN CONTRACTOR OR ITS SUBCONTRACTORS), OR WORK COMPLETED PRIOR TO THE EFFECTIVE DATE.

15.6.5 WITHOUT LIMITING ANY OTHER CONTRACTOR LIABILITIES UNDER THIS AGREEMENT, CONTRACTOR'S SOLE LIABILITY RELATED TO DEFECTS IN THE WORK SHALL BE LIMITED TO CONTRACTOR'S LIABILITIES PURSUANT TO SECTIONS 15.2, 15.4 AND 15.5.

## ARTICLE 16

## INDEMNITY

16.1 Third Party Claims .

16.1.1 Except with respect to a Nuclear Incident, and without regard to any insurance proceeds actually received, Contractor shall indemnify, defend and hold harmless Owners and Owners' Interests from and against any and all Third Party Claims and Affiliate Subcontractor Claims arising or resulting from:

(i) any injury of or death to natural persons or damage to or destruction of Third Party or Affiliate Subcontractor property to the extent arising or resulting from the fault, negligent acts or negligent omissions or willful misconduct of Contractor or its Subcontractors or any Personnel of the foregoing;

(ii) fines, penalties or other similar amounts required to be paid to Government Authorities to the extent resulting from any violation of Law by Contractor or its Subcontractors, whether caused by the acts or omissions of Contractor, any of its Subcontractors, or their respective Personnel; or

(iii) (a) the Release on or from the Site or any other location of any Hazardous Materials brought onto the Site by Contractor or its Subcontractors to the extent caused by the fault or the negligent acts or negligent omissions or willful misconduct of Contractor, its Subcontractors, or any Personnel of the foregoing, (b) the Release on or from the Site of any Hazardous Materials brought onto the Site by Owners for the Work to the extent such Release is caused by the fault or the negligent acts or omissions or willful misconduct of Contractor, its Subcontractors, or any Personnel of the foregoing or (c) contamination of the environment or injury to natural resources resulting from Hazardous Materials brought onto the Site by Contractor or its Subcontractors or brought onto the Site by Owners for the Work to the extent caused by the negligent acts or negligent omissions or willful misconduct of Contractor, its Subcontractors, or any Personnel of the foregoing.

16.1.2 Except with respect to a Nuclear Incident, Owners shall indemnify, defend and hold harmless Contractor and Contractor Interests from and against any and all Third Party Claims associated with any injury of or death to natural persons or damage to or destruction of Third Party property, other than Contractor-provided Construction Equipment and any other property belonging to or leased by Contractor, its Subcontractors or the Personnel or Invitees of any of them, to the extent arising or resulting from the fault or the negligent acts or negligent omissions or willful misconduct of Owners or its Personnel (other than Contractor or its Personnel) or the employees or agents of the foregoing.

16.1.3 Owners shall indemnify, defend and hold harmless Contractor and Contractor Interests from and against any and all liability, damage, cost, expense and loss (including reasonable attorneys' fees, expenses and court costs), attributable or relating to any employment-related claim that arose or accrued at the Site prior to the Effective Date. “Employment related claims” for purposes of this provision include any and all breach of contract claims, tort claims, constitutional claims, equitable claims, harassment, discrimination, or retaliation claims, grievances under any collective bargaining agreement or national labor agreement, claims of wrongful or constructive discharge, claims for breach of an express or implied employment contract, defamation claims (including libel and slander), wage claims, claims under Title VII of the Civil Rights Act, 42 U.S.C. § 1981, the Equal Pay Act, the Energy Reorganization Act, the Davis-Bacon Act, the False Claims Act, the Rehabilitation Act, the Americans with Disabilities Act, the Family and Medical Leave Act, the Age Discrimination in Employment Act, the Occupational Safety and Health Act, the Employee Retirement Income Security Act, the Fair Labor Standards Act, the Sarbanes Oxley Act, Consolidated Omnibus Budget Reconciliation Act, Immigration Reform and Control Act, any state’s human rights Law, any state's labor Law, the non-discrimination and/or retaliation provisions of any state workers' compensation Law and any and all other applicable local, state, and federal common law claim, statute, regulation or public policy relating to employment.

16.2 Limitation of Liability for Damage to Property . OWNERS HEREBY RELEASE AND SHALL INDEMNIFY, DEFEND AND HOLD HARMLESS CONTRACTOR AND CONTRACTOR INTERESTS FROM AND AGAINST ANY CLAIMS, DAMAGES AND LIABILITIES ASSOCIATED WITH DAMAGE TO OR AND DESTRUCTION OF THE FACILITY OR PLANT EQUIPMENT AND MATERIALS INTENDED FOR INCORPORATION IN THE FACILITY OR VEGP UNITS 1 AND 2, EXCEPT THAT TO THE EXTENT THAT CONTRACTOR, ITS SUBCONTRACTORS, OR THEIR RESPECTIVE PERSONNEL, AS A RESULT OF THEIR FAULT, NEGLIGENCE, OR WILLFUL MISCONDUCT, CAUSE ANY DAMAGE TO ANY PROPERTY OF THE OWNERS (INCLUDING VEGP UNITS 1 AND 2 AND THE UNITS) THAT DOES NOT ARISE OUT OF OR RESULT FROM A NUCLEAR INCIDENT, CONTRACTOR SHALL BE SOLELY RESPONSIBLE FOR AND SHALL PAY FOR SUCH LOSS OR DAMAGE UP TO [***] PER OCCURRENCE. THE PARTIES DO NOT INTEND SUCH PROVISIONS TO BE FOR THE BENEFIT OF ANY THIRD PARTY, INCLUDING ANY INSURER.

16.3 Intellectual Property Indemnity . Contractor shall indemnify, defend and hold harmless Owners and Owners' Interests and any of their respective Personnel against any Third Party Claim and Affiliate Subcontractor Claim to the extent based on a Claim that any Work constitutes an infringement or misappropriation of any intellectual property rights of any Third Party or any Affiliate Subcontractor including, any U.S. patents, copyrights, trade secrets, trademark rights, confidentiality rights or other intellectual property rights and, if timely notified in writing and given authority and reasonable assistance for the defense of same, Contractor shall pay the damages, liabilities, costs, losses and expenses (including attorneys' fees) awarded therein against Owners. If a Claim of infringement is made, Contractor may, or if the use of the item is enjoined, Contractor shall, at its expense and option, (a) procure for Owners the right to continue using such item, (b) replace such item with a non-infringing item that meets the requirements of this Agreement, or (c) modify such item such that it becomes non-infringing while still meeting the requirements of this Agreement. These provisions do not apply to the extent the infringement or misappropriation is the result of items (including engineering deliverables and Plant Equipment and Materials) furnished to Contractor hereunder or to the extent that the infringement or misappropriation is the result of any Work performed hereunder being modified or combined with items not furnished by Contractor or its Subcontractors. If a suit or proceeding is brought against Contractor or any of its Subcontractors in respect of any alleged infringement or misappropriation described in the preceding sentence, Owners shall protect Contractor and its Subcontractors to the same extent that Contractor has agreed to protect Owners in this Section 16.3.

16.4 Nuclear Indemnity and Insurance . Owners shall obtain and maintain "financial protection" and an "indemnification agreement" for protection against liability for Nuclear Incidents (including master worker coverage), both in such form and amount as shall satisfy the requirements of Section 170 of the Atomic Energy Act of 1954, as amended. In the event that the nuclear liability protection contemplated by Section 170 of the Atomic Energy Act of 1954, as amended, is repealed, changed, or is not renewed, Owners shall maintain in effect liability protections through governmental indemnity, limitation of liability and/or insurance of comparable coverage which shall not result in a material impairment of the protection afforded to Contractor by such nuclear liability protection which is in effect as of the Effective Date. Other than the foregoing, in no event shall Owners have any liability or obligation to Contractor or Contractor Interests with respect to off-site liability resulting from a Nuclear Incident.

16.5 Indemnity Procedures .

16.5.1 The indemnifying Party under this Article 16 or any other indemnity provision of this Agreement shall have the right to conduct and control, through counsel of its own choosing, reasonably acceptable to the indemnified Party, the defense of any Claim for which it has an indemnity obligation hereunder. The indemnifying Party shall keep the indemnified Party fully informed in the conduct of the proceeding.

16.5.2 The indemnified Party may, at its election, participate in the defense thereof at its sole cost and expense; provided, however, that if (i) the indemnifying Party shall fail to defend any Claim for which it has an indemnity obligation hereunder, (ii) the Parties mutually agree in writing to allow the indemnified Party to assume the defense of such Claim and forego any indemnity claimed under this Article, (iii) in the reasonable opinion of legal counsel for the indemnified Party, such Claim involves the potential imposition of a criminal liability on the indemnified Party, its directors, officers, employees or agents, or (iv) in the reasonable opinion of legal counsel for the indemnified Party, an actual or potential conflict of interest exists where it is advisable for such indemnified Party to be represented by separate counsel, then the indemnified Party shall be entitled to control and assume responsibility for the defense of such Claim, at the cost and expense of the indemnifying Party. The indemnifying Party may, in any event, participate in such proceedings at its own cost and expense. The indemnified Party shall not have the right to settle without the written consent of the indemnifying Party (which consent shall not be unreasonably withheld).

16.5.3 The indemnifying Party, in the defense of any such litigation, other proceeding or other Claim, shall have the right in its sole discretion to settle a Claim for which it has an indemnity obligation hereunder only if (i) settlement involves only the payment of money and execution of appropriate releases of the indemnified Party, (ii) there is no finding or admission of any violation of Law or violation of the rights of the indemnified Party, and (iii) the indemnified Party will have no liability with respect to such compromise or settlement. Otherwise, no such Claim shall be settled or agreed to without the prior written consent of the indemnified Party, which shall not be unreasonably withheld.

16.5.4 The indemnified Party and the indemnifying Party (i) shall fully cooperate in good faith in connection with such defense and shall cause their legal counsel and accountants to do the same, (ii) shall make available to the other Party the relevant books, records, and information (in such Party’s control) during normal business hours, and (iii) shall furnish to each other, at the indemnifying Party’s expense, such other assistance as the other Party may reasonably require in connection with such defense, including making employees of the indemnified Party available to testify and assist others in testifying in any such proceedings.

16.6 Survival of Indemnity Obligations . This Article 16 and the indemnity obligations set forth in the other provisions of this Agreement shall survive the completion of the Work and the termination of this Agreement. For purposes of clarification hereunder, without limiting the other rights granted hereunder to either Party, a Party may enforce the indemnity provisions hereunder without having to declare a Contractor Event of Default or an Owner Event of Default (as applicable).

## ARTICLE 17

## INSURANCE

17.1 Owners Insurance Obligations .

17.1.1 The Owners will procure and maintain the following insurances:

(i) Builder's Risk Insurance with total limits of [***], subject to applicable sublimits, including coverage for resultant damage due to any defects in equipment and/or material and/or faulty workmanship, and maintenance coverage for duration of the Warranty Period unless otherwise insured by Owners' Operating Property coverages; subject to customary or industry standard exceptions and exclusions;

(ii) Commercial General Liability with combined single limit of [***] each occurrence, [***] aggregate including broad form contractual liability, independent contractors, personal injury, incidental medical malpractice, and products and completed operations for at least eight (8) years following final acceptance of the Work;

(iii) Contractors Pollution Liability Insurance with limits of [***] each occurrence, and [***] aggregate on a project basis, and occurrence form, that provides appropriate coverage, including coverage for the following: (i) bodily injury, sickness, disease, mental anguish or shock sustained by any person, including death; (ii) property damage including physical injury to or destruction of tangible property including the resulting loss of use thereof, clean-up costs, and the loss of use of tangible property that has not been physically injured or destroyed; (iii) defense costs including costs, charges and expenses incurred in the investigation, adjustment or defense of claims for such compensatory damages, and (iv) contractual liability third-party coverage for bodily injury, property damage, defense, and cleanup, whether sudden/accidental and/or gradual arising from activities performed by Contractor, and/or Contractor Interests. Such coverage shall continue for a period to be agreed by Owner and Contractor after the termination of this Agreement.

(iv) Workers' Compensation Insurance with limits and coverage as required by any applicable law or regulation both State and/or Federal including U.S.L. & H.W. Compensation Act.

(v) Employer's Liability Insurance, including "all States" endorsement and when required Marine Employer's Liability and Jones Act coverage, of not less than [***] each accident for bodily injury by accident; [***] each employee for bodily injury by disease; and [***] bodily injury by disease policy limit.

(vi) Excess Liability on a follow form basis including products and completed operations with a coverage limit of [***];

(vii) Nuclear and Non-Nuclear Property Insurance;

(viii) Open Cargo Insurance protecting materials and equipment during transit and while stored away or on the project site; and

(ix) Commercial Automobile Liability Insurance shall be obtained, including owned, hired, and non-owned automotive equipment in connection with the insureds operation with an insured combined single limit for bodily injury and property damage of [***] each occurrence.

17.1.2 The insurances 17.1.1 (i) through 17.1.1 (viii) shall include Contractor, Contractor Interests and Subcontractors as additional insureds, be primary and non-contributory and include an insurer's waiver of subrogation.

17.1.3 It is understood that Owners sponsor an Owner Controlled Insurance Program ("OCIP"), as the mechanism for providing Commercial General Liability, Statutory Workers Compensation including Employers Liability insurance covering activities of Contractor and Contractor Interests and Subcontractors in performance of the Work including Site, declared off-site locations, incidental off-site activities, including travel between covered sites and/or travel in conjunction to Work activities, and/or conducted in fulfillment of the Work by Contractor and Contractor Interests and Subcontractors. The OCIP insurances are provided at no cost to Contractor and/or Contractor Interests and Subcontractors, including deductibles and/or contribution to self-insured retentions. If, and for any reason, Owners' are unable to furnish any of the OCIP coverages, and or coverage 17.1.1(iii), (vi) and or (viii), or elects to discontinue the aforementioned insurances, modifies the limits of liability provided, or coverage limits are found inadequate due to claim erosion, or Owner and or Insurers request that Contractor or any of Contractor Interests or Subcontractors withdraw from the insurances, Contractor or any of its enrolled Subcontractors will obtain at Owners' expense and thereafter maintain, at Owners' expense such insurances.

17.1.4 With respect to insurances 17.1.1 (i), (ii), (iii), (iv), (v), (vi) and (viii) Contractor will be allowed to participate in the claims reporting, management and claim cost analysis, including the provision of regular detailed loss information and will take part in insurer claim reviews, and will be consulted regarding the selection of counsel with respect to claims and litigation.

17.2 Contractor's Insurance Obligations .

17.2.1. Contractor will provide the following insurance coverages:

(i) Commercial General Liability with minimum combined single limit of [***] each occurrence, [***] aggregate including broad form contractual liability, independent contractors, personal injury, arising from activities unrelated to the Work;

(ii) Workers' Compensation Insurance with limits and coverage as required by any applicable law or regulation both State and/or Federal including U.S.L. & H.W. Compensation arising from activities unrelated to the Work;

(iii) Employer's Liability Insurance, including "all States" endorsement and when required Marine Employer's Liability and Jones Act coverage, of not less than [***] each accident for bodily injury by accident; [***] each employee for bodily injury by disease; and [***] bodily injury by disease policy limit., arising from activities unrelated to the Work;

(iv) Commercial Automobile Liability Insurance shall be obtained, including owned, hired, and non-owned automotive equipment in connection with the insureds operation with an insured combined single limit for bodily injury and property damage of [***] each occurrence;

(v) Excess Liability with a limit of [***] per occurrence and in the aggregate, arising from activities unrelated to the Work, in the excess of the limits of the underlying Commercial General Liability, Commercial Automobile Liability, and Employer's Liability insurance policies. The required limits may be satisfied by a combination of a primary policy and an excess or umbrella policy;

(vi) Contractor's Equipment Coverage in the amount of the value of the equipment through insurance or self-insurance; and

(vii) Employment Practices Liability with a coverage limit of [***] per occurrence and in the aggregate on a project basis.

17.2.2. Contractor shall name Owners, as additional insureds (except for Workers' Compensation and Employment Practices Liability) but only for their vicarious liability arising from Contractor's negligent operations, and provide a waiver of subrogation on all policies.

17.2.3. Contractor will enroll, and will support enrollment of Contractor Interests and Subcontractors in the OCIP and observe to extent possible requirements outlined in the OCIP manual, including monthly payroll reporting.

17.2.4. In addition to OCIP enrollment obligation, Contractor will require Subcontractors to maintain the insurances listed in this Section 17.2 as applicable.

a. Mutual Coverage Obligations .

17.3.1. Within ten (10) Days after the Effective Date and prior to the commencement of any Work, each Party shall have on file with the other Party the applicable insurance certificate(s). The Parties shall provide thirty (30) days written notice to the other Party prior to any material change or cancellation of the insurance.

17.3.2. All insurance shall be placed with insurers rated by A.M. Best Company no less than A-VII and authorized to do business in the state where the Work is to be performed, unless Owner and Contractor mutually agreed otherwise.

## ARTICLE 18

## LIMITATIONS OF LIABILITY

18.1 No Consequential Damages . IN NO EVENT SHALL CONTRACTOR OR CONTRACTOR INTERESTS OR OWNERS OR OWNERS' INTERESTS BE LIABLE, WHETHER BASED ON CONTRACT (INCLUDING BREACH, WARRANTY, INDEMNITY, ETC.) OR TORT (INCLUDING FAULT, NEGLIGENCE AND STRICT LIABILITY), OR OTHERWISE, UNDER ANY WARRANTY OR OTHERWISE, RELATING TO OR ARISING OUT OF THE WORK OR THIS AGREEMENT, FOR ANY CONSEQUENTIAL, INDIRECT, SPECIAL, PUNITIVE, OR INCIDENTAL LOSS, DAMAGE OR INJURY, INCLUDING ANY SUCH DAMAGES WHICH RESULT FROM LOSS OF USE OF PROPERTY, EQUIPMENT OR SYSTEMS, LOSS BY REASON OF FACILITY SHUTDOWN OR SERVICE INTERRUPTION, COSTS OF CAPITAL OR EXPENSES THEREOF, LOSS OF PROFITS OR REVENUES OR THE LOSS OF USE THEREOF, LOST BUSINESS OPPORTUNITY, OR COST OF PURCHASED OR REPLACEMENT POWER (INCLUDING ADDITIONAL EXPENSES INCURRED IN USING EXISTING POWER FACILITIES) OR FROM CLAIMS OF CUSTOMERS. The limitation of liability under this Section 18.1 shall not apply to: (i) amounts Claimed by Third Parties or Affiliate Subcontractors which are subject to the indemnification obligations under this Agreement; or (ii) any loss or damages to the extent insurance proceeds are received from the insurance required under this Agreement, it being the Parties specific intent that the limitations of liability hereunder shall not relieve the insurers' obligations for such insured risks; or (iii) amounts expressly payable to Contractor under Article 7, Article 8, or Article 21 of this Agreement; and (iv) amounts expressly payable by Contractor under Article 8, Section 15.2.2, Article 20, or Article 21 of this Agreement.

18.2 Maximum Total Liability . NOTWITHSTANDING ANY OTHER PROVISION TO THE CONTRARY, CONTRACTOR'S AND CONTRACTOR INTERESTS' CUMULATIVE AGGREGATE LIABILITY, ARISING OUT OF OR IN CONNECTION WITH THE WORK OR THIS AGREEMENT, WHETHER BASED ON CONTRACT (INCLUDING BREACH, WARRANTY, INDEMNITY, ETC.), TORT (INCLUDING FAULT, NEGLIGENCE OR STRICT LIABILITY) OR OTHERWISE TO OWNERS SHALL NOT EXCEED AN AMOUNT EQUAL TO [***]. The limitation of liability under this Section 18.2 shall not apply to: (i) amounts Claimed by Third

Parties or Affiliate Subcontractors which are subject to Contractor's indemnification obligations under this Agreement; or (ii) any loss or damages to the extent insurance proceeds are received from the insurance required to be obtained by Contractor or its Subcontractors under this Agreement, it being the Parties specific intent that the limitations of liability hereunder shall not relieve the insurers' obligations for such insured risks.

18.3 Dalton .

18.3.1 For all purposes of this Agreement:

(i) the term "Dalton Utilities" shall mean only the utility company, property and assets operated by the Board of Water, Light and Sinking Fund Commissioners of the City of Dalton, Georgia d/b/a Dalton Utilities, its successors, successors-in-title or assigns, including without limitation any successors to the business of Dalton Utilities; and

(ii) the term "Dalton Utilities Assets" shall mean collectively (A) all property or assets of Dalton Utilities, including without limitation all electric power generation, transmission and distribution assets owned or operated by the City of Dalton and contract rights and receivables related thereto, which now or at any time in the future are owned, used or operated by Dalton Utilities, and such property and assets shall include without limitation any sale, insurance, condemnation or other proceeds with respect to such property and assets; and (B) all accounts receivable, debts, income or other amounts owed to Dalton Utilities.

18.3.2 Notwithstanding any other term or provision of this Agreement to the contrary, the Parties hereby agree that:

(i) if any Party obtains any money judgment against Dalton Utilities because of Dalton Utilities' default under this Agreement or breach by Dalton Utilities of any representation or warranty under this Agreement, such Party's sole remedy to satisfy the judgment shall be to levy against and sell, and/or garnish or otherwise realize upon, any and all of the Dalton Utilities Assets;

(ii) payments of all amounts of any kind or nature whatsoever that may at any time be due and owing by Dalton Utilities pursuant to the terms of, or resulting from, this Agreement shall be payable solely out of the Dalton Utilities Assets and shall not be payable from any other source, including without limitation the "General Fund" of the City of Dalton;

(iii) no such payments shall be, or be deemed to be, a debt of the City of Dalton under any circumstance or for any purpose whatsoever, nor shall this Agreement constitute a pledge of the full faith and credit of the City of Dalton, nor shall the City of Dalton appropriate or be required to appropriate funds to pay for any amounts due under this Agreement;

(iv) no Party will ever have the right to compel the exercise of any taxing power of the City of Dalton to pay any amount due from Dalton Utilities under this Agreement, nor to enforce payment thereof against any property of the City of Dalton other than the Dalton Utilities Assets;

(v) no Party shall have any recourse for payment hereunder against any source of funds of the City of Dalton other than the Dalton Utilities Assets, and each Party hereby irrevocably and unconditionally waives any recourse or claim it may or could otherwise have or allege to have against any payment source of the City of Dalton other than the Dalton Utilities Assets; and

(vi) no provision of this Agreement is intended to, nor shall any such provision in any way (A) grant, convey or otherwise extend to any Party any lien, encumbrance or other charge against the Dalton Utilities Assets, or (B) modify, impair, subordinate or otherwise affect the rights, obligations and privileges of Dalton Utilities arising under the City of Dalton, Georgia Combined Utilities Revenue Bonds, Series 2017, or any other obligation of Dalton Utilities, it being understood and agreed that the revenues of Dalton Utilities and all funds created and maintained pursuant to any ordinance enacted for the purpose of issuance of any such bonds are subject to a prior and superior lien to secure such bonds, and shall not be subject to levy, seizure or other adverse action as may constitute a default with respect to such bonds.

## ARTICLE 19

## PERFORMANCE SECURITY

19.1 Contractor Parent Guarantee .

19.1.1 Simultaneously with the execution of this Agreement, Contractor shall furnish (and thereafter maintain) a parent company guarantee substantially in the form attached as Exhibit R, whereby Bechtel Nuclear, Security & Environmental, Inc. (“Contractor Guarantor”) guarantees the payment obligations of Contractor under this Agreement, as the same may be amended, supplemented or otherwise changed in accordance with the provisions of this Agreement (“Parent Company Guarantee”).

19.1.2 Owners shall be entitled to make a demand against the security provided by Contractor under Section 19.1.1 in the event that Contractor has failed to make a payment when due pursuant to the provisions of this Agreement or in order to recover any damages to which Owners are otherwise entitled under this Agreement as a result of Contractor’s failure to satisfy any of its obligations under this Agreement, whether or not a Contractor Event of Default has been declared.

19.2 Owner Performance Security .

19.2.1 In the event that an Owner experiences a Security Posting Condition, the Owner experiencing such Security Posting Condition shall, within ten (10) Business Days thereafter, provide to Contractor and maintain an Eligible Letter of Credit or Cash Security in an amount equal to the product of: (i) such Owner's Ownership Interest; and (ii) the Owner Security Amount ("Owner Security"). The Owner providing the security shall have the right to select whether it will post Cash Security or an Eligible Letter of Credit. If at any time Owner Security held by Contractor exceeds the amount required hereunder, Contractor shall refund the excess Cash Security held or permit the applicable Owner to replace or amend the Eligible Letter of Credit so that the amount of the Owner Security held by Contractor is equal to the amount required by the provisions of this Section 19.2.1

19.2.2 Within three (3) Business Days after the cessation of a Security Posting Condition with respect to an Owner and Owner's notification to Contractor thereof, or upon such Owner's satisfaction of all of its payment obligations under this Agreement, Contractor shall return to such Owner Security previously provided to Contractor.

19.2.3 Contractor shall only be permitted to draw upon or utilize Owner Security as follows:

(i) Contractor may draw upon or utilize Owner Security provided by an Owner in the event that such Owner has failed to make a payment when due pursuant to the provisions of this Agreement.

(ii) If at any time an Eligible Letter of Credit provided by an Owner is within sixty (60) Days of expiration or termination (such sixtieth ($60^{th}$) Day being the "Renewal Date") and such Owner is still required to provide Owner Security under Section 19.2.1, and a substitute or replacement Owner Security that satisfies the requirements of this Agreement has not been provided by the Day that is fourteen (14) Days after the Renewal Date, Contractor shall be entitled to draw upon the full amount of the Eligible Letter of Credit.

19.2.4 Contractor may draw upon Owner Security as provided in Section 19.2.3 regardless of whether Owner Event of Default has been declared.

## ARTICLE 20

## LIENS

20.1 Liens. Contractor shall keep the Facility, the Plant Equipment and Materials and the Site free from Liens of Contractor, its Subcontractors and any of their Personnel (other than Liens arising from acts of Owners or Owners' breach of its obligation hereunder to make payments to Contractor), and shall promptly notify Owners of any such Liens against the Facility, the Plant Equipment and Materials or the Site and any structures comprising the Facility or located on the Site filed by Contractor or a Subcontractor or any of their respective Personnel. Contractor shall indemnify, defend and hold harmless Owners from any Lien placed against Owners' property by any Subcontractor or their Personnel including those arising from nonpayment to any Subcontractor or their Personnel in connection with the Work; provided that such Lien is not the result of Owners' breach of their payment obligations under this Agreement.

20.2 Discharge or Bond . Contractor shall take prompt steps to discharge or bond any Lien filed against the Facility, the Plant Equipment and Materials, the Site and any structures comprising the Facility or located on the Site by any Subcontractor or its Personnel (other than Liens arising from acts of Owners or Owners' breach of its obligation hereunder to make payments to Contractor). If Contractor fails to discharge or promptly bond any Lien, in addition to any other rights of Owners under this Agreement, Owners shall have the right, upon notifying Contractor in writing and providing Contractor reasonable time to indemnify, discharge or bond the Lien, to take reasonable actions and steps to satisfy, defend, settle or otherwise remove the Lien at Contractor's expense, including reasonable attorneys' fees, costs and expenses. Owners shall have the right to recover these expenses from Contractor. Contractor shall have the right to contest any Lien, provided it first provides to the lien holder, a court or other third Person, as applicable, a bond or other assurances of payment necessary to remove the Lien related to the Work from the Site and the Facility in accordance with the Laws of the State of Georgia.

## ARTICLE 21

## SUSPENSION AND TERMINATION

21.1 Suspension by the Owners for Convenience .

21.1.1 On giving reasonable prior notice, Owners may, without cause and for any reason, order Contractor in writing to suspend (including delay or interrupt) the Work in whole or in part without terminating the Agreement and for such period of time as the Owners may determine ("Suspension Order"). Upon receipt of a Suspension Order, Contractor shall promptly suspend its performance of the Work as directed by Owner but shall take reasonable precautions to protect, store and secure the Plant Equipment and Materials on the Construction Site against deterioration, loss or damage. Contractor shall resume promptly any suspended Work following receipt of a written notice from Owners to do so.

21.1.2 During any period of suspension, delay or interruption ordered by Owners under Section 21.1.1, Contractor will use commercially reasonable efforts to mitigate Reimbursable Costs to the extent that performance of Work is suspended, delayed or interrupted; provided that Contractor will continue to receive payment of Reimbursable Costs incurred during such period.

21.1.3 In the event that (i) any period of suspension, delay or interruption of the Work ordered by Owners under Section 21.1.1 continues for a consecutive period of one hundred eighty (180) Days; or (ii) any period of suspension, delay or interruption under Section 21.1.1 when combined with other period(s) of suspension, delay or interruption under Section 21.1.1 exceeds a cumulative aggregate of one two hundred seventy (270) Days, then Contractor shall thereafter be entitled to terminate this Agreement by providing notice to the Owners for so long as such suspension, delay or interruption is continuing. Such termination shall be treated as a termination for convenience by Owners under Section 21.3.

21.2 Contractor Event of Default .

21.2.1 Owners may declare a Contractor Event of Default upon notice to Contractor of the occurrence of any of the following (each a "Contractor Event of Default"):

(i) Contractor is in breach of a material provision of this Agreement (other than the matters addressed in the other subsections of this Section 21.2.1) and fails to cure the breach within thirty (30) Days following notice of such breach or, if such breach is not capable of being cured within such thirty (30) Day period, such longer period as is reasonably necessary but in no event longer than ninety (90) Days following notice of such breach so long as Contractor has commenced the cure within such thirty (30) Day period and thereafter diligently pursues the cure;

(ii) Contractor has Abandoned the Work and Owners have provided Contractor notice that Contractor has Abandoned the Work;

(iii) Contractor or Contractor Guarantor is Insolvent;

(iv) Contractor fails to comply with the requirements of Section 19.1 or Contractor Guarantor breaches any of its obligations under the Parent Company Guarantee or if any representation or warranty made by Contractor Guarantor in the Parent Company Guarantee shall prove to be incorrect in any material respect when made, unless any of the foregoing is cured by the end of the second Business Day following receipt of a written notice from Owners of a failure under this Section 21.2.1(iv);

(v) Contractor fails to provide a Repayment Letter of Credit as required under this Agreement unless such failure is cured by the end of the seventh ($7^{th}$) Business Day following receipt of a written notice from owners of a failure under this Section 21.2.1(v); or

(vi) Any representation or warranty made by Contractor in Section 23.1 proves to be incorrect in any material respect when made and such breach of representation or warranty has a material adverse effect on Owners, unless Contractor promptly commences and diligently pursues action to cause such representation or warranty to become true in all material respects and does so within thirty (30) Days after written notice thereof has been given to Contractor by Owners (unless such cure is not capable of being effected within such thirty (30) Day period in which case Contractor shall have such longer period as is reasonably necessary to effect the cure but in no event longer than ninety (90) Days following Owners' notice and so long as Contractor has commenced the cure within such thirty (30) Day period and thereafter diligently pursues the cure) and such cure removes any material adverse effect on Owners of such representation or warranty having been incorrect.

21.2.2 Upon a Contractor Event of Default pursuant to this Section 21.2, in addition to any remedy available at Law, which is subject to the provisions of this Agreement limiting Contractor's liability, Owners may at their option elect to immediately terminate this Agreement by providing notice to Contractor. In the event of such termination:

(i) Contractor shall be liable to Owners and shall pay to Owners all costs and expenses incurred by Owners in transitioning the Work either to another contractor(s) and/or to Owners if Owners will perform any of the Work;

(ii) Contractor shall assist and cooperate in such transition as reasonably requested by Owners for a period of up to one hundred and eighty (180) Days, and the costs incurred by Contractor in providing such assistance and cooperation shall be treated as Non-Reimbursable Costs (such assistance and cooperation to include Contractor maintaining a number of field non-manual personnel at the Construction Site as necessary to support an orderly transition of the Work, taking such actions that are necessary or directed by the Owners for the protection and preservation of the Work, providing all records with respect to the Work performed, bearing all costs associated with Contractor's compliance with the WARN Act, and at Owners' direction actively supporting Owners' transition of the Work);

(iii) In the event: (i) such termination results in Owners permanently discontinuing the construction of the Facility; or (ii) such termination results from Contractor's Abandonment of the Work, then in either case of (i) or (ii), Contractor shall be liable to Owners and shall pay to Owners an amount equal to [***] of the Base Fee payments previously paid to Contractor by Owners prior to such termination;

(iv) Contractor shall be liable to Owners and shall pay to Owners an amount equal to [***] of the Earned Fee payments provisionally paid to Contractor by Owners, except to the extent that the Schedule Earned Fee for a Unit(s) and/or the Cost Earned Fee have previously been earned and determined to be due to Contractor pursuant to Section 8.7;

(v) Contractor shall be liable to Owners and shall pay to Owners all amounts then owed by Contractor to Owners under this Agreement but not paid pursuant to the terms of this Agreement;

(vi) Contractor shall be liable to Owners and shall pay to Owners all amounts paid by Owners for Reimbursable Costs pursuant to Monthly Funding Requests for Work which has not been performed as of the termination of this Agreement; and

(vii) Owners shall make payment to Contractor of all Reimbursable Costs for Work performed under this Agreement prior to termination of this Agreement and, subject to (iii) above, Owner shall make payment to Contractor of Base Fee payments related to the period prior to termination of this Agreement, which amounts may be offset by the amounts required to be paid by Contractor to Owners under subparts (i) through (v) above or any other provisions of this Agreement.

In the event of termination pursuant to this Section 21.2, Owners may, at their option, finish the Work by whatever method Owners may deem appropriate or expedient.

Owners shall use commercially reasonable efforts to mitigate costs required to be paid by Contractor under Section 21.2.2.

21.3 Termination by Owners for Convenience .

21.3.1 Owners may, at any time, terminate the Agreement for Owners' convenience and without cause and for any reason by providing at least ten (10) Days' notice to Contractor.

21.3.2 In the event of termination for Owners' convenience, Owners shall be liable for and shall pay to Contractor, to the extent not previously paid, the following:

(i) all Reimbursable Costs for the Work performed prior to the effective date of termination of this Agreement under Section 21.3.1;

(ii) all Base Fee payments related to the period prior to the effective date of termination of this Agreement;

(iii) costs of cancellation of Subcontracts and purchase orders to the extent that such Subcontracts and/or purchase orders are not assigned to and assumed by Owners;

(iv) costs incurred by Contractor during a period of no more than ninety (90) Days following the effective date of termination to bring Work on the Construction Site to an orderly conclusion including costs to demobilize Personnel and equipment, provided that such costs are substantiated by documentation reasonably satisfactory to Owners and subject to audit and verification pursuant to Section 36.4;

(v) costs incurred pursuant to the WARN Act, provided that Contractor provides prompt notice under the WARN Act after termination;

(vi) other costs incurred by Contractor and its Subcontractors in complying with Section 21.6; and

(vii) all amounts then owed by Owners to Contractor under this Agreement but not paid pursuant to the terms of this Agreement.

21.3.3 In the event of termination for Owners' convenience, Earned Fee payments received by Contractor prior to the effective date of termination will be deemed to have been earned by Contractor and will not be subject to repayment to Owners. Owners shall promptly return and release the Repayment Letter of Credit following notice of termination pursuant to Section 21.3.1.

21.3.4 In addition to the other payments to be made to Contractor pursuant to this Section 21.3:

21.3.4.1 if (i) the Cumulative Mechanical Completion Percentage for a Unit at the time of the notice of termination under this Section 21.3 (or, as applicable, the notice of termination under Section 21.1, 21.4 or 21.5) is [***] or greater; and (ii) the Project Schedule at such time indicates that Mechanical Completion of such Unit will be achieved on or before the Target Completion Date for such Unit, Owners shall be liable for and shall pay to Contractor the Schedule Earned Fee amounts expected to be earned by Contractor pursuant to Section 7.3 based on such projected Mechanical Completion date, to the extent such amounts have not been provisionally paid to Contractor (including any increased amount of Schedule Earned Fee expected to be earned pursuant to Section 7.3); and

21.3.4.2 if (i) the Cumulative Final Completion Percentage at the time of the notice of termination under this Section 21.3 (or, as applicable, the notice of termination under Section 21.1, 21.4 or 21.5) is [***] or greater; and (ii) the Project Cost Forecast at such time indicates that the Combined Construction Costs will be equal to or less than the Target Construction Cost, Owners shall be liable for and shall pay to Contractor the Cost Earned Fee amounts expected to be earned by Contractor pursuant to Section 7.4 based on such projected Combined Construction Costs, to the extent such amounts have not been provisionally paid to Contractor (including any increased amount of Cost Earned Fee expected to be earned pursuant to Section 7.4).

21.3.5 In the event of a termination for convenience under this Section 21.3, Contractor shall be liable to Owners and shall pay to Owners: (i) all amounts paid by Owners for Reimbursable Costs pursuant to Monthly Funding Requests for Work which has not been performed as of the termination of this Agreement; and (ii) all amounts then owed by Contractor to Owners under this Agreement but not paid pursuant to the terms of this Agreement.

21.3.6 In the event of a termination for convenience under this Section 21.3, Contractor shall use commercially reasonable efforts to mitigate Reimbursable Costs and other costs required to be paid by Owners under Section 21.3.2.

21.3.7 Upon such termination and after all payments required by this Section 21.3 have been paid, the Parties shall have no further liability to one another other than any liability that arose prior to the termination of this Agreement pursuant to this Section 21.3 or those which survive termination.

21.4 Termination Because of Extended Force Majeure Event.

21.4.1 Either Party may terminate this Agreement in the event that (i) a Force Majeure Event or a combination of Force Majeure Events is continuing to prevent the performance of the other Party under this Agreement for a consecutive period of more than one hundred eighty (180) Days; or (ii) a Force Majeure Event or a combination of Force Majeure Events is continuing to prevent the performance of the other Party under this Agreement and the period of the prevention of performance as a result of such Force Majeure Event(s), when combined with other period(s) of prevention resulting from other previous Force Majeure Event(s), exceeds a cumulative aggregate of two hundred seventy (270) Days.

21.4.2 In the event that a Party provides notice of termination under this Section 21.4, such termination shall be treated as a termination for convenience by Owners under Section 21.3; provided, however, that Section 21.3.4 shall not apply if Contractor is the Party that provides such notice of termination under this Section 21.4.

21.5 Owners Event of Default .

21.5.1 Contractor may declare an Owners Event of Default upon notice to Owners of the occurrence of any of the following (each an “Owners Event of Default”):

(i) Owners are in breach of a material provision of this Agreement (other than the matters addressed in the other subsections of this Section 21.5.1) and fail to cure the breach within thirty (30) Days following notice of such breach or, if such breach is not capable of being cured within such thirty (30) Day period, such longer period as is reasonably necessary but in no event longer than ninety (90) Days following written notice of such breach so long as Owners have commenced the cure within such thirty (30) Day period and thereafter diligently pursue the cure;

(ii) One or more of the Owners is Insolvent unless the other Owners have provided security for payments that would be due from such Insolvent Owner(s) that is reasonably acceptable to Contractor, and no other changes to this Agreement have resulted from proceedings involving the Insolvent Owner;

(iii) One or more Owners fail to comply with the requirements of Section 19.2 unless cured by the end of the seventh (7th) Business Day following receipt of a written notice from Contractor of a failure under this Section 21.5.1(iii), which cure may include one or more of the other Owners providing collateral security that satisfies the requirements of Section 19.2 on behalf of one or more Owners who fail to provide the required security.

(iv) Owners fail to make payment of any Undisputed Amount required to be made under this Agreement and Owners shall have failed to cure such failure within thirty (30) Days after notice from Contractor; for the avoidance of doubt, Contractor shall be entitled to declare an Owners Event of Default pursuant to this Section 21.5.1(iv) if any Owner fails to make payment of its portion of any such Undisputed Amount within such thirty (30) Day period and no other Owner(s) makes payment of such amount to Contractor on behalf of the non-paying Owner within such thirty (30) Day period, even if the other Owner(s) make payment of the amounts for which they are responsible; or

(v) Any representation or warranty made by Owners in Section 23.2 proves to be incorrect in any material respect when made and such breach of representation or warranty has a material adverse effect on Contractor, unless Owners promptly commence and diligently pursue action to cause such representation or warranty to become true in all material respects and does so within thirty (30) Days after written notice thereof has been given to Owners by Contractor (unless such cure is not capable of being effected within such thirty (30) Day period in which case Owners shall have such longer period as is reasonably necessary to effect the cure but in no event longer than ninety (90) Days following Contractor's notice and so long as Owners have commenced the cure within such thirty (30) Day period and thereafter diligently pursue the cure) and such cure removes any material adverse effect on Contractor of such representation or warranty having been incorrect.

21.5.2 Upon an Owners Event of Default, in addition to any remedy available at Law, which is subject to the provisions of this Agreement limiting Owners' liability, Contractor may at its option elect to immediately terminate this Agreement by providing notice to Owners. In the event that Contractor provides notice of termination under this Section 21.5, such termination shall be treated as a termination for convenience by Owners under Section 21.3. Upon such termination and after all payments required by Section 21.3 have been paid, the Parties shall have no further liability to one another other than any liability that arose prior to the termination of this Agreement pursuant to this Section 21.5 or which survive such termination as provided in this Agreement.

21.6 Further Obligations Upon Termination .

21.6.1 In the event that this Agreement is terminated under this Article 21, Contractor shall:

(i) in an orderly manner and consistent with safety considerations, cease the Work and leave the Construction Site as directed by Owners;

(ii) take such actions necessary, or that Owners may otherwise direct, for the protection and preservation of the Work (wherever located);

(iii) except for Work directed to be performed in connection with such termination as stated in the notice, enter into no further contracts, purchase orders or change orders;

(iv) remove all the Contractor-provided Construction Equipment, the waste and rubbish generated by Contractor's activities on Construction Site and the Hazardous Materials brought onto the Construction Site by Contractor;

(v) promptly assign to Owners or its designee any contract rights (including warranties, licenses, patents and copyrights) that it has to any or all the Work, including contracts with Subcontractors pursuant to Section 2.17 except with respect to Subcontracts with Affiliates of Contractor, and Contractor shall execute such documents as may be reasonably requested by Owner to evidence such assignment;

(vi) promptly provide to Owners all records of the Work performed by Contractor in connection with this Agreement and the Work; and

(vii) take such other actions as may be reasonably required hereunder in order for Owners or their designee to continue and transition the performance of the Work upon termination of this Agreement.

21.6.2 All amounts required to be paid by a Party under Sections 21.2, 21.3, 21.4 and 21.5 (as applicable) shall be paid by the Party required to pay such amounts within thirty (30) Days after receipt of an invoice(s) from the other Party.

21.6.3 Notwithstanding the termination of this Agreement under this Article 21 and the payment of amounts required to be paid under this Article 21, upon any such termination, neither Party shall be relieved of, and no part of the payments required to be paid under this Article 21 shall constitute compensation for the following (and all of which obligations shall survive the termination of this Agreement):

(i) liabilities and obligations of each Party resulting, arising or accruing prior to such termination;

(ii) each Party's indemnification obligations under this Agreement (including under Article 16); or

(iii) any loss or damages to the extent insurance proceeds are received from the insurance required under this Agreement (it being the Parties specific intent that insurers' obligations shall not be relieved for insured risks).

## ARTICLE 22

## PROTECTED INFORMATION

22.1 Definition of Protected Information. "Protected Information" means the terms of this Agreement and any and all information, data, software, matter or thing of a secret, confidential or private nature identified as "confidential", "proprietary" or the like by the Party which claims the information to be proprietary, relating to the business of the disclosing Party or its Affiliates, including matters of a technical nature (such as know-how, processes, data and techniques), matters of a business nature (such as information about schedules, costs, profits, markets, sales, customers, suppliers, the Parties' contractual dealings with each other and the projects that are the subject-matter thereof), matters of a proprietary nature (such as information about patents, patent applications, copyrights, trade secrets and trademarks), other information of a similar nature, and any other information which has been derived from the foregoing information by the receiving Party; provided, however, that Protected Information shall not include information which: (a) is legally in possession of a receiving Party prior to receipt thereof from the other Party; (b) a receiving Party can show by reasonable evidence to have been independently developed by the receiving Party or its employees, consultants, Affiliates or agents; (c) enters the public domain through no fault of a receiving Party or others within its control; or (d) is disclosed to a receiving Party by a third party, without restriction or breach of an obligation of confidentiality to the disclosing Party.

22.2 Use and Protection of Protected Information .

22.2.1 Each party acknowledges that, during the term of the Agreement, it may have access to Protected Information of the other Party and its Affiliates, including Protected Information of a third party, which Protected Information represents a substantial investment. Unless the disclosing Party agrees otherwise in advance and in writing, and subject to the requirements specified in Section 22.3 below, the receiving Party agrees that it will limit access to such Protected Information to its Personnel, Affiliates, and members and their respective subcontractors and other representatives and bulk power purchasers, who require the information in connection with activities under this Agreement; provided that such Personnel, Affiliates, subcontractors and other representatives and bulk power purchasers shall be required to keep Protected Information confidential.

22.2.2 Each Party agrees that any Protected Information that is disclosed to it or its Personnel, Affiliates, and members and their respective subcontractors and other representatives and bulk power purchasers will be used solely for the purpose of performing its obligations and exercising its rights under this Agreement or otherwise in connection with the Facility, including for purposes of construction, testing, completion and defense of ITAACs, startup, trouble-shooting, response to plant events, inspection, evaluation of system or component performance, scheduling, investigations, operation, maintenance, training, repair, licensing, modification, decommissioning and compliance with Laws or the requirements of governmental authorities ("Permitted Purpose"). Each Party agrees that any Protected Information that is disclosed to it will be used solely for the purpose such information is intended.

22.2.3 Each receiving Party agrees to exercise efforts consistent with the efforts that its exercises to protect information of its own that it regards as confidential, but no less than reasonable efforts, to keep such Protected Information in confidence and not to copy (except in connection with the Permitted Purpose) or permit others to copy or access the information or disclose, redistribute, or publish the same to unauthorized persons, or use or modify for use, directly or indirectly in any way for anyone any item of such Protected Information at any time during the term of the Agreement or after its expiration for any purpose other than the Permitted Purpose.

22.2.4 To the extent required to ensure compliance with applicable Laws, each receiving Party agrees that disclosing Party's Protected Information will exclusively be stored, processed accessed and/or viewed in or from United States data centers and receiving Party will not export any such Protected Information nor allow access by any foreign national contrary to the Laws of the United States or otherwise perform any such processing or access outside of the United States without prior written approval from the disclosing Party.

22.2.5 Each receiving Party acknowledges and agrees that any disclosure or use of the disclosing Party's Protected Information, except as otherwise authorized herein or by disclosing Party in writing, would be wrongful and cause immediate and irreparable injury to disclosing Party or to any third party owner whose Protected Information is under disclosing Party's care and custody and agrees to cooperate with disclosing Party in obtaining an injunction if necessary to prevent further disclosure thereof.

22.2.6 In the event that receiving Party is mandated by applicable Law, including any subpoena or other similar form of process, to disclose any of disclosing Party's Protected Information, receiving Party, to the extent legally permissible, must provide disclosing Party with written notice before making any such disclosure so as to afford disclosing Party with an adequate opportunity either (i) to seek a protective order or other appropriate relief and/or (ii) to waive the requirement that receiving Party not disclose the Protected Information. In the event that any disclosure is required, receiving Party may disclose such information but must furnish only that portion of the Protected Information that is legally required and must exercise its reasonable efforts to obtain a reliable assurance that confidential treatment will be accorded the Protected Information that is disclosed. Contractor agrees that Owners may disclose, without further approval, this Agreement and any amendments hereto in any filing made with the Securities Exchange Commission, Department of Energy, and Georgia Public Service Commission for purposes of satisfying Owners' regulatory disclosure obligations. Prior to any such disclosure, Owners shall give written notice to Contractor. In connection with any such filing of this Agreement and any amendments hereto, Owners will seek to obtain confidential treatment with respect to such portions of the Agreement as the Owners shall reasonably determine may be permitted by law, after consultation in good faith with Contractor.

22.2.7 Disclosing Party is not obligated under this Article to reveal proprietary information to receiving Party. Receiving Party shall indemnify and hold the Owners' Interests or Contractors' Interests, as the case may be, harmless from any and all Third Party Claims, actions, suits, judgments, and expenses (including attorney's fees) resulting from receiving Party's breach of its obligations in this Article concerning the proprietary information of the disclosing Party.

22.2.8 Each receiving Party agrees to cooperate with disclosing Party's reasonable confidentiality requirements that may be established from time to time, including the signing of a separate confidentiality or non-disclosure agreement, and immediately notify disclosing Party of any unauthorized disclosure or use or any such Protected Information of which receiving Party becomes aware.

22.3 Westinghouse Protected Information .

22.3.1 Contractor acknowledges that Owners will provide Contractor with certain AP1000 design information and other Protected Information that is owned by Westinghouse or its affiliates and that Owners are obligated to maintain the confidentiality of such Protected Information in connection with Contractor's use thereof ("Westinghouse Protected Information"). Notwithstanding anything to the contrary herein, Contractor shall not disclose Westinghouse Protected Information received from Owners to any Third Party, including its subcontractors, consultants, or other agents, until such recipient has executed a confidentiality agreement substantially in the form attached hereto as Exhibit S; provided, however, that any recipient that previously executed a confidentiality agreement or acknowledgement in a form attached to the Engineering Procurement and Construction Agreement between Westinghouse and Owners, dated April 8, 2008, shall not be required to execute a new confidentiality agreement in the form of Exhibit S, it being agreed by the Parties that the confidentiality agreement signed by such recipient, while it remains in effect, shall satisfy the requirements of this Article 22. Contractor may only disclose Westinghouse Protected Information to an Affiliate if such Affiliate is subject to a confidentiality obligation consistent with the protections provided in Exhibit S. Prior to disclosing Westinghouse Protected Information to any Third Party or any Affiliate other than the Affiliate Subcontractors listed herein, Contractor shall obtain Owners' approval and shall cooperate with any efforts undertaken by Owners to determine whether Westinghouse approval is required for such disclosure and, if necessary, to obtain Westinghouse's approval. Should either Party discover a breach of the terms and conditions of any such confidentiality agreement by counterparty thereto, such Party will promptly notify the other Party of such breach and provide to such other Party necessary information and support pertaining to any suit or proceeding contemplated or brought by the original disclosing Party against such counterparty for such breach.

22.3.2 Nothing herein grants the right to a receiving Party (or implies a license under any patent) to sell, license, lease, or cause to have sold any Protected Information supplied by the disclosing Party under this Agreement. Neither Party shall, at any time file, cause or authorize the filing of any patent application in any country in respect of any invention derived from the Protected Information supplied hereunder. As between Owners and Contractor, title to Protected Information provided by one Party to the other Party and all copies made by or for the receiving Party in whole or in part from such Protected Information remains with the disclosing Party.

22.3.3 Except where necessary in connection with the Permitted Purpose, the receiving Party shall not make any copy or in any way reproduce or excerpt Protected Information. Any such copies or excerpts shall include all confidential or proprietary notices and designations. Upon the written request of the disclosing Party, the Protected Information provided hereunder and any such copies or excerpts thereof shall be returned to the disclosing Party, or, at the sole option and request of the disclosing Party, the receiving Party shall destroy such information and any such copies and/or excerpts and certify in writing to the disclosing Party that such information has in fact been destroyed.

22.3.4 Disclosing Party shall not be responsible to receiving Party for the consequence of the use of Protected Information by receiving Party for any purpose other than the Permitted Purpose.

22.3.5 Disclosing Party must not arbitrarily mark documents as proprietary or confidential and will limit such designations to what disclosing Party believes has a sufficient factual and/or legal basis to be genuinely protectable proprietary information. Receiving Party's acceptance of transmittal of documents marked as disclosing Party's Protected Information will not constitute any acquiescence or admission by receiving Party that such documents are indeed genuinely protectable proprietary information so long as receiving Party timely raise any objections to disclosing Party's marking of information as Protected Information.

22.3.7 Receiving Party acknowledges and agrees that disclosing Party shall not be liable to any third party to whom receiving Party provides any Protected Information based on its use or reliance on such deliverables, such liability, if any, being assumed by receiving Party and addressed in receiving Party's contracts with such third party.

22.4 <u>Export Control</u> .

22.4.1 Each Party agrees not to disclose, directly or indirectly transfer, export, or re-export any Protected Information, or any direct or indirect products or technical data resulting therefrom to any country, natural person or entity, except in accordance with applicable export control Law.

22.4.2 To assure compliance with the export control Laws and regulations of the United States government, specifically the U. S. Department of Energy export regulations of nuclear technology under 10 C.F.R. Part 810, the U.S. Nuclear Regulatory Commission export and import regulations related to nuclear equipment and material under 10 C.F.R. Part 110, and the U.S. Department of Commerce export regulations of commercial or dual-use technology under 15 C.F.R. Part 730 et seq. concerning the export of technical data or similar information to specific countries, locations, or entities, a Party shall not disclose or permit the disclosure, transfer or re-export, directly or indirectly, of any Protected Information it receives hereunder that a receiving Party considers to be potentially subject to U.S. export control, or any product or technical data derived from such Protected Information, except in compliance with such export control Laws, which may be contingent on additional United States Governmental Approvals.

22.4.3 Each Party shall cooperate in good faith with the reasonable requests of the other Party made for purposes of either Party's compliance with such Laws and regulations. Contractor acknowledges that Protected Information which is subject to U.S. export control is contained within databases and/or servers located at the Site. Contractor shall ensure that all Contractor personnel granted access to the Site shall (a) not be included in any published lists maintained by the U.S. government of persons and entities whose export or import privileges have been denied or restricted and (b) either be a U.S. Person (defined as a U.S. citizen, lawful permanent resident, or protected individual under the Immigration and Naturalization Act of 8 U.S.C. § 1324b(a)(3)), person from a "generally authorized" country, the recipient of a "deemed export" authorization, or a person acting under continuance activities per the savings clause provision of 10 C.F.R. § 810.16(b), and Contractor shall be required to maintain with Owner or obtain such authorizations as needed and comply with any and all corresponding reporting obligations. Nothing in this Section 22.4.3 shall limit Owners' right to deny access to the Site to any Contractor personnel where Owners determine that granting access would not comply with applicable Law.

22.4.4 Notwithstanding any other provisions in this Agreement, the obligations set forth in this Section 22.4 shall be binding on the Parties so long as the relevant United States export control Laws and regulations are in effect.

## ARTICLE 23

## REPRESENTATIONS AND WARRANTIES

23.1 Representations and Warranties of Contractor. Contractor hereby represents and warrants to Owners as of the Effective Date as follows:

(i) Due Organization Contractor. Contractor is duly organized, validly existing and in good standing under the Laws of the State of Nevada. Contractor has the requisite power and authority to own and operate its business and properties and to carry on its business as such business is now being conducted and is duly qualified to do business in the State of Georgia and in any other jurisdiction in which the transaction of its business makes such qualification necessary.

(ii) Due Authorization; Binding Obligation. Contractor has full power and authority to execute and deliver this Agreement and to perform its obligations hereunder, and the execution, delivery and performance of this Agreement by Contractor has been duly authorized by the necessary action on the part of Contractor; this Agreement has been duly executed and delivered by Contractor and is the valid and binding obligation of Contractor enforceable in accordance with its terms except as limited by applicable bankruptcy, insolvency, reorganization, moratorium or other Laws affecting the rights of creditors generally and by general principles of equity.

(iii) Non-Contravention. The execution, delivery and performance of this Agreement by Contractor and the consummation of the transactions contemplated hereby do not and will not contravene the organizational documents of Contractor and do not and will not conflict with or result in a breach of or default under any indenture, mortgage, lease, agreement, instrument, judgment, decree, order or ruling to which Contractor is a party or by which it or any of its properties is bound or affected.

(iv) Approvals. There are no approvals or consents of Governmental Authorities or other Persons not yet obtained, the absence of which would materially impair Contractor's ability to execute, deliver and perform its obligations under this Agreement.

23.2 Representations and Warranties of Owners. Each Owner hereby represents, warrants and covenants to Contractor as of the Effective Date as follows (it being acknowledged that, in light of the provisions of Sections 18.3.1 and 18.3.2 with respect to Dalton Utilities, the representations, warranties and covenants of Dalton Utilities pertain only to that separate and distinct part of the City of Dalton that constitutes Dalton Utilities):

(i) Due Organization of Owner. Owner is duly organized, validly existing and in good standing under the Laws of the State of Georgia and has the requisite power and authority to own and operate its business and properties and to carry on its business as such business is now being conducted and is duly qualified to do business in State of Georgia and in any other jurisdiction in which the transaction of its business makes such qualification necessary.

(ii) Due Authorization of Owner; Binding Obligation. The execution, delivery and performance of this Agreement by Owner have been duly and effectively authorized by the requisite action on the part of such Owner's governing board. This Agreement constitutes the legal, valid and binding obligations of such Owner, enforceable against such Owner in accordance with its terms, except as limited by applicable bankruptcy, insolvency, reorganization, moratorium or other Laws affecting the rights of creditors generally and by general principles of equity.

(iii) Non-Contravention. The execution, delivery and performance of this Agreement by Owner and the consummation of the transactions contemplated hereby do not and will not contravene the organizational documents of such Owner and do not and will not conflict with or result in a breach of or default under any indenture, mortgage, lease, agreement, instrument, judgment, decree, order or ruling to which such Owner is a party or by which it or any of its properties is bound or affected.

(iv) Approvals. There are no approvals or consents of Governmental Authorities or other Persons not yet obtained, the absence of which would materially impair such Owner's ability to execute, deliver and perform its obligations under this Agreement. Contractor acknowledges and agrees that, as of the Effective Date, Owners have not obtained approval of the Georgia PSC or other required approval to continue with the construction of the Facility, and although the failure to obtain such approval would not impair Owner's ability to execute, deliver or perform its obligations under this Agreement, such failure would impact Owners' decision of whether to continue with the construction of the Facility.

(v) VEGP Units 1 and 2 . The Owners are the owners of VEGP Units 1 and 2.

23.3 Representations and Warranties of GPC . GPC hereby represents, warrants and covenants to Contractor that it has all full power and authority to execute and deliver this Agreement on behalf of itself and the other Owners and that all actions taken and decisions made by GPC (or by Southern Nuclear on GPC's behalf) under and in connection with this Agreement are binding on itself and the other Owners.

## ARTICLE 24

## TITLE; RISK OF LOSS

24.1 Transfer of Title; Intellectual Property .

24.1.1 Except as otherwise expressly provided in this Agreement, title to any materials and supplies used in connection with the Work and which become a part of the Facility or which are otherwise provided to Owners shall vest in Owners upon Owners' payment therefore.

24.1.2 Subject to the license granted herein, Contractor shall retain ownership of all intellectual property rights in any items provided by Contractor or its Subcontractors for use in performing the Work and in any discoveries and inventions (patentable or unpatentable) and copyrightable material that Contractor or any of its Subcontractors makes, creates, develops, discovers or produces in connection with the performance of the Work; provided, however, that Contractor hereby grants to Owners and their Affiliates a royalty-free, fully paid up, irrevocable, worldwide, fully sublicensable, nonexclusive license to use the deliverables required to be delivered by Contractor as part of the Work in connection with the operation, modification and maintenance of the Facility. Notwithstanding the foregoing, nothing in this Section 24.1.2 is intended to provide or transfer to Contractor ownership of any intellectual property rights in any Issued for Construction Documents, Specifications, or any of Westinghouse's, Owners', or their Affiliates' intellectual property or proprietary information (including revisions or derivative works thereto, even where such revisions or derivative works may be the product of or include Contractor's Work).

24.1.3 Both Parties shall ensure that the other Party and its subcontractors are, to the extent required in connection with the Work or the Project, granted appropriate rights to use documents previously prepared or used by third parties, including Westinghouse Electric Company LLC and its Affiliates and the subcontractors of the foregoing in the construction of the Facility.

24.2 Risk of Loss. Contractor shall be responsible for the care, custody, and control of, and shall bear the complete risk of loss, destruction, or damage of, the materials, supplies, Construction Materials, Construction Equipment and other equipment, machines and structures that will not become a permanent part of the Facility and which in each case are provided by Contractor, its Subcontractors, or the Personnel or Invitees of any of them to perform the Work.

## ARTICLE 25

## APPLICABLE LAWS AND REGULATIONS

25.1 Compliance with Applicable Laws. Contractor represents that in performing the obligations of this Agreement, all applicable Laws have been and will be complied with by Contractor and its Personnel and Subcontractors.

25.2 Specific Applicable Law Requirements. Contractor will adhere to applicable Laws including for example: (i) all labor laws and regulations including the use of U.S. citizens or properly documented alien workers under the Immigration Act of 1990 and the Immigration and Nationality Act of 1952, as amended; (ii) all applicable safety and health standards required by the Nuclear Regulatory Commission as well as all applicable safety and health standards promulgated under the Occupational Safety and Health Act of 1970, as amended, including but not limited to OSHA General Industry Regulations 1910.269 and 1926 Subpart V and all applicable state or local health or safety authority with jurisdiction over the work or services performed or to be performed under this Contract; (iii) the Department of Homeland Security's E-Verify requirements as well as applicable State immigration laws; (iv) the Foreign Corrupt Practices Act, 15 U.S.C. §§ 78dd-1, *et seq*. (as that Act may be amended from time to time); (v) the requirements and prohibitions of 10 C.F.R. Part 810, as well as all applicable laws and regulations identified in this Agreement.

25.3 Conflict Minerals. In accordance with the provisions of § 1502 of the Dodd-Frank Wall Street Reform and Consumer Protection Act involving disclosures relating to "Conflict Minerals" originating in the Democratic Republic of the Congo or an adjoining country, Contractor represents that it has not recommended or included in any drawings, designs or specifications any products or materials which contain any "Conflict Minerals" which originate from the Democratic Republic of the Congo or neighboring countries.

25.4 OFAC. Contractor hereby represents and warrants as follows at all times during the term of this Contract: (i) neither it, nor any of its employees, authorized agents, subcontractors, principals or beneficial owners, is a Specially Designated National ("SDN") as defined by U.S. Department of the Treasury Office of Foreign Asset Control ("OFAC"); (ii) neither it, nor any of its employees, authorized agents, subcontractors, principals or beneficial owners, is a citizen of a country subject to an OFAC Country Sanction; (iii) it, and all of its employees, authorized agents, subcontractors, principals or beneficial owners, are in compliance with any and all applicable Laws and regulations relating to the prevention of money laundering and the financing of terrorism to which they are expressly subject.

25.5 Government Submittals. When applicable and appropriate, Contractor will promptly furnish Owners with a copy of all evaluations or notifications concerning the Work submitted to Governmental authorities (including the NRC) by Contractor or its Subcontractors.

25.6 Federal Acquisition Regulations. Certain Owners are government contractors under an Area Wide Public Utilities Contract with the General Services Administration of the United States Government or pursuant to one or more other agreements. Contractor agrees that each of the Clauses contained in the Federal Acquisition Regulations referred to below, shall, as if set forth herein in full text, be incorporated into and form a part of the Agreement, and Contractor shall comply therewith, if and to the extent applicable:

| | | |
|---|---|---|
| (1) | 52.203-3 | Gratuities (APR 1984); |
| (2) | 52.203-6 | Restrictions on Subcontractor Sales to the Government (SEP 2006); |
| (3) | 52.203-7 | Anti-Kickback Procedures (MAY 2014); |
| (4) | 52.219-8 | Utilization of Small Business Concerns (OCT 2014); |
| (5) | 52.219-9 | Small Business Subcontracting Plan (OCT 2014); |
| (6) | 52.222-21 | Prohibition of Segregated Facilities (FEB 1999); |
| (7) | 52.222-26 | Equal Opportunity (MAR 2007); |
| (8) | 52.222-37 | Employment Reports on Veterans (JUL 2014) |
| (9) | 52.222-40 | Notification of Employee Rights under the National Labor Relations Act (DEC 2010) |
| (10) | 52.222-50 | Combating Trafficking in Persons (FEB 2009) |
| (11) | 52.222-54 | Employment Eligibility Verification (AUG 2013) |
| (12) | 52.225-13 | Restrictions on Certain Foreign Purchases (JUN 2008) |

Upon written request, Owner will provide the full text of any of the above clauses incorporated herein by reference.

25.7 Subcontracting Plan. If Contractor is subject to the requirements set forth in Federal Acquisition Regulations 52.219-9, Contractor will (i) adopt a subcontracting plan ("Plan") that complies with the requirements of 52.219-9; (ii) provide a written copy of the Plan to Owners, and (iii) upon written request, provide timely periodic reports to the Owners that reflect the amounts paid to subcontractors who are a small business concern, veteran owned small business concern, service-disabled veteran-owned small business concern, HUBZone small business concern, small disadvantaged business concern, or women-owned small business concern.

25.8 Debarment. Debarment and Suspension (see 31 U.S.C. § 6101, Executive Orders 12549 and 12689, 7 C.F.R. 1726.16) - the federal law which prohibits Owner from knowingly purchasing goods or services from persons who are debarred, suspended, proposed for debarment, declared ineligible or voluntarily excluded from participating in transactions with the Federal Government or transactions with participants in programs funded in whole or in part by Federal grants, loans or loan guarantees. Contractor certifies at all times while Contractor is performing services under this Contract that neither it nor its principals is debarred, suspended, proposed for debarment, declared ineligible, or voluntarily excluded from participation in this transaction by any federal department or agency of the government of the United States of America. Contractor shall provide immediate written notice to Owner if Contractor learns that its certification was erroneous when submitted or has become erroneous by reason of changed circumstances. Contractor agrees it shall not knowingly enter into any lower tier covered transaction with a person who is proposed for debarment, debarred, suspended, declared ineligible, or voluntarily excluded from participation in this covered transaction, unless authorized by the department or agency with which this transaction originated, and shall obtain a certification that the counterparty if any lower tier covered transaction for services under this Contract is not debarred, suspended, proposed for debarment, declared ineligible, or voluntarily excluded from participation in this transaction by any federal department or agency of the government of the United States of America.

25.9 BAA. Buy-American (see 7 U.S.C. § 903, 7 C.F.R. 1726.15) - the federal law which requires the use of only such unmanufactured materials as have been mined or produced in the United States of America or any "eligible" (as defined in the statute) country and only such manufactured materials as have been manufactured in the United States or any eligible country substantially all (50% or more) from items mined, produced or manufactured in the United States or America or any eligible country, subject to certain exemptions. Contractor shall provide to Owner such information, documents, and certificates as may be requested by Owner or the Administrator of the Rural Utilities Service from time to time with respect to any articles, materials or supplies provided by Contractor in connection with this Contract.

25.10 Lobbying. Lobbying (see 7 C.F.R. 418) - the federal law which prohibits funds appropriated by the government of the United States of America from being used to pay any person for influencing or attempting to influence certain federal officers or agents in connection with the making of a federal loan. Contractor has delivered a signed certification in the form shown attached and incorporated herein as Exhibit T. Contractor has read and understood Exhibit T, will sign and deliver additional counterparts of such certification whenever requested by Owner, and will perform all of the requirements set forth in the certification.

25.11 Davis-Bacon Act Required Contract Clauses.

(i) The contract clauses contained under the heading "Davis-Bacon Act Required Provisions" in Exhibit J (Davis-Bacon Act Required Provisions) to this Agreement shall, as if set forth herein in full text, be incorporated into and form a part of this Agreement, and Contractor shall comply therewith where applicable.

(a) The Parties will cooperate in seeking appropriate exemptions from disclosure under the Freedom of Information Act, 5 U.S.C. § 552, and associated regulations for certified payroll data provided to federal agencies in the course of compliance with the Davis-Bacon Act and the Davis-Bacon Act regulations.

(b) Where necessary and required by law, Contractor will support Owners with the maintenance of the DAVIS-BACON AND RELATED ACTS COMPLIANCE PROGRAM FOR VOGTLE UNITS 3&4 PROJECT.

(ii) The wage determinations set forth in Exhibit J are applicable to Work provided under this Agreement.

## ARTICLE 26

## EQUAL EMPLOYMENT OPPORTUNITY

26.1 Owners' Equal Employment Opportunity Compliance. Owners comply with all applicable federal and state fair employment laws, including, without limitation, Title VII of the Civil Rights Act of 1964, the Age Discrimination in Employment Act of 1967, the Americans with Disabilities Act of 1990, all provisions of Executive Order 11246 as amended, 41 C.F.R. § 60-1, and all of the rules, regulations and relevant orders of the Secretary of Labor. Owners prohibit any acts of discrimination, or harassment including offensive words or conduct, on the basis of race, color, religion, age, disability, veteran status, gender, sex, sexual orientation, gender identity, national origin or any other basis prohibited by law. Owners' work environment must remain free from distractions caused by negative words or actions. Owners are committed to taking affirmative action as required by law and to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, gender, color, religion, age, national origin, disability, veteran status, or any classification protected by federal, state or local law. Such action includes but is not limited to, the following: employment, upgrading, demotion or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. Owners post in conspicuous places, available to employees and applicants for employment, notices to which state that all qualified applicants will receive consideration for employment without regard to race, gender, color, religion, age, national origin, sexual orientation, physical handicap, or veteran status.

26.2 Contractor's Equal Employment Opportunity Compliance. Contractor will comply with all applicable federal and state fair employment laws, including, without limitation, Title VII of the Civil Rights Act of 1964, the Age Discrimination in Employment Act of 1967 and the Americans with Disabilities Act of 1990, and all provisions of Executive Order 11246 as amended, 41 C.F.R. § 60-1, and all of the rules, regulations and relevant orders of the Secretary of Labor. Contractor will not discriminate against any employee or applicant for employment because of race, color, religion, age, disability, veteran status, genetic information, gender, sex, sexual orientation, gender identity, national origin, or any classification protected by federal, state or local law. Contractor shall take affirmative action as required by law and to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, gender, color, religion, age, national origin, disability, veteran status, or any classification protected by federal, state or local law. Such action will include, but not be limited to, the following: employment, upgrading, demotion or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. Contractor agrees to post in conspicuous places, available to employees and applicants for employment, notices which state that all qualified applicants will receive consideration for employment without regard to race, gender, color, religion, age, national origin, disability, or veteran status.

26.3 VEVRAA. In accordance with the U.S. Department of Labor's regulations implementing the Vietnam Era Veterans Readjustment Assistance Act (VEVRAA, as amended) at 41 C.F.R. Part 60-300, Owners and Contractor shall abide by the requirements of 41 C.F.R. § 60-300.5(a). **This regulation prohibits discrimination against qualified protected veterans, and requires affirmative action by covered prime contractors and subcontractors to employ and advance in employment qualified protected veterans.**

26.4 Rehabilitation Act. In accordance with the U.S. Department of Labor's regulations implementing Section 503 of the Rehabilitation Act of 1973, as amended (Section 503) at 41 C.F.R. Part 60-741, Owners and Contractor shall abide by the requirements of 41 C.F.R. § 60-741.5(a). **This regulation prohibits discrimination against qualified individuals on the basis of disability, and requires affirmative action by covered prime contractors and subcontractors to employ and advance in employment qualified individuals with disabilities.**

## ARTICLE 27

## CYBER SECURITY PROGRAM REQUIREMENTS

27.1 Protection of Digital Computer and Communication Systems and Networks. Contractor understands that Owners are required under 10 C.F.R. § 73.54 to assure all Work performed related to digital computer and communication systems and networks are adequately protected against cyber-attacks, including the design basis threat described in 10 U.S.C. § 73.1, or Work associated with (i) safety-related and important-to-safety functions, (ii) security functions, (iii) emergency preparedness functions, (iv) and support systems and equipment which if compromised, would adversely impact safety, security, or emergency preparedness functions. Contractor agrees that all related Work performed by Contractor will be performed in compliance with Owners' cyber security plan. As part of Contractors obligations under this provision, Contractor agrees to the following:

(i) Right of Access. Owners, its agents or assignees, shall have the right to evaluate applicable areas of Contractor or sub-tier provider facilities and activities at a mutually agreed time during the procurement process to ensure compliance with agreed cyber security protocols. Such evaluation performed by Owners or its agents shall in no way relieve Contractor or its sub-tiers of any responsibilities under this Agreement.

(ii) Control of Sub-tier Subcontracting. Subject to Article 5, Contractor shall be responsible for assuring that all Subcontractors are working to Contractor's Quality Assurance Program or to the Subcontractors' own quality assurance program that has been approved by Contractor. Contractor shall provide appropriate verification of quality for all Subcontractors.

(iii) Records Retention. Contractor will retain records pertaining to the Work consistent with Contractor's corporate record retention policies.

27.2 Contractor Worker Network Access Compliance.

27.2.1 Owners are committed to maintaining a drug-free and alcohol-free workplace and requires that anyone having access to Owners' electronic systems and network and/or performing services that directly impact Owners' personnel, systems, networks, facilities, equipment, or operations: (i) is free from the effects of drugs or alcohol that may impair work performance; and (ii) meets trustworthiness and behavioral standards. Contractor must maintain and enforce a drug-free and alcohol-free workplace policy which is applicable to those of its employees working under this Agreement throughout this Agreement's term. These requirements apply to Contractor and all its representatives, including its Subcontractors of any tier, which have access to Owners' electronic systems and network. Contractor will require that all of its representatives who have access to Owners' electronic systems and network will abide by Contractor's Code of Conduct and Business Ethics and will have the legal right to work in the United States.

27.2.2 All Contractor and Subcontractor Personnel representatives who will have access to Owners' electronic systems and network will be subject to a background investigation, at Owners' expense, conducted by Employment Screening Services ("ESS" or "Provider"), or other vendor identified by Owners to provide background screenings for contract workers (provided that, in each case, Contractor is reasonably satisfied that such Provider or such other company will maintain the confidentiality of such information). Contractor will obtain from Owners a Southern Company Consent form entitled Consent to Release Information for Background Investigation. Contractor will complete the form and contact the Provider at 1-866-859-0143 and request a Southern Company background investigation for each such Contractor representative. Any of Contractor's representatives who do not meet the investigation requirements will not be granted system access, will be dismissed from the Construction Site, and will be barred from other Owners' sites. In the future, an on-line request option will become available, and either Employment Screening Services or Owners will notify Contractor of the availability of the on-line request option and provide the link to the website, which Contractor may then use in lieu of the telephone option above.

27.2.3 Before each background investigation is conducted, each Contractor representative who will have access to Owners' electronic systems and network must sign a consent form authorizing the background check (to the extent consistent with applicable federal, state or and local laws) and releasing all background investigation results to his/her employer and, if necessary, to Owners. Failure to provide such consent will result in the individual not having access Owners' electronic systems and network. Based on the investigation results, Provider will judge the background investigation results and notify Owners as to whether each of the screened employees is "Compliant" or "Non-Compliant." An individual is "Non-Compliant" and disqualified if the background investigation reveals any of the following:

- Felony conviction;
- Conviction for certain misdemeanors;
- DUI/DWI convictions (two in past five years);
- Pending charges that, if resulting in a conviction, would disqualify for one of the preceding reasons;
- Currently on probation for charges related to one of the preceding reasons;
- Pattern of behavior in the past that may not have resulted in a conviction, but that indicates involvement in criminal activity;
- Incident of workplace violence;
- Willful omission, misrepresentation, or falsification of personal data provided for background investigation purposes;
- Not authorized to work in the United States;
- Currently prohibited from performing work for, or for any contractor on behalf of, any affiliate of SNC; or
- Suspended or revoked driver's license (for any position that requires driving).

27.2.4 Owners may conduct audits during this Agreement's term to verify compliance with this Section. Neither reservation, nor exercise, of these rights relieves Contractor from compliance nor constitutes exercise of control over manner or means of implementing this Section. No act or omission of SNC waives SNC's right to enforce, or Contractor's duty to comply with, the requirements of this Article. SNC also may change the foregoing network access requirements at any time, with the revisions becoming effective upon notice to Contractor; provided that Contractor is given a reasonable opportunity to comply with and implement any such changes. In addition to this Agreement's general indemnity provisions, Contractor must indemnify Owners' Interests against a Third Party Claim arising out of or resulting from Contractor's non-compliance with this Article. This indemnity obligation will survive Agreement termination, cancellation, expiration, or completion.

27.2.5 A Background Investigation Toolkit is available upon request from Southern Nuclear. Contractor may contact the Provider of the Background Investigation at the following website: www.es2.com.

27.3 Procurement of Services . If and to the extent that Contractor provides cyber security related Work or any Work on critical digital assets (hardware, firmware, operating systems, or application software) at Owners' facilities, such Work will be subject to the controls of SNC's Quality Assurance Program, and Contractor agrees to abide by SNC's Quality Assurance Program, including as follows (provided that in the event of a conflict, SNC's Quality Assurance Program requirements will control):

(i) Contractor, before beginning permitted access to SNC's network, will be made aware of SNC's Quality Assurance Program and must agree to abide by the relevant policies; and Contractor will at all times remain responsible for the compliance of its authorized Personnel and sub-tier contractors.

(ii) Contractor will participate in SNC's cyber security training programs or equivalent qualification from Contractor, subject to SNC's approval of such qualification.

(iii) Contractor will require:

(a) Configuration management of the Contractor's computers, hardware or other equipment to include virus protection, patch management, authentication requirements and secure internet connections.

(b) The maintenance and secure transfer and storage of information and code while off-site to include appropriate encryption, security and deletion protocols.

(c) A duty to protect confidentiality.

(d) Software quality assurance ("SQA") procedures.

(e) Approved and disapproved software requirements tabulation.

(f) Processes and procedures for background investigations.

(g) SNC's right to audit or access to Contractor's cyber security program and quality assurance program. Contractor shall have no responsibility to update any deliverables or work products delivered as part of any cyber security services in light of future events or circumstances, unless Contractor specifically agrees to do so. Contractor shall be entitled to state in its deliverables and work products disclaimers and liability limitations consistent with the foregoing.

27.4 Construction. This Section contains numerous references to statutes, regulations, SNC and Contractor programs, policies and procedures ("Source Documents"); in each instance, such references and all definitions used in this Section derived from the Source Documents are intended to (and shall be deemed to) include all future revisions, amendments and modifications implemented from time to time to the Source Documents and the definitions derived from the Source Documents. Furthermore, to the extent any statute, regulation, SNC or Contractor program, policy or procedure is enacted in the future and reasonably would be expected to relate to the subject matter hereof, the parties shall negotiate in good faith to revise this Section to address such items as deemed reasonably appropriate by the parties.

## ARTICLE 28

## SITE AND SECURITY RULES AND POLICIES

28.1 Site Rules. Contractor represents and warrants that it will ensure that its Personnel shall comply with, all applicable rules, regulations, policies, programs, procedures and other requirements of the Owners or Southern Nuclear, including, but not limited to, the subparts below as well as those applicable requirements relating to site, security, fitness for duty quality concerns, quality control, quality assurance, safety, radiation protection and control, environmental compliance and regulatory compliance, and electronic communications (collectively, "Site Rules"), provided that in each case copies of such Site Rules have previously been provided to Contractor's Authorized Representative. If at any time during the term of this Agreement, Contractor or its Personnel fail to comply with the Site Rules, Owners reserve the right to exercise all its legal remedies under this Agreement including the right to refuse site entry to or have removed from the site Contractor or its Personnel. It is Owners' expectation that these site requirements be communicated by Contractor to its Personnel before they arrive at any of Owners' locations.

28.2 Asbestos Responsibility. Certain areas and components of the nuclear plant for which Contractor has contracted to perform work may contain asbestos. As used in this Section, the term "asbestos" includes "asbestos-containing material" and "presumed asbestos-containing material", as these terms are defined in 29 C.F.R. § 1926.1101 and 29 C.F.R. § 1910.1001. Areas within the plant which are known by SNC to contain asbestos are posted. Material Safety Data Sheets which set forth the quantity in each of the types of asbestos known to be present at the plant are available from the SNC's employee responsible for coordinating the performance of the task that Contractor has been contracted to perform ("SNC's cognizant individual") for inspection. However, it is Contractor's responsibility as a Contractor to exercise caution while at the Site in light of the potential that the area in which Contractor is working may contain asbestos. Contractor shall take the following precautions, unless advised otherwise in writing by SNC's cognizant individual: (1) Contractor must check for postings in the area and contact SNC's cognizant individual to determine whether SNC is aware of any asbestos in the area or components in which Contractor will be working, and (2) even if SNC's cognizant individual is not aware of asbestos in the area or component, Contractor must be sensitive to the potential that asbestos might exist. If Contractor determines that there is a potential that asbestos exists in the work area or component, Contractor shall stop work and notify SNC to investigate the potential asbestos-containing material to determine if in fact the material contains asbestos. If the material is found to be asbestos, Contractor must coordinate any related Work with SNC. Under no circumstances shall work continue when asbestos is discovered without the specific approval of SNC.

28.3 Lifetime Exposure Records. Southern Nuclear policy (applicable after fuel received on Site) administratively limits annual radiation exposure to 2000 millirem, and lifetime radiation exposure to less than the worker's age in rem or 50 rem (whichever is more restrictive), without obtaining special approvals. In order to maintain exposures below these limits, the Contractor is requested to contact the on-call site health physics managers prior to furnishing any worker on site with an exposure level which exceeds, or is projected to exceed, these limits.

28.4 Required Instruction. Contractor acknowledges that its Personnel may be required to complete successfully indoctrination classes and similar instructional classes concerning the Site Rules before admission to, or the performance of Work on, the Site. Owners will not be liable for and will not be required to compensate or reimburse Contractor for any demobilization costs associated with any Personnel who fails to comply with the Site Rules or who terminates employment or has employment terminated in connection with the Site Rules, regardless of the length of employment of or amount of services performed by such Personnel.

28.5 Zero Tolerance Policy on Firearms. Owners have a zero tolerance policy on firearms being brought onto Owners' property. Under no circumstance is a Contractor's employee, agent, or representative to bring firearms, explosives, or any other incendiary devices onto any property owned or operated by Owners. This prohibition includes leaving such items in a vehicle that is parked in Owners' parking lot. Violation of this policy could result in Contractor or its Personnel being barred from all property owned or operated by Owners or its Affiliates.

28.6 Safety. Contractor will be solely responsible for conforming to safety practices dictated by the nature and condition of the Work while at the Site including compliance with OSHA.

28.7 Reporting of Accidents and Noncompliance with Safety Requirements. Contractor will promptly report to Owners, on such form and in such detail prescribed below, all accidents causing personal injury or property damage, and other unsafe acts or conditions, arising from or otherwise connected with performance of the Work. In the event Owners provide written notification to Contractor of any noncompliance with the provisions of this Section, and Contractor fails or refuses to take corrective action promptly in a manner acceptable to Owners, in Owners' sole discretion, such failure or refusal will constitute a material breach of the Agreement. Owners will not be obligated to identify, and notify Contractor of, noncompliance with Section, and any failure by Owners to identify, and notify Contractor of, such noncompliance (including, without limitation, patent noncompliance) will not relieve Contractor of any obligation or liability under the Agreement.

28.8 Medical/Injuries Reporting. First aid will be provided at an on-site medical facility to be staffed and managed by a Contractor-Managed Subcontractor. Injuries that require treatment beyond first aid will follow Site specific emergency response procedures. Contractor shall immediately notify the Owners' Authorized Representative of any recordable injury, serious incident, occupational illness or potential serious hazard to personnel on the Construction Site. Contractor shall submit a detailed, written report to Southern Nuclear within 48 hours of the recordable injury, serious incident, or occupational illness. The injury report will contain the following information:

- Name of injured person and employee identification number
- Date/Time of injury
- Names of any witnesses and employee identification numbers
- Accident description
- Cause of accident
- Action taken to prevent re-occurrence
- Nature/Extent of injury
- Name of Doctor contacted

28.9 Drug Screening. All Contractor Personnel requiring medical attention on Site or as a result of or relating to the Work performed on Site may be drug screened by Owners in accordance with applicable Law and Owners' Fitness for Duty Program.

28.10 OSHA 300 Log. Contractor shall post and keep current their OSHA 300 Log at its on-site office while Contractor is performing Work for Owners. A copy of this OSHA 300 Log will be provided to Owners' representatives upon request.

28.11 Injury Reporting. Contractor's Authorized Representative is responsible for reporting all serious incidents, injuries, and occupational illnesses per Section 28.8. Contractor shall perform an investigation, and an Owner representative may participate in the investigation as determined by Owners and Contractor. The investigation results and corrective actions must be provided to Owners and Owners reserve the right to require additional corrective measures.

28.12 Reporting Applicability. For clarity, the above reporting obligation and other requirements in this Article 28 shall only arise in connection with the performance of Work at or on Owners' property.

## ARTICLE 29

## UNESCORTED ACCESS REQUIREMENTS

29.1 Unescorted Access Requirements. The provisions in this Article 29 shall apply only to personnel who are applying for or have been granted unescorted access to VEGP Units 1 and 2, to Unit 3 after Owners have notified Contractor that the requirements of 10 C.F.R. § 73.56 apply to Unit 3, or to Unit 4 after Owners have notified Contractor that the requirements of 10 C.F.R. § 73.56 apply to Unit 4. All personnel granted unescorted access must be screened in accordance with the requirements of 10 C.F.R. § 73.56, 10 C.F.R. § 73.57, 10 C.F.R. § 26, and guidance of NEI 03.01 latest revision, Nuclear Energy Institute Nuclear Power Plant Access

Authorization Program. Suitability for unescorted access will be based on the results of this screening and must show that the individual is trustworthy and reliable and will not pose a risk to the health and safety of other workers or the public. Contractor is responsible for providing a list of its Personnel that will be visiting the Site at least twenty-four (24) hours prior to its Personnel reporting to the jobsite. The list shall include the last four digits of the employees' social security numbers and shall be submitted to Southern Nuclear's service administrator / cognizant individual named in the applicable blanket order release.

29.2 Procedures for Obtaining Access .

29.2.1 Contractor must have its Personnel screened by Southern Nuclear before unescorted access can be granted. To initiate the screening process, access application forms for the Contractor and its Personnel must be completed and mailed to the address listed below as soon as possible before access is required. Allow a minimum of two (2) weeks for processing applications requiring for background investigations. Application forms and additional information may be obtained by writing or calling:

Southern Nuclear Operating Company, Inc.
Attn: Nuclear Fleet Security Department Bin B017
P.O. Box 1295
Birmingham, AL 35201
Telephone: 800-273-8158

29.2.2 The access screening and qualification process for unescorted access authorization includes: (a) verified identity of individual, (b) employment history with suitable inquiry (includes education in lieu of employment and military service as employment), (c) a credit history review, (d) character and reputation determination, (e) a psychological assessment, (f) FBI criminal history review, (g) pre-access drug/alcohol testing and (h) plant training. The individual shall be subject to SNC's approved behavior observation program immediately following authorizing Unescorted Access Authorization/Unescorted Access (UAA/UA). Background investigations will be processed by the SNC's Nuclear Fleet Security Department in Birmingham, Alabama and will be initiated upon receipt of properly completed application forms from Contractor. The remainder of the access process will normally be conducted at the nuclear plant and should be coordinated through Contractor's contact point at the Plant or the Plant Security Access Coordinator.

29.2.3 Contractor is responsible for assuring that its Personnel arrive at the time and location scheduled for access processing at the Plant.

29.2.4 Contractor and its Personnel that have successfully completed all of the required access elements which were reviewed by a reviewing official who then made an access determination relative to the individual's trustworthiness, reliability and fitness for duty, will be issued a badge for unescorted access. Contractor and its Personnel that do not successfully complete all requirements will be informed of the reasons for denial of access and be given the opportunity to request a review of those access denial decisions that are based on background investigation, criminal history, psychological assessment or fitness for duty.

29.3 Procedures for Terminating Access/Legal Action Reporting .

29.3.1 Contractor is responsible for ensuring that its Personnel report all legal actions to which they are subject and that occur after they are granted access to the Plant. A report of legal action must be made immediately on arrival for work on the first day or first shift following the legal action. The report must be made before the worker enters a nuclear site Protected Area. If the worker's immediate supervisor is not available, the report should be made to the next level of supervision in the work group.

(i) The term "legal action" is defined as a formal action taken by a law enforcement authority or court of law, including being held, detained, take into custody, charged, arrested, indicted, fined, forfeited bond, cited, or convicted for a violation of any law, regulation, or ordinance. It includes felony, misdemeanor, serious traffic offenses, serious civil charges, or military charges.

(ii) A serious civil charge includes, but is not limited to, the following: a civil judgment, tax lien, civil restraining order, breach of peace, fraud, malicious conduct or gross negligence.

(iii) Legal action reporting does not include minor misdemeanors such as parking tickets or minor traffic violations such as moving violations when the individual was not physically taken into custody. It does not include minor civil actions such as zoning violations.

(iv) Any additional legal action occurring while the individual is in the judicial process - and until the matter is fully dispositioned - must be reported to supervision. For example, if an individual's case is continued or postponed until a future court date that status must be reported to supervision. Personnel are also required to report the final disposition to supervision.

(v) Legal action reporting also includes the mandated implementation of a plan for treatment or mitigation in order to avoid a permanent record of an arrest or conviction in response to the following activities:

(a) The use, sale or possession of illegal drugs;

(b) The abuse of legal drugs or alcohol; or

(c) The refusal to take a drug or alcohol test (administered by a law enforcement authority or under direction of a court of law).

29.3.2 Contractor is responsible for notifying plant security to terminate its employee's badge and access authorization within 24 hours following the last shift that the individual is scheduled to work at the Site, or in the event an individual is terminated for cause, the notification to Southern Nuclear security representatives will be made simultaneous of such termination.

29.4 Representatives' Access . All Personnel who require access to the vital areas of the Site are required to pass the general employee training (G.E.T.), fitness for duty and background screening before being granted unescorted access. Southern Nuclear will not reimburse to Contractor any cost incurred by Contractor (e.g., wages, per diem, travel expense) for Personnel who fail to report to work after completion of all test requirements, choose not to complete, or fail to pass the above prequalification.

## ARTICLE 30

## FITNESS FOR DUTY

30.1 Southern Nuclear Fitness for Duty Program . The Nuclear Regulatory Commission's ("NRC") Fitness For Duty ("FFD") regulatory requirements, codified in 10 C.F.R. § 26, and effective on April 30, 2008, require licensees authorized to construct and operate nuclear power reactors to implement an FFD program that includes contract personnel such as Contractor and its Personnel. Contractor Personnel will be evaluated and tested under Southern Nuclear's program, and Southern Nuclear will cover Contractor Personnel under Southern Nuclear's program including, as applicable, a behavioral observation program. Contractor agrees that Contractor accepts and shall strictly adhere to the following requirements:

(i) That Contractor will adhere to Southern Nuclear's Fitness for Duty policy.

(ii) That Contractor supervisory representatives, to the extent that they are covered by 10 C.F.R. Part 26, will be trained in techniques and procedures for initiating appropriate corrective action.

(iii) That Southern Nuclear is responsible to the NRC for maintaining an effective FFD program and that duly authorized representatives of the NRC may inspect, copy or take away copies of reports related to the implementation of Southern Nuclear's FFD program under scope of contracted activities.

(iv) That Contractor shall ensure Contractor Personnel reporting to work at Southern Nuclear's facilities are fit for duty within the scope of 10 C.F.R. Part 26 and able to fully perform the assigned work activities.

(v) Contractor shall ensure that all its Personnel comply with Owners' behavioral observation requirements including, but not limited to, reporting any observation of impairment or unfitness regardless of cause.

(vi) That all Contractor Personnel report to work physically fit to perform all their job duties and that the Contractor shall consider the scope of work required for each contract employee and the physical and mental requirements for each job (e.g., ladder climbing; work at elevations; working in extreme temperatures; heavy lifting, prolonged walking/standing, cognitive ability). Prior to an assignment under this Agreement, the Contractor shall exercise due diligence to ensure that its Personnel who have pre-existing medical conditions that might contraindicate their work in these environments are appropriately evaluated prior to assignment at Owners' nuclear facilities.

(vii) When Owners notify Contractor when the requirements of 10 C.F.R. § 73.56 are expected to apply to Unit 3 and/or Unit 4, Owners will also notify Contractor that the requirements of this Section 30.1(vii) apply. Contractor shall comply with 10 C.F.R. § 26, subpart I, managing fatigue, effective as March 31, 2008 and implemented by Southern Nuclear as of September 30, 2009. Contractor shall ensure that its Personnel performing covered work on-Site shall comply with the work hour rules and effectively manage fatigue per the requirements of subpart I. Compliance with the work hour controls include, but are not limited to, ensuring that Contractor Personnel report to work free of fatigue and have had a minimum 34-hour break in the 9-day calendar period prior to assignment to perform covered work. That the Contractor shall also track work hours of all Contractor Personnel performing covered work on-site to ensure compliance with the subpart I work hour controls and provide annual work hour reports to Southern Nuclear Safety & Health Department, FFD program manager by February 1 of the current year for the prior year.

(viii) To the extent required by 10 C.F.R. § 26.35, Contractor will have or cause its Subcontractors to have, a compliant Employee Assistance Program.

30.2 FFD Access Requirements . The provisions of this Section 30.2 only apply to those individuals not covered by the unescorted access provisions in Article 29. When Owners notify Contractor when the requirements of 10 C.F.R. § 73.56 are expected to apply to Unit 3 and/or Unit 4, Owners will also notify Contractor of the date when FFD access per this Section 30.2 is no longer applicable. All personnel granted FFD access must be screened in accordance with the requirements of 10 C.F.R. Part 26, 10 C.F.R. § 73.56 and NEI 06-06. Suitability for FFD access will be based on the results of this screening and must show that the individual is trustworthy and reliable and will not pose a risk to the health and safety of other workers or the public.

30.3 Scheduling of Work . This Section 30.3 only applies to Personnel who have been granted unescorted access pursuant to Article 29. Contractor shall provide work schedules of Personnel with unescorted nuclear access pursuant to Article 29 who are performing risk significant (covered) work to Owners' designated FFD representative a minimum of 24 hours in advance of arrival to designated work site for review and approval by Southern Nuclear to ensure the work schedules for such Personnel are in compliance with 10 C.F.R. § 26, subpart I, "Managing Fatigue." Risk significant (covered) work will be determined by Southern Nuclear. Contractor shall obtain written approval from Southern Nuclear of such proposed work schedule. At a minimum, such proposed schedule shall include names of all Contractor Personnel, number of shifts per day, hours per shift, and number of days per week and meet the minimum days off per subpart I. Contractor shall strictly adhere to such approved work schedules and work scope. A representative of SNC shall be on site while Contractor is performing work at SNC's nuclear facilities. Contractor shall obtain approval from SNC prior to any work being performed outside of such approved work schedule, out-of-shift, on holidays, or weekends.

30.4 Work Hour Controls/Limitations per 10 C.F.R. § 26, subpart I, "Managing Fatigue" . This Section 30.4 only applies to Personnel who have been granted unescorted access pursuant to Article 29. Contractor shall ensure that all of its Personnel with unescorted nuclear access comply with 10 C.F.R. § 26, subpart I work hour controls and limits; while performing covered work inside the Owner controlled and protected areas of the licensee facility. 10 C.F.R. § 26 subpart I and applicable Southern Nuclear procedures limit work hours and requires minimum days off for Personnel with unescorted access; while inside the Owner controlled area performing risk significant (covered) work. Risk significant (covered) work will be determined by Southern Nuclear. Without prior documented approval of SNC, no individual shall work more than 16 hours in any 24-hour period, more than hours in any 48-hour period, more than 72 hours in any 7-day period, including within shift breaks, and are required 34 hours off in any 9-day period. Contractor shall:

(i) Monitor the work hours of Contractor's Personnel,

(ii) Provide documented actual work hours, including start and stop times,

(iii) Obtain appropriate approval from SNC prior to any worker exceeding the limitations set forth in 10 C.F.R. § 26, subpart I; and

(iv) Ensure fatigue assessments are conducted on Contractor's Personnel under the following conditions:

(a) For Cause - if an observed condition of impaired individual alertness creating a reasonable suspicion that an individual is not fit to safely and competently perform his or her duties;

(b) Self-Declaration - Conducted in response to an individual's self-declaration to his or her supervisor that he or she is not fit to safely and competently perform his or her duties;

(c) Post-Event - Conducted in response to events requiring post-event drug and alcohol testing as specified in 10 C.F.R. § 26.31(c); and,

(d) Follow-Up - If a fatigue assessment was conducted after for cause or in response to a self-declaration, and the Contractor returns the individual to duty following a break of less than ten (v) hours in duration, Contractor shall reassess the individual for fatigue as well as the need to implement controls and conditions before permitting the individual to resume performing any duties.

30.5 Personnel Denied Access to Nuclear Facility. Contractor is responsible for assuring that any of its Personnel who have been denied access at a nuclear plant or removed from activities covered under the scope of 10 C.F.R. § 73.56, 10 C.F.R. § 73.57, NEI 03-01 latest revision, or 10 C.F.R. § 26 at any other nuclear plant are not assigned to SNC's nuclear plant and do not perform any Work covered by this Agreement without the knowledge and consent of SNC.

## ARTICLE 31

## FREE FLOW OF INFORMATION

31.1 Free Flow of Information Compliance . Contractor agrees to conduct its activities, and to ensure that its Personnel conduct activities, in full compliance with the requirements of

Section 211 of the Energy Reorganization Act of 1974, as amended (the "ERA") and 10 C.F.R. § 50.7.

31.2 Work Environment. Contractor will foster a safety conscious work environment ("SCWE") in which its employees feel free to raise concerns without fear of harassment, intimidation, retaliation or discrimination.

31.3 Project ECP and CAP. Contractor and its Subcontractors and their respective Personnel will be subject to SNC's project-specific employee concerns and corrective action programs and procedures at all locations where Work under this Agreement is being performed and will advise their personnel that they are entitled and encouraged to raise safety concerns to the Contractor's management, to Owners, and to the NRC without fear of discharge or other discrimination. SNC's programs to which Contractor and its subcontractors and their respective employees, agents, and personnel are subject will include a Project Employee Concerns Program (Project ECP) and a Project Corrective Action Program (Project CAP). The Project ECP and Project CAP will be reflected in written policies and procedures, to be provided by Owners to Contractor, that employees may use to raise their concerns, and availability of the Project ECP and Project CAP will be broadly communicated by the Owners to the Contractor and its Subcontractors, and their respective Personnel. To the extent allowed by law and by Owners' obligations to protect and maintain confidentiality of Project ECP information, Owners will make a good faith effort to: (i) promptly notify Contractor of any ECP-related concern, allegation of harassment or intimidation, or nuclear safety or quality concern it receives related to Contractor's or any of its Subcontractors' performance of the Work or to any work performed by any of the Contractor-Managed Subcontractors; (ii) on a periodic basis, but no less than monthly, provide Contractor with an update on the status of any investigation being conducted pursuant to the Project ECP related to Contractor's or any of its Subcontractors' performance of the Work or to any work performed by any of the Contractor-Managed Subcontractors; (iii) within one month after completion of any investigation being conducted pursuant to the Project ECP related to Contractor's or any of its Subcontractors' performance of the Work or to any work performed by any of the Contractor-Managed Subcontractors, provide Contractor with an executive summary of such investigation; and (iv) as such reports are finalized by Project ECP personnel and shared with Owners, but no less than Quarterly, provide Contractor with trends and metrics of Project ECP issues related to Contractor's and its Subcontractors' performance of the Work and to any work performed by the Contractor-Managed Subcontractors.

31.4 Free Flow of Information Training. As part of applicable employee training programs, Contractor will familiarize its employees and require each Subcontractor to familiarize its employees with the requirements of Section 211 of the ERA, 10 C.F.R. § 50.7, and NRC's Form 3. Employee training must also include information on Nuclear Safety Culture and SCWE.

31.5 Contractor's Employment Decisions. All employment decisions for Contractor's employees will be made by Contractor and all employment decisions for a Subcontractor's employees will be made by such Subcontractor. Owners are not a joint employer with Contractor or its Subcontractors and shall not direct or control Contractor's employees or a Subcontractor's employees. Contractor will conduct a SCWE review of any adverse employment action in coordination with Owners. Contractor will ensure its activities are in full compliance with the ERA and 10 C.F.R. § 50.7.

31.6 Notification of Harassment or Intimidation Allegation. Contractor will promptly notify Owners of any allegation or complaint of harassment or intimidation in connection with the Work under Section 211 of the ERA and 10 C.F.R. § 50.7. Contractor will inform Owners of any proceeding relating to such allegation or complaint, and will inform Owners promptly of any enforcement action or adverse employment action which it plans to take with respect to an employee who has made such an allegation or complaint to the extent it arises out of performance of the Work. For allegations or complaints of harassment or intimidation against Contractor received by Owners, Owners will provide notice to Contractor in accordance with Section 31.3.

31.7 Adjudicatory Documents. Contractor will promptly furnish Owners' Project ECP representative at the Site with copies of all adjudicatory documents relating to a proceeding involving allegations of harassment or intimidation under Section 211 of the ERA or 10 C.F.R. § 50.7 to the extent these proceedings arise out of performance of the Work. These documents include complaints, hearing requests, notices, pleadings, discovery requests, briefs, orders, decisions and appeals.

31.8 Nuclear Safety or Quality Concern. Within two Business Days of Contractor's receipt of a nuclear safety or quality concern relating to the Work, Contractor will provide notice of such concern to Owners' Project ECP representative at the Site. Contractor will also ensure associated records and reports are maintained in accordance with applicable retention policies as specified by NRC regulations, and provide a copy of such records at the request of Owners' Project ECP representative. Upon Owners' receipt of a nuclear safety or quality concern relating to Contractor arising out of performance of the Work, Owners will provide notice to Contractor in accordance with Section 31.3.

31.9 Auditing of Whistleblower Policies and Investigations. Owners reserve the right to review and audit the effectiveness of Contractor's policies and procedures, to review any investigation performed by Contractor of an allegation of harassment or intimidation related to the Work, to conduct its own investigation into any such allegation, and to request remedial action. Contractor agrees to cooperate with such investigations.

31.10 Termination for Free Flow of Information Violation. Contractor agrees that (i) any actions it takes with respect to its employees in connection with the Work, which Owners, the NRC or the Department of Labor determines is in violation of Section 211 of the ERA or 10 C.F.R. § 50.7, or (ii) any material breach of this Section will constitute a breach of a material provision of this Agreement for the purposes of Section 21.2.

31.11 Indemnification for Free Flow of Information Claims. Contractor agrees to indemnify and hold harmless Owners from any Claims by Contractor's employees and associated costs (including costs of defense, attorney's fees and court costs), expenses, fines, penalties or other liability to the extent such arises from conduct of Contractor which violates Section 211 of the ERA or 10 C.F.R. § 50.7.

31.12 Communication with NRC. In accordance with 10 C.F.R. § 50.7, this Agreement does not in any way prohibit or restrict or otherwise discourage the free flow of information from Contractor to the NRC. Further, any associated subcontract affecting the terms, compensation, conditions and privileges of employment will not contain any provision which prohibits, restricts or otherwise discourages the free flow of information to the NRC.

## ARTICLE 32

## NO TOLERATION OF UNACCEPTABLE BEHAVIORS BY CONTRACTOR

32.1 Behavior Standards . Contractor and its Personnel shall at all times conduct their business activities pursuant to this Agreement in a highly ethical manner and in compliance with all applicable laws and regulations. Personnel shall not, at any time, exhibit the following behaviors:

- Harassment or unlawful discrimination of any kind or character, including but not limited to conduct or language derogatory to any individual, race, color, religion, age, disability, veteran status, genetic information, gender, sex, sexual orientation, gender identity, national origin, or any classification protected by federal, state or local law, that creates an intimidating, hostile, or offensive working environment. Specific examples include, but are not limited to jokes, pranks, epithets, written or graphic material, or hostility or aversion toward an individual or group on the basis of a legally protected status.
- Any conduct or acts such as threats or violence that creates a hostile, abusive, or intimidating work environment. Examples of such inappropriate behaviors include, but are not limited to fighting, abusive language, inappropriate signage, use or possession of firearms on Owners' property, and destruction of Owners or Owners' employee property at the worksite or the threat of any of the foregoing.
- Work practices that are unsafe or harmful to the natural environment.
- Use of Owners' computers, email, telephone or voice-mail system that in any way involves material that is obscene, pornographic, sexually oriented, threatening, or otherwise derogatory or offensive to any individual, race, color, religion, age, disability, veteran status, genetic information, gender, sex, sexual orientation, gender identity, national origin, or any classification protected by federal, state or local law.
- The use of, being under the influence of, or possession of alcoholic beverages or unlawful drugs on Owners' property.
- Engagement in any activity that creates a conflict of interest or appearance of the same, or that jeopardizes the integrity of Owners or Contractor (including but not limited to providing gifts and gratuities to Owners' employees).

- Posting in any social media forum (Facebook, Twitter, blogs, etc.) or communicating in any other public setting in a manner that does not constitute protected speech and violates any of the provisions of this Agreement, regardless of whether those postings or communication are made using Owners resources, Contractor resources, or any Personnel's resources, during or outside of work hours. Examples include, but are not limited to, divulging Protected Information or making harassing or discriminating statements about, or directed at, employees or customers of Owners or its Affiliates. No Personnel will imply or in any way indicate that he/she speaks on behalf of Owners or its Affiliates in any social media forum or any other public setting. Owners reserve the right to monitor all communication made by Contractor's Personnel on Owners' equipment, including laptops, cellular telephones, and portable computing devices (e.g., Blackberry, Smart Phones) and Contractor's Personnel have no reasonable expectation of privacy in such communications. Owners' right to monitor includes, but is not limited to, the right to archive, store, and forensically recover electronic communications on Owners' equipment.

32.2 Compliance with Required Behavior Standards. Contractor shall communicate these required behavior standards to its Personnel and Subcontractors and their Personnel and shall promptly dismiss, or cause its Subcontractors to dismiss, any individual who has violated these standards. Contractor and its Subcontractors shall inform their Personnel that they will maintain a "no tolerance" policy for violation of the required behavior standards. In the event that a Subcontractor or its Personnel violates these behavior standards, Contractor shall require such Subcontractor to promptly institute an educational program designed to raise awareness of and conformity to these behavior standards. In the event that a Subcontractor fails to institute the educational program within thirty (30) Days of notice from Contractor, or there are repeated violations of these standards by such Subcontractor or its Personnel, at Owners' request, Contractor will take prompt action to terminate the applicable Subcontract. If Contractor or any of its Personnel observes an employee of Owners or any of their Affiliates doing, or is ever asked by such an employee to do, something considered to be unethical, illegal, or in violation of these behavior standards, Contractor shall notify Owners' management immediately or call Workplace Ethics at (1-800-754-9452) or such other number as directed by Owners.

## ARTICLE 33

## NON-ENGLISH SPEAKING CONTRACTOR WORKERS

33.1 Provision of English Speaking Personnel. Contractor shall at all times assure that an English speaking representative of Contractor is provided for non-English speaking Personnel and Subcontractors. The English speaking representative must have the ability to communicate with and translate the foreign language of all non-English speaking Personnel and Subcontractors to assure that the ability to communicate vital information is readily available. If the non-English speaking Personnel or Subcontractors are divided into work groups, it shall remain the responsibility of the Contractor that an English speaking representative of Contractor is provided so as to assure that the ability to communicate vital information is still readily available to all non-English speaking Personnel and Subcontractors.

33.2 Translations. Contractor represents and warrants that it has communicated and translated to its non-English speaking Personnel and Subcontractors including all information and training required by applicable Law and all other safety and health requirements, in addition to all job related duties. These requirements include but are not limited to OSHA, the Contractor’s safety program, the contract documents including contract safety requirements, any relevant manufacturer’s information such as Material Safety Data Sheets, and the specific project safety plan for the work to be performed for Owners, in addition to any relevant hazards and special site conditions that Owners have notified Contractor may be encountered by Contractor and or its Personnel or Subcontractors.

33.3 Notice. In the event that Contractor or a Subcontractor will cause Non-English Speaking Personnel or Subcontractors to be engaged in Work at the Site subject to Owners’ Part 26 Fitness for Duty program, Contractor shall provide written notice to Owners at least thirty (30) days prior to the arrival of the Non-English Speaking Personnel or Subcontractors at the Site.

33.4 Limitations for Certain Access and Screening Requirements. This Section 33.4 applies only to personnel for whom Contractor requests screening pursuant to Article 29 or to whom 10 C.F.R. Part 26 Subparts A through H, N, and O would apply in the performance of their duties. Certain aspects of the screening process required by applicable Law are only available in English as of the Effective Date. Nothing in this Article 33 limits Owners’ rights pursuant to Articles 29 and 30 with respect to any access or fitness for duty determination.

## ARTICLE 34

## BENEFITED PARTIES

Contractor understands and agrees that GPC is entering into this Agreement not only for its own benefit but also and equally for the direct benefit of Owners. By agreement, SNC has the right and obligation to construct, operate and maintain generating plants, which are owned jointly by GPC and the other Owners, and SNC has the right to enter into agreements for exercising said rights and performing said obligations. As their interests appear, it is further agreed that each and every right, benefit and remedy accruing to GPC likewise accrues to the Owners including but not limited to the right to enforce this Agreement in their own name or names. Notwithstanding the foregoing, as between GPC, Owners, and Contractor, GPC shall remit (on behalf of Owners) all payments to Contractor hereunder, and Contractor shall submit all invoices to GPC for payment. Owners represent that Owners are the sole present owners (subject to mortgage indentures) of the Facility to which the Work relates and that GPC is authorized to bind, and does bind, all present Owners to the terms of this Agreement including the limitations of liability set forth in this Agreement. In the event that any other entity obtains any ownership interest in a facility for which the Work is performed, then Owners agree to bind such entity to such limitations of liability.

## ARTICLE 35

## QUALIFICATIONS AND PROTECTION OF ASSIGNED PERSONNEL

35.1 Contractor's Personnel . Contractor shall comply with applicable labor and immigration Laws that may impact Contractor's Work under this Agreement, including the Immigration Reform and Control Act of 1986 and Form I-9 requirements, by performing the required employment eligibility and verification checks and maintaining the required employment records as included therein. By providing an employee of Contractor or a Subcontractor to engage in any portion of the Work under this Agreement, Contractor warrants and represents that it has completed the screening measures described in this Section 35.1 with respect to such employee, if applicable, and that such screening measures did not reveal any information that could adversely affect such employee's suitability for employment or engagement by Contractor or Subcontractor or competence or ability to perform duties under this Agreement. If in doubt as to whether a suitability, competence or ability concern exists, Contractor shall discuss with Owners the relevant facts of such situation and Owners will determine, in their sole discretion, whether such Person should be allowed to perform any of the Work. Owners, in their sole discretion, shall have the option of barring from the Site any Person whom Owners determine does not meet the qualification requirements set forth above. In all circumstances, Contractor shall ensure that the substance and manner of any and all screening measures performed by Contractor pursuant to this Section conform to applicable Law. Owners shall have the right to bar from the Site any Person employed or engaged by Contractor, its Personnel or an Invitee who engages in misconduct or is incompetent or negligent in the Owners' sole judgment while on the Site or while performing Work, or whom Owners have previously terminated for cause or otherwise dismissed or barred from the Site. Upon request of Owners, Contractor shall immediately remove those Persons to whom Owners object from the Site and shall not allow the further performance of Work by those Persons. In addition, in the event that Contractor learns of any such misconduct, incompetence or negligence independent of Owners' objection, Contractor shall remove such Persons from the Site, shall not allow any further performance of Work by such Persons and shall promptly notify Owners of such misconduct, incompetence or negligence and the actions taken by Contractor as a result thereof. Any cost for replacement of such Persons removed by Contractor pursuant to the preceding sentence shall be at Contractor's expense.

35.2 Respirator Protection . For any Work at the Site that may expose any of Contractor's Personnel or Invitees to sources of radiation or require them to wear respiratory protection, Contractor shall require each of these Persons, prior to entering any radiation area or wearing respiratory protection, to undergo a physical examination to determine if occupational radiation exposure or the wearing of respiratory protection should be avoided because of any medical condition or other circumstance, and in addition, to undergo such physical examination as may be required by applicable Law or by a Government Authority having jurisdiction. Contractor shall keep a record of such physical examinations available for inspection by Owners as permitted under applicable Law. Owners will assist Contractor in defining the applicable requirements, if requested.

## ARTICLE 36

## RECORDS AND AUDIT

36.1 Technical Documentation. Except to the extent applicable Laws require a longer retention, Contractor shall maintain and shall cause its Subcontractors to maintain Work records for a period of three (3) years after Final Completion or such longer period as required by applicable Laws.

36.2 Accounting Records. Except to the extent applicable Laws require a longer retention, Contractor shall maintain and shall cause its Subcontractors to maintain complete accounting records relating to the Work performed or provided under this Agreement including all Reimbursable Costs in accordance with generally accepted accounting principles in the United States, as set forth in pronouncements of the Financial Accounting Standards Board (and its predecessors) and the American Institute of Certified Public Accountants, for a period of seven (7) years after Final Completion or such longer period as required by Law, except that records relating to Sales Taxes for such items must be retained for seven (7) years as specified in Section 36.5.

36.3 Maintenance of Records Generally. Notwithstanding anything in Section 36.1 or 36.2 to the contrary, Contractor shall ensure to the extent required that its maintenance of records complies with the applicable provisions of 10 C.F.R. § 50.71 and other applicable Laws, including, but not limited to, NRC regulations, until such time Contractor delivers such records to Owners in accordance with this Agreement.

36.4 Right to Audit. If Owners request verification of Reimbursable Costs or any other amounts payable or invoiced under this Agreement, Owners or Owners' independent auditor shall be entitled to examine and audit Contractor's records and books related to such amounts and provide a report to Owners. Such audit will be conducted during business hours and provide each Owner with a reasonable opportunity to verify that all costs and charges have been properly invoiced and requested in accordance with the terms of this Agreement. Notwithstanding anything in this Agreement to the contrary, Owners shall not be entitled to audit any information that would enable Owners to determine the make-up of any lump sum, or any fixed or established amounts, rates or multipliers permitted under this Agreement (other than escalation indices). If an audit by the auditor demonstrates that amounts paid by Owners to Contractor were incorrectly charged, then Owners shall be entitled upon demand to a refund from Contractor of such over-charges plus interest since the date of payment of the over-charges at a rate equal to the Prime Rate plus two percent (2%). Any such refunds owed by Contractor to the Owners may be offset by the Owners from any amounts otherwise payable to Contractor at any time.

36.5 NRC. Notwithstanding anything in this Agreement to the contrary, Owners shall not be restricted from any audit rights that they are required to have in order to comply with applicable Laws, including without limitation the requirements of the NRC.

36.6 Sales Tax Records. Contractor shall fully cooperate with Owners in connection with the reporting of (a) any Sales Taxes payable with respect to the Work and (b) any assessment, refund, Claim or proceeding relating to Sales Taxes payable with respect to the Work. Contractor shall use commercially reasonable efforts to require its Subcontractors to provide to Contractor the information and data Contractor may reasonably request for purposes of complying with this Section and otherwise fully cooperate with Owners. Contractor shall retain, and shall require its Subcontractors to retain, copies of such documentation and the documentation concerning purchases relating to the Work or the payment of Sales Taxes, if any, for a period of not less than seven (7) years. Contractor shall use commercially reasonable efforts to ensure that its contracts with Subcontractors effectuate the provisions of this Section. Contractor's obligations under this Section shall survive the termination, cancellation or expiration of this Agreement for any reason and shall last so long as is necessary to resolve matters regarding Taxes attributable to the Work. The costs incurred in complying with this Section shall be Reimbursable Costs.

36.7 Acknowledgement of Owners' Co-ownership Agreements . Contractor acknowledges that pursuant to the Ownership Agreement and the Development Agreement, each of the Owners has informational and audit rights relating to the development, planning, design, licensing, acquisition, construction, completion, startup and commissioning of the Units and the associated costs to be shared among the Owners. Those rights include audits of the performance of Georgia Power Company, as agent for the other Owners, the provision of relevant information to the Owners relating to the development, planning, design, licensing, acquisition, construction, completion, startup and commissioning of the Units, and audits of Georgia Power Company or Southern Nuclear of the costs associated with the Units which are charged to or paid by the Owners. Contractor shall cooperate with Southern Nuclear, Georgia Power Company and the other Owners and their representatives in connection with these informational and audit rights, and will upon request by Georgia Power Company or Southern Nuclear provide information relating to this Agreement and Contractor's performance hereunder, to the extent that Owners are entitled to such information pursuant to the other provisions of this Agreement.

## ARTICLE 37

## TAXES

37.1 Sales Tax .

37.1.1 Contractor and Subcontractor expenses to comply with nonresident contractor sales tax bond and nonresident subcontractor bonds prescribed by Ga. Code Ann. § 48-13-31 and Ga. Code Ann. § 48-8-63 shall be reimbursed by Owners. Expenses include, but are not limited to application fees, annual surety bond costs, and bond termination fees.

37.1.2 For the avoidance of doubt, Taxes, including Sales Tax on Plant Equipment and Materials procured by Owners and provided to Contractor and its Subcontractors for incorporation into the Facility are for the account of Owners. Taxes, including Sales Tax, on Contractor (and its subcontractors) Construction Equipment, Construction Materials and indirect materials are payable by Contractor (and its subcontractors), and shall be reimbursed by Owners pursuant to Section 7.1.1(vi).

37.2 Property Tax .

37.2.1 Property Tax shall mean ad valorem taxes imposed on real and business personal property, and construction work in process.

37.2.2 Property Tax assessments of Contractor and its Subcontractors as they pertain to the Work shall be reimbursed by Owners to Contractor.

37.3 Cooperation and Audit .

37.3.1 Owners and Contractor shall, and Contractor shall cause each Subcontractor to cooperate in good faith with each other, and use their commercially reasonably efforts to minimize sales or use relating to this Agreement and the Work, including taking advantage of applicable exemptions and consulting and cooperating in good faith with each other in order to effectively handle and contest any audit, examination, investigation, or administrative, court or other proceeding. In connection therewith, Contractor shall, and shall cause its Subcontractors to, assign to Owners its rights to any refund of Sales Tax, Property Tax, or other Taxes which have been paid or reimbursed by Owners in order to enable Owners to contest the determination of taxability and recover any overpayment of such Taxes. Contractor shall grant or cause to be granted to, and shall cause its Affiliates and Subcontractors to grant to, Owners or Owners' representatives (subject to appropriate non-disclosure agreements being signed) access at all reasonable times during the course of the Work and thereafter until the later of thirty days following the expiration of the applicable statute of limitations or the resolution of any Claim in respect of Sales Tax and Property Tax to all of the information, books, and records relating to Sales Tax and Property Tax matters pertaining to the Work within their respective possession or control, and shall make their respective employees and agents available on a mutually convenient basis in order to answer questions regarding such books and records. Contractor shall also furnish or cause to be furnished to Owners or Owners' representatives the assistance and cooperation of personnel of Contractor, its Affiliates, and Subcontractors, as Owners may reasonably request in connection with such Tax matters.

37.3.2 Provided that Owners have timely performed their obligations under this Article, Contractor shall defend, indemnify and hold harmless the Owners and Owners' Interests from and against any liabilities arising or resulting from Contractor's or any Subcontractor's failure to (a) make any payment of Sales Tax, Property Tax, or other Taxes, interest or penalties when due, (b) comply with reporting or return filing obligations, and/or (c) provide or obtain the necessary information or exemption forms to or from its or their respective Subcontractors, or otherwise comply with the requirements of any applicable exemption from Taxes.

37.3.3 Owners shall be responsible for and shall indemnify, defend and hold harmless Contractor and Contractor Interests from and against any Taxes, interest or penalties imposed on any of the foregoing and that arise as a result of inaccuracies or omissions from executing Owners' tax minimization strategy.

37.3.4 Owners shall reimburse Contractor with respect to the defense of any Claim or assessment related to Sales Tax, Property Tax, or other Taxes for which Owner is liable hereunder in respect of the Work. Consistent with other notice provisions in this Agreement, Contractor shall notify Owner in writing of any audit or assessment of Contractor by a Taxing Authority covering Sales Tax, Property Tax, or other Taxes where Contractor has the right to be indemnified.

## ARTICLE 38

## DISPUTE RESOLUTION

38.1 Definition of Claim . A "Contract Claim" is a written demand or assertion by one of the Parties submitted to the other Party seeking, as a matter of right, adjustment or interpretation of Agreement terms, payment of money, adjustment to the Target Completion Date(s), adjustment to the Target Construction Cost, or other relief with respect to the terms of this Agreement. The term “Contract Claim” also includes other disputes and matters in question between Owners and Contractor arising out of or relating to this Agreement (including the breach, termination or validity thereof, and whether arising out of tort or contract).

38.2 Pre-DRB Process. Prior to submitting any Contract Claim for dispute resolution, the Parties will exchange written positions regarding the dispute and senior officers shall meet in person or telephonically to attempt to resolve the dispute. Upon mutual agreement, the Parties will submit disputes to non-binding mediation prior to initiating the dispute resolution board (“DRB”) process set forth in this Article. Pending a determination from the DRB as provided below, Contractor shall proceed diligently with the performance or provision of the work that is the subject of the Contract Claim and all of its other duties and obligations under this Agreement.

38.3 Submittal to DRB. All Contract Claims not resolved by the Parties per Section 38.2 shall be submitted to and decided by the three-member DRB established pursuant to the DRB procedures set forth in Exhibit U. The DRB members shall each be mutually agreeable to the Parties. Upon any vacancy on the DRB, the Parties shall endeavor to agree on a replacement member promptly in accordance with the DRB procedures, notwithstanding whether any Contract Claim then is pending.

38.4 Commencing Dispute Resolution. Either Party may commence the DRB hearing process by providing written notice of the dispute to the other and to the members of the DRB, as provided in the DRB procedures. The initiating Party shall indicate whether the Regular Hearing or Expedited Hearing process is requested. The other Party shall note any objection to the requested process in writing within 5 Business Days of receiving such notice. Any disagreement as to whether the Regular or Expedited Hearing process is applicable to the dispute shall then be determined within 10 Days by the DRB Chair, in accordance with the terms of this Agreement.

38.5 Initial DRB Conference. Within the applicable period set forth in the DRB procedures, the DRB shall hold a telephone conference with the Parties to discuss the Contract Claim and to agree on the hearing date, duration, and the applicable pre-hearing deadlines. The DRB may establish additional procedures and otherwise conduct the dispute resolution process in such manner as it deems appropriate to assure an expeditious and fair resolution of the Contract Claim.

38.6 DRB Hearing Location. Unless otherwise agreed by the Parties, the DRB shall convene all hearings either at the Site or in Atlanta, Georgia.

38.7 Effect of DRB Determination. The written determination of the DRB is binding on the Parties to the extent provided herein, and any remedy contained in such determination shall be implemented and paid within 45 Days of such determination, without prejudice to subsequent arbitration as provided herein. An arbitration solely to compel a Party to comply with the determination of the DRB may be commenced any time after such 45 Day period. The DRB determination itself is subject to further challenge via arbitration which may be initiated by either Party following a determination of the DRB, but only in accordance with the requirements set forth below.

38.7.1 Where either (a) the Contract Claim(s) relate to the withholding or non-payment of Reimbursable Costs (whether such Contract Claim(s) are related or not) and the cumulative value of Reimbursable Costs in dispute exceeds [***], or (b) one or more Contract Claims relating to a single or closely-related series of events or contractual interpretation disagreement involve an aggregate amount in dispute exceeding [***], the Parties may initiate arbitration seeking to overturn the DRB's determination within 45 Days from the date of such determination.

38.7.2 In all other cases (including a dispute within Section 38.7.1 as to which no arbitration is initiated per that Section), the Parties may only initiate arbitration to challenge the DRB's determination within the 60 Day period following achievement of Mechanical Completion of Unit 4. For DRB determinations rendered after such Mechanical Completion date, any arbitration to challenge the DRB's determination must be initiated within 60 Days following such determination.

38.7.3 If no arbitration has been initiated with respect to a Contract Claim within the applicable time periods set forth above, the DRB's determination shall be final and binding in all respects. Judgment thereon may be entered by any court having jurisdiction thereof, and such DRB determination shall be entitled to treatment as a final award rendered in a duly constituted and conducted arbitration in accordance with the provisions of the U.S. Arbitration Act, 9 U.S.C. Section 1, et seq.

38.7.4 For purposes of determining the aggregate amount in dispute as specified in Section 38.7.1(b), the amount associated with all Contract Claims stemming from a single or closely-related series of events or contractual interpretation disagreement shall be added together, but unrelated Contract Claims may not be added together so as to exceed the threshold amount set forth in Section 38.7.1(b). As a special case, it is agreed that all Contract Claims relating to the Subcontract Scope Alignment Process will be considered as stemming from a single or closely-related series of events. If the Parties do not agree on the aggregate amount in dispute for these purposes, the determination of the DRB regarding the aggregate amount in dispute will be final and binding on the Parties.

38.7.5 Pending a final arbitration award overturning or modifying a DRB determination, all DRB determinations will be binding on the Parties and implemented in all respects in good faith.

38.8 Arbitration. Subject to the provisions and time limits of Section 38.7, any dispute arising out of or relating to this Agreement, including the breach, termination or validity thereof, shall be finally resolved by arbitration in accordance with the International Institute for Conflict Prevention and Resolution Rules for Non-Administered Arbitration by three arbitrators, of whom each Party shall designate one in accordance with Rule 5.1. The arbitration shall be governed by the Federal Arbitration Act, 9 U.S.C. §§ 1 et seq., and judgment upon the award rendered by the arbitrator(s) may be entered by any court having jurisdiction thereof. The place of the arbitration shall be Atlanta, Georgia. The arbitration shall consider the Contract Claim(s) involved de novo, provided that the applicable DRB Determination(s) respecting such Contract Claim(s) shall be admissible in evidence and given such weight as the arbitrators may determine.

38.9 Court Proceedings . Notwithstanding anything in this Article to the contrary, a Party may file a complaint, exclusively, in the U.S. District Court for the Southern District of Georgia for the limited purpose of seeking enforcement of the agreement to arbitrate set forth in this Article, or non-exclusively, for the purpose of seeking a judgment upon or enforcement of an arbitration award.

## ARTICLE 39

## NOTICES

All notices specifically related to the terms and conditions of this Agreement or otherwise required under this Agreement shall be sent by nationally recognized overnight courier service or certified mail with return receipt requested to the addresses shown below, with notice to be effective only at the time of receipt thereof.

If to Owners :

Georgia Power Company
Attn: David L. McKinney, Vice President-Nuclear Development
241 Ralph McGill Blvd., NE
BIN 102321
Atlanta, GA 30308

Southern Nuclear Operating Company, Inc.
Attn: Mark D. Rauckhorst
Executive Vice President-Vogtle 3/4 Construction
7825 River Road
BIN 63031
Waynesboro, GA 30830

Balch & Bingham LLP
Attn: M. Stanford Blanton
1710 Sixth Avenue North
Birmingham, AL 35203

If to Contractor :

Bechtel Power Corporation
Attn. T. Troutman, Project Manager
Plant Vogtle 3&4
7825 River Rd.
Building 302 Executive Office
Waynesboro GA, 30830

Bechtel Power Corporation
Attn: C. E. Harris, General Counsel
12011 Sunset Hills Road

Suite 110
Reston, Virginia 20190

Bechtel Power Corporation
Attn: Nuclear Power Business Line Manager
12011 Sunset Hills Road
Suite 110
Reston, Virginia 20190

## ARTICLE 40

## MISCELLANEOUS

40.1 Assignment. Contractor shall not assign this Agreement in whole or in part without the prior written consent of Owners, which consent shall not be unreasonably withheld. Owners shall not assign this Agreement in whole or in part without the prior written consent of Contractor, which consent shall not be unreasonably withheld; provided, however, that (i) this Agreement may, upon prior written notice to Contractor, be assigned in whole by the Owners to the DOE without the prior consent of Contractor; and (ii) this Agreement may, upon prior written notice to Contractor, be assigned by the Owners to the Financing Parties for collateral purposes without the prior consent of Contractor. Except as set forth in this Section 40.1, any assignment of this Agreement by either Party, either by operation of law, order of any court, or pursuant to any plan of merger, consolidation or liquidation, shall be deemed an assignment by such Party for which prior consent is required, and any assignment made without any such consent shall be void and of no effect as between the Parties.

40.2 Non Waiver. The failure of either Party to enforce at any time any of the provisions of this Agreement shall neither be construed as a waiver of such provision nor in any way affect the validity of this Agreement or the right of either Party to enforce each and every provision.

40.3 No Implied Waiver. Unless otherwise expressly provided herein, no waiver by either Party of any provision hereof shall be deemed to have been made unless expressed in writing and signed by such Party.

40.4 Amendments. No waiver, modification, or amendment of any of the provisions of this Agreement shall be binding unless it is in writing and signed by duly authorized officer of each Party.

40.5 Survival. All provisions of this Agreement that expressly or by implication come into or continue in force and effect following expiration or termination of this Agreement shall remain in effect and be enforceable following such expiration or termination, including all provisions of this Agreement that much survive in order to give force and effect to the rights and obligations of the Parties under this Agreement.

40.6 Governing Law. The validity, construction, and performance of this Agreement shall be governed by and interpreted in accordance with the Laws of the State of Georgia, without giving effect to the principles thereof relating to conflicts of Laws.

40.7 Waiver of Jury Trial. EACH PARTY HEREBY IRREVOCABLY WAIVES ALL RIGHT TO TRIAL BY JURY IN ANY ACTION, PROCEEDING OR COUNTERCLAIM (WHETHER BASED ON CONTRACT, TORT OR OTHERWISE) ARISING OUT OF OR RELATING TO THIS AGREEMENT.

40.8 Independent Contractor. Contractor is an independent contractor and nothing contained herein shall be construed as creating (a) any relationship between Owners and Contractor other than that of owners and independent contractor, (b) any relationship whatsoever between Owners and Contractor's Personnel or (c) a fiduciary relationship between Contractor and Owners. Neither Contractor, nor any of its Personnel, are or shall be deemed to be employees of Owners.

40.9 Third Party Beneficiaries. Except as expressly set forth in this Agreement, the provisions of this Agreement are intended for the sole benefit of Owners and Contractor, and the Parties do not intend to create any other third party beneficiaries or otherwise create privity of contract with any other Person.

40.10 Rights Exclusive. The rights and remedies of Owners or Contractor as set forth in this Agreement shall be the exclusive rights or remedies of the Parties. The limitations of liability, indemnities, extension of insurance coverages and other liability protection provided herein for the benefit of Contractor and Owners shall also apply for the benefit of Contractor Interests and Owner Interests and shall apply to the maximum extent permitted by Law, irrespective of the basis of such claim, whether arising at contract (including breach warranty, indemnity, etc.), tort or otherwise, and regardless of the fault, negligence or strict liability.

40.11 Severability. If any provision of this Agreement or the application of this Agreement to any Person or circumstance shall to any extent be held invalid or unenforceable by a court of competent jurisdiction or arbitrators under Article 38, then (i) the remainder of this Agreement and the application of that provision to Persons or circumstances other than those as to which it is specifically held invalid or unenforceable shall not be affected, and every remaining provision of this Agreement shall be valid and binding to the fullest extent permitted by Laws, and (ii) a suitable and equitable provision shall be substituted for such invalid or unenforceable provision in order to carry out, so far as may be valid and enforceable, the intent and purpose of such invalid or unenforceable provision.

40.12 Entire Agreement. This Agreement contains the entire agreement and understanding between the Parties as to the subject matter hereof, and merges and supersedes all prior agreements, commitments, representations, writings and discussions between them with respect to the subject matter hereof. Except as provided in this Section 40.12, neither of the Parties will be bound by any prior obligations, conditions, warranties, or representations with respect to the subject matter hereof.

40.13 Counterparts. This Agreement may be executed in two or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

40.14 Further Assurances. The Parties will execute and deliver such other instruments and documents, and take such other actions, as either Party reasonably requests to evidence or effect the transactions contemplated by this Agreement.

40.15 External Communications. Prior to issuing any external communications regarding the Facility, Contractor shall obtain Owners' prior written approval (approval not to be unreasonably withheld or delayed). Prior to issuing any external communications regarding the Facility which mention Contractor or any of its Subcontractors, Owners shall obtain Contractor's prior written approval (approval not to be unreasonably withheld or delayed).

## ARTICLE 41

## EXECUTIVE OVERSIGHT

41.1 Establishment of Committee. Within thirty (30) Days of the Effective Date, Owners and Contractor shall establish an executive oversight committee (the "Executive Oversight Committee"). The Executive Oversight Committee is not intended to be an approval body or a decision-making body but is intended to facilitate executive-level oversight of the performance of the Work and to provide a forum for discussion of significant issues and/or concerns which may arise in connection with the construction and completion of the Facility.

41.2 Appointment of Executive Sponsors.

41.2.1 The Executive Oversight Committee will be comprised of four (4) members ("Executive Sponsors"), two (2) of whom shall be appointed by Owners and two (2) of whom shall be appointed by Contractor. Each Party shall appoint its Executive Sponsors within fourteen (14) Days of the Effective Date, by giving written notice to the other Party. Each Party may replace either or both of its Executive Sponsors at any time by giving written notice to the other Party.

41.2.2 Unless otherwise agreed by Contractor, the Executive Sponsors appointed by Owners shall occupy board-level positions in GPC's organization. Unless otherwise agreed by Owners, the Executive Sponsors appointed by Contractor shall occupy board level positions in the organization of Contractor or Guarantor. No person shall be appointed as an Executive Sponsor if such person is involved in the day-to-day management of the Vogtle Units 3 and 4 project or any part thereof.

41.3 Meetings. The Executive Oversight Committee shall meet (either in person or by telephone) on a regular basis (no less frequently than quarterly), provided that any Executive Sponsor may request a meeting of the Executive Oversight Committee at any time to discuss a matter requiring urgent attention and the other Executive Sponsors shall make good faith efforts to participate in such meetings as requested.

***[The next page is the signature page.]***

IN WITNESS WHEREOF, the Parties have duly executed this Agreement as of the date first above written.

GEORGIA POWER COMPANY, as an Owner
and as agent for the other Owners

By: /s/Chris Cummiskey
Name: Chris Cummiskey
Title: EVP External Affairs & Nuclear Development

BECHTEL POWER CORPORATION

By: /s/Tyrone P. Troutman, Jr.
Name: Tyrone P. Troutman, Jr.
Title: President

*[Signature Page to Construction Completion Agreement]*

**Exhibit A – Scope of Work / Division of Responsibilities**

Table of Contents

**Exhibit A – Scope of Work / Division of Responsibilities**

## 1. DEFINITIONS

" Core Scope " means each of the following scope items for each Unit:

(a) Containment building, shield building, auxiliary building, annex building, and turbine building;

(b) Each item of Contractor-Managed Subcontract Scope associated with the buildings listed in (a); and

(c) The provision of distributable services to support construction activities associated with the buildings listed in (a).

" Non-Core Scope " – means scope items not falling within the definition of Core Scope.

" Work Package " – means an assembly of documentation which describes a specific scope of Work and provides Construction Supervision with a concise package of information to accomplish that scope.

## 2. SCOPE OF WORK

### 2.1 Contractor's Scope of Work

Except as otherwise provided in the Agreement, Contractor's overall scope of Work is to complete the construction of Vogtle Units 3 and 4 which are two electric generating plants using the Westinghouse AP1000 design as described in the Owners' Updated Final Safety Analysis Report (UFSAR) as of September 30, 2017. Each Unit includes the following buildings and equipment:

- Containment building
- Shield building
- Auxiliary building
- Annex building
- Turbine building
- Diesel generator building
- Radwaste building
- Major equipment including the steam generators, reactor vessel, reactor vessel head, control rod drive mechanisms, main turbine, main turbine generator, turbine deaerator, reactor coolant pumps, containment vessel, cooling towers, main turbine condenser, reactor internals, main step-up transformers, pressurizer, diesel generators, feedwater pumps, circulating water pumps, polar crane, core makeup tanks, moisture separator reheaters, and other equipment and components
- Other balance of plant and yard buildings, equipment, and components

**Exhibit A – Scope of Work / Division of Responsibilities**

The scope of Work to be performed by Contractor and/or its Subcontractors will comprise the following activities:

a. All management of construction on the site and supporting offsite locations (e.g., warehouses), including Contractor's Project Manager, Site Manager, Construction Managers, Area/Building Managers, and Superintendents.

b. Engagement and management of all craft workers on the site.

c. Management of the Contractor-Managed Subcontract Scope.

d. Support of Work Package planning and scoping, preparation of Work Packages, and closeout of Work Packages as described in Section 4.1 below.

e. Field Procurement management for construction materials and equipment.

f. Management of Plant Equipment and Materials at the site including receipt and inspection, warehouse management (onsite and offsite facilities), material coordination/issuance, preventive maintenance, and asset preservation.

g. Management of the use of Owner-provided Construction Equipment and provision of new Construction Equipment as required by Section 4.1.8 of the Agreement.

h. Management of the use of construction utilities (power, water, etc.) provided by the Owners.

i. Quality Control for construction activities for which Contractor is responsible.

j. Construction Testing for which Contractor is responsible, as identified as Contractor's responsibility in Table 2 of Exhibit G, "Mechanical Completion."

k. Quality Assurance (QA) for Contractor's work activities including implementation of the Contractor's Quality Assurance Program which will use and take credit for the Owners' existing quality programs to the extent possible.

l. Develop program and plan for ASME NA and NPT certifications for performing activities governed by ASME Section III which will be integrated with the existing site ASME approach and implement the plan as directed by Owners.

m. Construction training for Contractor and Subcontractor personnel.

n. Site-wide construction safety program.

o. Management of facilities in support of construction as identified in Exhibit D, "Construction Site".

p. Document Control in support of Contractor's construction activities using the existing site systems.

q. Project Controls related to Contractor's Construction and other work activities, including planning and prioritization of Work activities.

r. Contract administration and support services as described in Section 13 below.

s. Transition activities as described in Section 3 below.

### 2.2 Not Included in Contractor's Scope of Work

The following construction-related scope does not form part of the Work:

a. Any Work performed under (1) "Legacy Work Packages" as of the Effective Date (as identified in Table 1 of Exhibit V, "Work Packages") or, (2) "Completed and Voided Work Packages" as of the Effective Date (as identified in Table 2 of Exhibit V);

b. Any Work performed before the Effective Date as part of work pursuant to "In-Progress Work Packages" (as identified in Table 3 of Exhibit V), or;

c. Any work performed or to be performed under Owner-Managed Subcontracts or the management or administration of such Owner-Managed Subcontracts.

## 3. TRANSITION ACTIVITIES

### 3.1 Contractor's Responsibilities

Contractor's responsibilities include:

a. Complete the transition of craft personnel with a target completion date of [***] Business Days after the Effective Date.

b. Complete the transition of field non-manual personnel with a target completion date of [***] Business Days after the Effective Date.

c. Complete the preparation and transition to interim programs, plans, manuals, and procedures for Construction; Quality Assurance; Quality Control; Welding; Environmental, Safety, & Health; Procurement & Subcontracts; Project Controls; Project Administration; and Information Technology with a target completion date of [***] Business Days after the Effective Date.

d. Complete the preparation and transition to full programs, plans, manuals, and procedures for Construction; Quality Assurance; Quality Control; Welding; Environmental, Safety, & Health; Procurement & Subcontracts; Project Controls; Project Administration; and Information Technology with a target completion date of [***] Business Days after the Effective Date.

e. Complete the preparation and transition of construction software tools with a target completion date of [***]Business Days after the Effective Date.

f. Complete the preparation of the program and plan for ASME NA and NPT certifications with a target completion date of [***] Business Days after the Effective Date.

### 3.2 Owners' Responsibilities

Owners' responsibilities include:

a. Ensure all necessary arrangements are in place to allow Contractor to operate under existing programs, plans, manuals, and procedures until completion of Contractor's transition activities identified above.

b. Support Contractor's transition activities identified above.

c. Review Contractor's programs, plans, and procedures, as applicable.

## 4. CONSTRUCTION

### 4.1 Work Packages

The division of responsibility between Owners and Contractor for Work Packages is provided in Table 1 (located on page 7).

### 4.2 Construction Management and Building/Area Management

#### 4.2.1 Contractor's Responsibilities

Contractor's responsibilities include:

a. Manage site-wide construction for the completion of Units 3 and 4, including the containment buildings, shield buildings, auxiliary buildings, annex buildings, diesel generator buildings, radwaste buildings, turbine buildings, balance of plant, and construction support.

b. Manage (and overall authority for) the development and execution of the field non-manual staffing plan, subcontracting plan for Contractor-Managed Subcontracts, labor strategy, construction execution plan, and jobsite work rules.

c. Implement and manage the Contractor's Environmental, Safety, & Health program as described in Section 6 below.

d. Lead interfaces with the building trades including jobsite labor relations and coordination with appropriate business agents.

e. Control jobsite expenditures for labor, construction, materials, and construction services.

**Exhibit A – Scope of Work / Division of Responsibilities**

| Table 1. Work Package Division of Responsibility | |
|---|---|
| **Responsibility** | **Description** |
| **1. Work Package Scoping and Planning** | |
| Owners | • Perform Work Package scoping and planning to support the Construction schedule, with support from Contractor, including:<br>- Define scope<br>- Identify design requirements and ITAAC<br>- Assemble Owners' Issued for Construction Documents (drawings, installation specifications, weld data sheets, etc.), Verification/Inspection Data Sheets, etc.<br>- Evaluate status of Plant Equipment and Materials, prepare material take-offs/material requests for Plant Equipment and Materials, clear material holds, and prepare Material Requisitions to ensure availability of material for Work Package execution.<br>• Prepare Work Package Scoping Document, issue for Contractor review, resolve Contractor's comments, issue final Work Package Scoping Document. |
| Contractor | • Support Work Package scoping and planning performed by Owners.<br>• Review Issued for Construction Documents focusing on constructability, perform constructability walkdowns, resolve comments with Owners.<br>• Review material take-offs, material requests, and Material Requisitions prepared by Owners for Plant Equipment and Materials and provide feedback on missing items, material holds, etc.<br>• Review Work Package Scoping Document prepared by Owners.<br>• Evaluate status of non-permanent plant materials and, as appropriate, prepare Material Requisitions to ensure availability of material for Work Package execution. |
| **2. Work Package Preparation** | |
| Contractor | • Based on the Work Package Scoping Document, prepare Work Package including construction work steps and sequencing, issue for Owners review, resolve Owners' comments, issue final Work Package. |
| Owners | • Review Work Package prepared by Contractor. |
| **3. Work Package Execution** | |
| Contractor | • Manage/control Work Package during installation.<br>• Perform inspections and signoffs in accordance with the requirements in the Work Package (i.e., Field Engineering inspections).<br>• Confirm that all work steps are completed and signed-off in the Work Package. |
| Owners | • Perform any inspections and signoffs identified for Owners in the Work Package.<br>• Provide support to Contractor as requested including review and approval of changes requested to Owners' Issued for Construction Documents. |
| **4. Work Package Closure** | |
| Contractor | • Close Work Package and enter into Owners' records management system. |
| **5. Owners' Oversight and Staffing** | |
| Owners | • Perform Owners' oversight of Contractor's Work Package activities. |
| Owners and Contractor | • Perform joint resource review on a quarterly basis and adjust planning resources based on the mutually agreeable results of the review. |

f. Establish and implement construction policies and procedures as appropriate.

g. Develop craft skills training and any testing as required (Section 4.7 below).

h. Coordinate jobsite activities in support of construction including actions of Contractor's personnel, subcontractors, suppliers, clients, and their representatives.

i. Establish and implement construction schedules, methods, manning charts, and construction material and equipment requirements.

j. Develop plans and establish procedures to support meeting engineering designs and specifications set forth in Owners' Issued for Construction Documents.

k. Establish project field procedures and objectives within policies and procedures as necessitated by site conditions.

**4.2.2 Owners' Responsibilities**

Owners' responsibilities include:

a. Manage (and overall authority for) procurement of Plant Equipment and Materials, modules, and equipment in support of Construction.

b. Commercial administration of Contractor-Managed Subcontracts.

**4.3 Craft and Craft Supervision**

**4.3.1 Contractor's Responsibilities**

Contractor's responsibilities include:

a. Engage craft personnel in the appropriate discipline/trades to execute the planned work.

b. Implement screening to support the hiring of qualified individuals; check qualifications currently held; and provide the appropriate qualification/indoctrination/training to prepare each new employee for work assignment.

c. Review as part of the selection process qualifications and required leadership skills for the assignment of General Foreman/Foreman.

d. Provide craft supervision (superintendents) to lead the craft during field execution of the work with the following responsibilities:

  – Coordinate and interface with Field Engineering, Quality Control, Quality Assurance, Construction Area Managers, and others (as required) to support proper interface for activities that could affect construction.

- Provide leadership and day-to-day direction to support the completion of work activities in accordance with approved Work Packages, procedures, budgets, and schedules.
- Provide resource loading needs by discipline, plan field work based on scheduled activities (manpower, materials, equipment, tools, etc.).
- Communicate applicable plan-of-the day and schedule information to General Foreman.
- Perform constructability reviews.
- Review Work Packages to check required sign offs are up to date with status of work.
- Manage productivity and performance in assigned area, communicate issues preventing/hampering work progress to the Area Manager, and mentor General Foreman and Foreman on the correct manner of work execution and leadership in the field.

#### 4.3.2 Owners' Responsibilities

Owners' responsibilities include:

a. Engage craft labor and craft supervision for any work performed under Owner-Managed Subcontracts.

### 4.4 Quality Control

#### 4.4.1 Contractor's Responsibilities

Contractor's responsibilities include:

a. Provide leadership and direction of the Quality Control organization consistent with Construction provided schedules and priorities.

b. Implement and maintain the Contractor's Quality Control program providing independent verification of safety-related and augmented quality structures, systems, and components (SSCs).

c. Administer the nonconforming item control system.

d. Perform inspections, witness testing activities, and provide surveillance of onsite installations and fabrications.

e. Perform surveillance and inspections of housekeeping and material storage and handling.

f. Perform independent first line inspection of Contractor's work and surveillance of work performed by Subcontractors with an approved Quality Assurance (QA) program.

g. Perform material receiving inspection of safety-related and augmented quality SSCs.

h. Administer the program for control and issue of Measuring & Testing Equipment.

i. Review and approve Work Packages prior to implementation for compliance with the Quality Control program, identification of witness and hold points, and inclusion of proper quality documentation.

j. Perform closure reviews of Work Packages for completion of all required quality verifications.

l. Coordinate daily with Construction Management, Field Supervision, Field Engineering, and Procurement and Subcontracts to provide Quality Control support where needed.

m. Initiate stop work orders for activities not properly controlled in accordance with Contractor's QA Program. Escalate unresolved quality issues to Contractor's Quality Assurance group.

#### 4.4.2 Owners' Responsibilities

Owners' responsibilities include:

a. Identify Owners' witness/hold points and required inspections (see Section 4.1 above for Field Engineering-Work Packages).

b. Overall project Quality Assurance responsibility including oversight, audits, surveillances, etc.

c. Perform Owners' oversight of Contractor's Quality Control activities.

### 4.5 Construction Material, Tools, Equipment, and Consumables

#### 4.5.1 Contractor's Responsibilities

Contractor's responsibilities include:

a. Generate material requests (for Plant Equipment and Materials) and field procurement requests (for non-permanent plant material, consumables) in support of the construction execution schedule as appropriate.

b. Prepare material requisitions (Store Room Requests) to initiate material issuance to Construction.

c. Obtain materials from the warehouse and/or arrange for delivery to designated staging locations.

d. Coordinate and control construction material laydown and/or temporary storage locations.

e. Plan, coordinate, withdraw, control/maintain tools (including measurement & test equipment) and equipment required for construction execution.

f. Manage and operate all large common use Construction Equipment (e.g., cranes, heavy haul equipment, large trucks, etc.) to facilitate construction evolutions (to be managed by the Construction Support Group, see Section 4.6 below).

g. Implement and maintain a preventive maintenance program and asset preservation program, in conjunction with the Owners, and in accordance with Contractor's Quality Assurance Program and the site ASME Certificate Holder's Quality Assurance Program for all Plant Equipment and Materials stored onsite and in offsite warehouses until care, custody, and control has been turned over to the Owners. For ASME Section III items, turnover to the Owners is accomplished upon transition from ASME Section III to ASME Section XI programs.

h. Provide craft supervision and craft personnel to support the preventive maintenance program and asset preservation program until care, custody, and control has been turned over to the Owners.

### 4.5.2 Owners' Responsibilities

Owners' responsibilities include:

a. Generate requisitions for Plant Equipment and Materials.

b. Commercially administer all Owner-Managed Subcontracts for subcontractor supplied material, tools and equipment.

c. Commercially administer all Owner-Managed purchase orders for leased material, tools, and equipment.

d. Payment under all Contractor-Managed Subcontracts.

e. Provide the processes, tools, and personnel to implement the preventive maintenance program and asset preservation program in accordance with Contractor's Quality Assurance Program and the site ASME Certificate Holder's Quality Assurance Program for all Plant Equipment and Materials stored onsite and in offsite warehouses until care, custody, and control has been turned over to the Owners.

f. Establish, implement, and maintain the preventive maintenance program and asset preservation program for all Plant Equipment and Materials after care, custody, and control has been turned over to the Owners.

g. Provide Construction Equipment in good working condition.

## 4.6 Construction Support and Fabrication

### 4.6.1 Contractor's Responsibilities

Contractor's responsibilities include:

a. Manage all construction support resources and facilities including cranes and other common use Construction equipment, survey services, scaffold, construction support facilities, and the batch plant.

b. Except for Owner-Managed Subcontractors, manage all fabrication facilities (fabrication shops, module assembly building, satellite fabrication areas); provide craft and supervision and/or manage Contractor-Managed fabrication subcontractors, as applicable.

c. Determine and manage priorities associated with the deployment of construction support resources.

d. Implement and maintain a preventive maintenance program and asset preservation program, in conjunction with the Owners, and in accordance with Contractor's Quality Assurance Program and the site ASME Certificate Holder's Quality Assurance Program for all Plant Equipment and Materials stored onsite and in offsite warehouses until care, custody, and control has been turned over to the Owners. For ASME Section III items, turnover to the Owners is accomplished upon transition from ASME Section III to ASME Section XI programs.

e. Provide craft supervision and craft personnel to support the preventive maintenance program and asset preservation program until care, custody, and control has been turned over to the Owners.

### 4.6.2 Owners' Responsibilities

Owners' responsibilities include:

a. All work performed under Owner-Managed Subcontracts.

b. Provide the processes, tools, and personnel to implement the preventive maintenance program and asset preservation program in accordance with Contractor's Quality Assurance Program and the site ASME Certificate Holder's Quality Assurance Program for all Plant Equipment and Materials stored onsite and in offsite warehouses until care, custody, and control has been turned over to the Owners.

c. Establish, implement, and maintain the preventive maintenance program and asset preservation program for all Plant Equipment and Materials after care, custody, and control has been turned over to the Owners.

d. Manage facilities identified as Owners' scope in Exhibit D, "Construction Site".

e. Provision of construction utilities (power, water, etc.).

### 4.7 Construction Training

#### 4.7.1 Contractor's Responsibilities

Contractor's responsibilities include:

a. Perform all craft indoctrination training on Contractor's Environmental, Safety, and Health processes.

b. Perform all craft skill/proficiency training.

c. Coordinate in-processing needs and timing with Owner.

#### 4.7.2 Owners' Responsibilities

Owners' responsibilities include:

a. Perform all in-processing and site security, including fitness for duty.

b. Perform all Owner required training for access to the Vogtle site.

### 4.8 Construction Completion

#### 4.8.1 Contractor's Responsibilities

Contractor's responsibilities include:

a. Establish and manage a Construction Completion Group which will facilitate and coordinate completion of physical construction and construction testing required for turnover from Construction to Owner Startup/Commissioning. Contractor's Construction Contractor's construction testing responsibilities are identified in Table 2 of Exhibit G, "Mechanical Completion."

b. Oversee turnover of systems/subsystems/components from Construction to Owners' Startup/Commissioning.

c. Serve as the interface between Scheduling, Design Engineering, Construction, Planning, Closeout, and other organizations.

#### 4.8.2 Owners' Responsibilities

Owners' responsibilities include:

a. Coordinate with Contractor's Construction Completion Group to support turnover of systems/subsystems/components from Construction to Owners' Startup/Commissioning.

b. Review and closeout of "Legacy Work Packages."

c. Perform Construction Testing identified as Owners' responsibility in Table 2 of Exhibit G, "Mechanical Completion."

### 4.9 Other Construction Work Activities

#### 4.9.1 Contractor's Responsibilities

Contractor's responsibilities include:

a. Manage the construction scope of Contractor-Managed Subcontracts using Contractor Subcontract Technical Representatives as described in Section 8 below.

#### 4.9.2 Owners' Responsibilities

## 5. QUALITY

None.

### 5.1 Contractor's Responsibilities

Contractor's responsibilities include:

a. Implement Contractor's Nuclear QA program to cover Contractor's Construction activities integrated with Owners' overall QA program to the extent possible.

b. Develop and maintain a Contractor project quality oversight plan to facilitate QA oversight.

c. Plan and conduct QA audits and surveillances of Contractor's Construction activities to review effectiveness and implementation of Contractor's QA Program. Participate in joint Owner-Contractor audits where possible.

d. Identify quality problems, initiate documented action leading to solutions, and review implementation of solutions.

e. Qualify and certify Contractor's QA lead auditors, auditors, and technical specialists participating in Contractor's QA audit and surveillance program.

f. Upon approval to proceed, acquire and maintain Vogtle Units 3 & 4 site extensions of Contractor's corporate ASME NA and NPT-Certificates of Authorization.

g. Upon approval to proceed, obtain Authorized Inspection Agency services for ASME Section III-related activities.

h. Qualify and certify Contractor's Supplier Quality lead auditors, auditors, and inspection personnel participating in Contractor's supplier qualification activities.

i. Implement Owners' Corrective Action Program (CAP) for Contractor's Construction activities and incorporate Owners' CAP into the Contractor's Quality program.

j. Implement Contractor's People-Based Quality Program.

k. Assist Owners' QA with regulatory interface, as required.

l. Take stop work action when warranted.

m. Incorporate Owners' processes and procedures into Contractor's QA program as directed by Owners for common site-wide project work processes (e.g., CAP, as noted above; control of site-wide procedures; records retention using Owners' document management system; and others at Owners' discretion).

### 5.2 Owners' Responsibilities

Owners' responsibilities include:

a. Overall project QA responsibility including oversight, audits, surveillances, etc.

b. Qualification of Contractor as an approved supplier to Owners.

c. Regulatory interface.

d. Overall project CAP for site issue management.

e. Notify Contractor of quality issues identified by Owners related to Contractor's Construction activities.

f. Delegation of work to Contractor for performance under Contractor's QA program.

g. Identification of other common, site-wide Owner processes and procedures for incorporation into Contractor's QA program.

## 6. ENVIRONMENTAL, SAFETY, & HEALTH

### 6.1 Contractor's Responsibilities

Contractor's responsibilities include:

a. Implement an Environmental, Safety, & Health (ES&H) program, including a site-wide Safety program, which will include plans/procedures for safe, healthy, and environmentally sound work execution.

b. Manage ES&H rewards and recognition program.

c. Manage medical services subcontractor and medical facilities (onsite and offsite).

d. Manage work related illness/injuries of Contractor personnel, craft personnel, and Contractor-Managed Subcontractor personnel.

e. Manage Emergency Response Team (full-time subcontractor and/or volunteer craft supervision/nonmanual/craft team) including training and equipment purchase and upkeep.

f. Monitor and audit safety and health vendors and subcontractors.

g. Perform assessments and audits.

h. Perform ES&H related regulatory, leadership, and orientation training.

i. Perform Industrial Hygiene services, subcontract specialty services as appropriate, and monitor subcontractor adherence to industrial hygiene scope-specific procedure(s).

j. Coordinate with the Owners' Environmental program for the performance of delegated environmental field compliance inspections, maintenance of environmental compliance logs (e.g., waste, spill/release, combustion equipment), sampling efforts (air, water, waste), safety data sheet (SDS) review and control, management of waste generated by the Contractor and Contractor subcontractors, and coordinate data and reports necessary for regulatory reporting by the Owners per Table 2 (located on page 25).

k. Collaborate with the Owners concerning revisions to the Environmental plans and procedures.

l. Prepare weekly and monthly ES&H statistical reports.

m. Manage aspects of the work permit process (e.g., confined space) and audit permits managed by Construction.

n. Facilitate and manage the ES&H incident investigation process.

o. Facilitate safety committees, including the People Based Safety team.

p. Facilitate Construction/ES&H activity planning meetings.

q. Facilitate and manage open ES&H action reports/logs (input to closure).

r. Coordinate daily with Construction and Procurement and Subcontracts to provide ES&H support where needed.

s. Perform ES&H in-processing and any additional ES&H training as appropriate.

### 6.2 Owners' Responsibilities

Owners' responsibilities include:

a. Manage the Owner Controlled Insurance Program (OCIP).

b. Manage Environmental permitting, compliance, and related activities and perform Owners' environmental compliance activities identified in Table 2.

c. Manage work related injury/illnesses of Owners and Owner-Managed Subcontractors.

d. Support Occupational Health Plan implementation including coordination with OCIP, providing wellness resources, and providing lessons learned.

e. Review safety weekly and monthly statistical reports.

f. Monitor and audit Owner-Managed Subcontractors for compliance.

g. Participate, as appropriate, in Emergency Response team (e.g., office wardens, member of Incident Management Team, etc.).

h. Participate in ES&H activity planning meetings.

i. Participate, as appropriate, in safety committees, incident investigations, and rewards and recognition program.

j. Manage environmental permits and matrix, monitor and inspect environmental controls as appropriate.

k. Implement an ES&H program for areas and facilities controlled by the Owners and Owner-Managed Subcontractors as identified in Exhibit D, "Construction Site".

l. Perform Owners' oversight of Contractor's ES&H activities.

## 7. PROJECT CONTROLS

### 7.1 Contractor's Responsibilities

Contractor's responsibilities include:

a. Develop and manage Level 3 construction cost, schedule, and performance baselines which is part of the Project Integrated Level 3 Schedule.

b. Resource load the Level 3 Construction activities with craft resources (jobhours) to establish the Construction earnings plan.

c. Develop staffing plans for craft and field non-manual personnel based on schedule and performance baselines for Owner approval.

d. Develop commodity installation curves based on Level 2 schedule requirements and density restrictions for Owner approval.

e. Provide input to the Owners to establish performance measurement tools including rules of credit.

f. Input actual installation progress into EcoSys Quantity Unit Rate Report (QURR) performance measurement tools.

g. Audit timesheets for accuracy and make corrections where necessary.

h. Develop, manage, and maintain the Level 3 Project Schedule for construction activities in accordance with mutually-agreed Owners' construction scheduling guidelines.

i. Develop, manage, and maintain lower level schedules for construction activities as needed.

j. Incorporate schedules for Contractor-Managed Subcontracts into the Level 3 construction Project Schedule.

k. Identify construction need dates in the Level 3 construction Project Schedule for Owners' scope items including engineering, licensing, supply of Plant Equipment and Materials, etc.

l. Work with Owners to identify Work Package schedule information in the Level 3 construction Project Schedule as needed to support Work Package development and system turnover.

m. Resolve impacts in Level 3 construction critical paths and update Level 3 schedule.

n. Produce weekly and monthly reports and metrics for progress and performance including:

- Scorecard reflecting weekly production, productivity, and schedule performance at the unit/building/commodity level of detail.
- QURR reflecting detailed production and productivity at the cost account level.
- Provide input to Owners' bulk commodity curves installed versus plan.
- Provide input to Owners' schedule variance reporting.
- Provide input to Owners' schedule adherence reporting.
- Absenteeism and attrition.

o. Produce metrics for indirect craft versus budgeted staffing plans.

p. Produce metrics for non-manual actual versus budgeted plan.

q. Provide cost tracking for Construction Work including direct and indirect craft and field non-manual personnel.

r. Maintain a cost & commitment report for procurements and Contractor-Managed Subcontracts.

s. Forecast monthly expenditures.

t. Perform material/commodity quantification.

u. Recommend reporting requirements for Contractor-Managed Subcontracts for Owners' approval.

v. Assist in establishing scope, manhour, and cost estimates for Contractor-Managed Subcontracts.

w. Propose criteria for calculating construction percent complete for Owners' approval.

x. Identify construction trends and change management issues, and participate in the Owners' change control program.

y. Provide input to the Owner-maintained construction risk register.

z. Provide information to assist Owners in responding to requests from the Public Service Commission.

### 7.2 Owners' Responsibilities

Owners' responsibilities include:

a. Oversee overall project cost and schedule reporting.

b. Work with Contractor to develop mutually-agreeable construction scheduling guidelines.

c. Develop and maintain scheduling guidelines for other functions (e.g., engineering, licensing, etc.).

d. Review overall project controls guidelines for effectiveness and completeness.

e. Ownership of the integration of the Level 1, 2, and 3 Project Schedule.

f. Develop, manage, and maintain the Level 1 and Level 2 Project Schedule.

g. Develop, manage, and maintain the Level 3 Project Schedule for non-construction activities (e.g., engineering, licensing, ITAAC, startup, etc.).

h. Develop and issue 8-week lookahead Project Schedule with input from Contractor for the construction schedule.

i. Analyze impacts to Project Schedule from construction Level 3.

j. Review changes to the overall project cost and schedule.

k. Audit performance measurement reporting for accuracy.

l. Review risk and change process and register.

m. Prepare reports and respond to requests for information from the Public Service Commission.

n. Produce project reports and cost and schedule metrics including variance analysis, risk analysis, float management, schedule fidelity, earned value, and critical path.

o. Establish performance measurement tools with input from the Contractor and other functions on rules of credit.

p. Develop and maintain performance measurement reporting (cost and schedule).

## 8. FIELD PROCUREMENT AND SUBCONTRACTS

### 8.1 Contractor's Responsibilities

Contractor's responsibilities include:

a. Provide leadership and direction of the Field Procurement and Subcontracts organization consistent with Construction provided schedules and priorities.

b. Support the Subcontract Scope Alignment Process as a joint Contractor and Owner effort (see Article 3.2 and Exhibit E, "Subcontract Alignment Process and Managed Subcontracts").

c. Manage Contractor-Managed Subcontracts using Owners' procedures, processes, and tools and as appropriate obtain Owners' approval at pre-agreed levels for change orders.

d. For agreed to subcontracts, provide invoice review of Contractor-Managed Subcontracts or payment of Contractor issued Field Procurements.

e. Manage Plant Equipment and Materials both onsite and offsite, including receipt and inspection, warehouse/laydown yard management, material coordination/issuance; identify and segregate startup and operational spares and notify Owners for transfer.

f. Implement and maintain the Material Coordination Management/Process including setting priorities for purchases and field deliveries, coordinating with warehouse and Construction personnel to resolve material delay/issues, using the project schedule to identify material requirements and potential restraints, elevating critical issues to Construction and Project Management, and overseeing material staging areas within the construction area(s).

g. Implement and maintain a preventive maintenance program and asset preservation program, in conjunction with the Owners, and in accordance with Contractor's Quality Assurance Program and the site ASME Certificate Holder's Quality Assurance Program for all Plant Equipment and Materials stored onsite and in offsite warehouses until care, custody, and control has been turned over to the Owners. For ASME Section III items, turnover to the Owners is accomplished upon transition from ASME Section III to ASME Section XI programs.

h. Provide craft supervision and craft personnel to support the preventive maintenance program and asset preservation program until care, custody, and control has been turned over to the Owners.

### 8.2 Owners' Responsibilities

Owners' responsibilities include:

a. Procure all Plant Equipment and Materials.

b. Manage all Owner-Managed Subcontracts.

c. Support the Subcontract Scope Alignment Process as a joint Contractor and Owner effort (see Article 3.2 and Exhibit E, "Subcontract Alignment Process and Managed Subcontracts").

d. Payment under all Contractor-Managed Subcontracts.

e. Provide the processes, tools, and personnel to implement the preventive maintenance program and asset preservation program in accordance with Contractor's Quality Assurance Program and the site ASME Certificate Holder's Quality Assurance Program for all Plant Equipment and Materials stored onsite and in offsite warehouses until care, custody, and control has been turned over to the Owners.

f. Establish, implement, and maintain the preventive maintenance program and asset preservation program for all Plant Equipment and Materials after care, custody, and control has been turned over to the Owners.

g. Perform Owners' oversight of Contractor's Procurement and Subcontracts activities.

## 9. ENGINEERING

### 9.1 Contractor's Responsibilities

a. Review Issued for Construction documents received from Owners for constructability; seek to resolve constructability issues with Owners.

### 9.2 Owners' Responsibilities

Owners' responsibilities include:

a. Perform all Design Engineering and Resident Engineering.

b. Provide Issued for Construction Documents to Contractor.

## 10. PROJECT ADMINISTRATION

### 10.1 Contractor's Responsibilities

Contractor's responsibilities include:

a. Provide leadership and manage Work Package configuration including daily maintenance through final closeout to Owners consistent with the requirements of the Contractor's quality program.

b. Capture and manage records for Contractor's work activities through turnover to Owners using Owners' document management system, and related Owner processes and procedures incorporated into Contractor's QA program.

c. Coordinate and issue training records for all Contractor field non-manual personnel, manage completed training records and turnover to Owners.

### 10.2 Owners' Responsibilities

Owners' responsibilities include:

a. Maintain overall records management software to be used by the project.

b. Manage all records for Owners' work activities.

c. Perform Owners' oversight of Contractor's Document Control activities.

## 11. HUMAN RESOURCES

### 11.1 Contractor's Responsibilities

Contractor's responsibilities include:

a. Manage the Human Resources function.

b. Develop and maintain the Human Resources program and implementing policies and procedures.

c. Produce weekly and monthly metrics on standard Human Resources performance and measures such as retention, involuntary terminations, headcount, and time-to-fill positions.

d. Develop and manage a recruitment plan.

e. Provide on-boarding support including relocation, E-verify, and project security requirements.

f. Facilitate employee relations including the investigation and resolution of employee relations issues.

g. As requested by Owners, support Owners' investigations of employee concerns that are raised through the Owners' Employee Concerns program and fall within Contractor's scope of work.

h. Develop a discipline/termination policy for manual and non-manual employees to review the consistency of disciplinary actions which aligns with the policies and regulatory requirements of the Owners' program.

i. Identify programs and tools to develop, attract, and retain project talent.

j. Respond to regulatory agency requests and audits.

k. Develop a project Affirmative Action Plan and meet annual reporting requirements.

l. Provide new hire orientation to new project hires and transfers.

m. Coordinate a performance management program that includes goal setting, performance feedback, and compensation planning.

**11.2 Owners' Responsibilities**

Owners' responsibilities include:

a. Establish and maintain an Employee Concerns program.

b. Collaborate on the joint resolution of Human Resources issues that cut across company lines.

c. Notify Contractor of issues raised through the Employee Concerns program associated with Contractor's scope of work.

d. Perform Owners' oversight of Contractor's Human Resources activities.

## 12. INFORMATION, SYSTEMS, & TECHNOLOGY

### 12.1 Contractor's Responsibilities

Contractor's responsibilities include:

a. Implement and maintain Contractor's software tools used in support of the project.

b. Install and maintain Contractor's computers and related hardware at the site.

### 12.2 Owners' Responsibilities

Owners' responsibilities include:

a. Provide computers to Contractor personnel and continued access to the site software tools.

b. Provide Internet access for Contractor personnel to access Contractor's software tools.

c. Provide desk phones.

d. Provide printing and plotting hardware.

## 13. CONTRACT ADMINISTRATION AND SUPPORT SERVICES

### 13.1 Contractor's Responsibilities

Contractor's responsibilities include:

a. Provide Contractor's point of contact for Agreement administration and support Owners' project leadership.

b. Administer the Agreement with Owners.

c. Prepare and submit reports to Owners as required by the Agreement.

d. Prepare and submit invoices to Owners.

### 13.2 Owners' Responsibilities

Owners' responsibilities include:

a. Provide Owners' point of contact for Agreement administration.

b. Administer the Agreement with Contractor.

**Exhibit A – Scope of Work / Division of Responsibilities**

| Table 2. Environmental Compliance Division of Responsibility (Notes 1, 2) | | | | |
|---|---|---|---|---|
| **Title** | **Purpose** | **Owners Responsibility** | **Contractor Responsibility** | **Agency/Frequency/Dates** |
| | | | | |
| **1. ENVIRONMENTAL PROGRAM MANAGEMENT** | | | | |
| Environmental Management Plan | The environmental management plan describes the environmental program implementation strategy. | Primary | Support | Initial update upon contract execution and as needed thereafter |
| ND-EV-VNP-012 (Environmental Governance and Oversight of Construction Activities) | This document outlines the governance related to the Owners' oversight process to ensure the environmental program is implemented in compliance with the existing permits, rules and regulations. | Primary | None | |
| Program Specific Governance | Procedures and/or work instructions providing clear, concise instructions to the construction organization. Currently procedures are in place which may not be available for project use. | Primary | Support | Initial update upon contract execution and as needed thereafter |
| | | | | |
| **1.1 Title V Air Permit # 4911-33-0030-V-03-1** | | | | |
| Emission Source Installation Notification | EPD Notification for startup of each piece of permanent equipment regulated by Owners' Title V Air Permit # 4911-33-0030-V-03-1.7. Submitted within 120 days of startup. | Support | Primary | Upon installation of permitted source |
| Ultra-Low Sulfur Fuel Certifications from fuel suppliers *for Owners Title V* Air Permit # 4911-33-0030-V-03-1 *Permit* | Report provided by the fuel supplier(s) on company letterhead certifying fuel provided to the project contains less than 15ppm sulfur content. Certification is a permit condition requirement. Send report to Owners. | Support | Primary | Semi-Annual (Jan10 & Jul 10) |
| Equipment Preservation Check Record (EPCR) for Owners' Title V Air Permit # 4911-33-0030-V-03-1 [Preventative Maintenance activities on permanent plant equipment] | Inspection and Test of permanent emission sources. For certified engines, startup performance testing is not required. The Permittee shall not discharge or cause the discharge into the atmosphere from any gases which exhibit opacity equal to or greater than 40 percent. The PM Group maintains the engine & records the run time hours in log books. As each piece of equipment is added, coordination will be required to ensure compliance. | Support | Primary | Upon request |

**Exhibit A – Scope of Work / Division of Responsibilities**

| Table 2. Environmental Compliance Division of Responsibility (Notes 1, 2) | | | | |
|---|---|---|---|---|
| **Title** | **Purpose** | **Owners Responsibility** | **Contractor Responsibility** | **Agency/Frequency/Dates** |
| | | | | |
| Title V Emissions Inventory for Owners Title V Air Permit # 4911-33-0030-V-03-1 | Log for every piece of permanent equipment regulated by Owners' Title V Air Permit # 4911-33-0030-V-03-1. The PM Group maintains the engine & records the run time hours in log books. As each piece of equipment is added, coordination will be required to ensure compliance. Submit monthly to VEGP 1&2 Environmental Specialist. | Support | Primary | Upon Install / Performance Testing |
| Fuel Burning Equipment | The Permittee shall not cause, let, suffer, permit, or allow the emission from any fuel burning emissions the opacity of which is equal to or greater than twenty (20) percent except for one six-minute period per hour of not more than twenty-seven (27) percent opacity. [391-31-.02(2) (d)] | Support | Primary | Upon Install / Performance Testing |
| Visible Emissions | The Permittee shall not cause, let, suffer, permit or allow emissions from any source the opacity of which is equal to or greater than forty (40) percent opacity (6-minute average). [391-3-1-.02(2)(b )1] | Support | Primary | As Needed |
| | | | | |
| | | | | |
| **1.2 SIP Air Permit # 1629-033-0039-S-02-0** | | | | |
| Visible Emissions | The Permittee shall not cause, let, suffer, permit or allow emissions from any source the opacity of which is equal to or greater than forty (40) percent opacity (6-minute average). [391-3-1-.02(2)(b )1] | Support | Primary | As Need/Upon Install |
| Concrete Crusher Daily Operations Log Checklist Inspection if on-site for | Daily operations checklist inspection of concrete crushers in accordance with Permit Conditions (as needed – during concrete crushing activities) | Support | Primary | Daily Log |
| Construction Air Quality Permit Emissions Calculations | Tracking permit conditions and limitations (see Equipment run hour report and the NOx emissions calculation spreadsheet). Monthly NOx emission limit is 8.33 tons. | Support | Primary | Monthly, Permit Record & Georgia EPD (upon request) |
| Concrete Batch Plant Compliance Record Keeping | Ensure regulatory obligations related to the Concrete Batch Plant records are being maintained in accordance with Permit Sections 4.2 and 5.4 These are records are prepared and maintained by the Concrete Batch Plant. | Support | Primary | Monthly, Permit Record & Georgia EPD (upon request) |

**Exhibit A – Scope of Work / Division of Responsibilities**

| Table 2. Environmental Compliance Division of Responsibility (Notes 1, 2) | | | | |
|---|---|---|---|---|
| **Title** | **Purpose** | **Owners Responsibility** | **Contractor Responsibility** | **Agency/Frequency/Dates** |
| | | | | |
| Concrete Batch Plant Operations Report ( *this report is a normal monthly production report & is not a separate report for environmental reporting purposes)* | Tracking of Batch Plant Operations (Batch Plant Manager emails this report monthly). | Support | Primary | Monthly |
| Construction Air Quality Permit Quarterly Report | Permit Condition 7.2 requires a quarterly report summarizing engine runtimes, concrete throughput and NOx emissions. | Support | Primary | Quarterly (30th) |
| Ultra-Low Sulfur Fuel Certifications from fuel suppliers | Report provided by the fuel supplier(s) on company letterhead certifying fuel provided to the project contains less than 15ppm sulfur content. Certification is a permit condition requirement. Send report to Owners. | Support | Primary | Semi-Annual (Jan10 & Jul 10) |
| Annual Air Emissions Fee | Air emission fees required for the operation of stationary construction equipment. Owners pay the required fees. | Support | Primary | Annual (Sept 1st) |
| Concrete Crusher Performance Test for *SIP* | Permit Condition 6.1 requires a performance test conducted in accordance with USEPA Method 9 for concrete crushing equipment. (test and submit to EPD if using different crusher) | Support | Primary | Upon Install / Performance Testing |
| | | | | |
| | | | | |
| **1.3 General Air Regulatory Obligations** | | | | |
| Greenhouse Gas Report | Greenhouse gas reporting required when threshold of 25,000 tons of GHG is exceeded annually. Send the project's estimated GHG emissions to Owners. (Owners have .xls) | Support | Primary | Annual (Jan 10) |
| CFC Equipment Registrations and Inventory (40 CFR 82 – Protection of Stratospheric Ozone) | Document CFC equipment registrations, employee certifications, equipment inventories, and maintenance and handling records, provide Owners with list of equipment during building turnover. | Support | Primary | Each |
| SF6 Reporting | SF6 is a HAP ->Track -> used for fire suppression in instrument panels in turbine bldg. Provide annual inventory for Owners. | Support | Primary | Annual |

**Exhibit A – Scope of Work / Division of Responsibilities**

| Table 2. Environmental Compliance Division of Responsibility (Notes 1, 2) | | | | |
|---|---|---|---|---|
| **Title** | **Purpose** | **Owners Responsibility** | **Contractor Responsibility** | **Agency/Frequency/Dates** |
| | | | | |
| **2. WATER QUALITY COMPLIANCE** | | | | |
| **2.1 General Permit No. GAR 100001 - Stormwater Discharges Associated with Construction Activity (19 Active Owners' NOIs)** | | | | |
| Construction Stormwater General Permit Notices of Intent/Notices of Termination | Prepare, maintain and submit the per the Construction Storm Water General Permit. | Primary | Support | As needed. Next major submittal will be the renewal of open NOIs upon issuance of the new general permit. |
| Erosion, Sediment Pollution Control and Prevention Plans | Prepare, maintain and revise the ES&PC Plan per the Construction Storm Water General Permit. This includes preparation of redline plans and periodic design professional review for changes to hydraulic components. | Primary | Support (prepare redlines) | Maintain Redlines following inspections. Submit ES&PC Plan as required by the permit. |
| Turbidity Sampling | Collect storm water samples per the permit requirements if a qualifying rain event occurs. Rainfall shall exceed 0.5 inches between the hours of 8 am to 5 pm for the event to be considered a qualifying event. Owners' Site Personnel perform Turbidity analysis. | Primary (shared) | Primary (shared) | Collect samples as required during each qualifying rain event. |
| Erosion & Sediment Control Inspections | Inspections per the Construction Storm Water General Permit. (CSI 3-20 and HB Sequence Inspection Program) | Support | Primary | Daily, Weekly, Monthly, and End-of-Storm Events |
| Daily Rainfall Measurements | Record & document daily rainfall per construction storm water permit requirements. (Weather Station & Software) | Support | Primary | Daily |
| Consolidated (includes active NOIs only) Monthly Construction Storm Water Monitoring Report | Prepare and submit the required monthly report if a qualifying rain event occurred during the month. If a qualifying event did not occur, documentation shall be placed in the administrative record. | Support | Primary | Monthly (per event) |
| | | | | |
| | | | | |
| **2.2 Owners' Permit to Operate Potable Water System PG 0330056** | | | | |
| Vogtle Units 3 & 4 Potable Water System (Temporary and Permanent) | Potable Water System tracking summary for water usage and free chlorine in accordance with Permit. | Primary | None | Daily |
| Lead and Copper Sampling and VOC | Lead and Copper sampling per Georgia Rule for Safe | Primary | None | Annual |

**Exhibit A – Scope of Work / Division of Responsibilities**

| Table 2. Environmental Compliance Division of Responsibility (Notes 1, 2) | | | | |
|---|---|---|---|---|
| **Title** | **Purpose** | **Owners Responsibility** | **Contractor Responsibility** | **Agency/Frequency/Dates** |
| Sampling. | Drinking Water. | | | |
| Total Coliform Sampling. | Coliform sampling per Georgia Rule for Safe Drinking Water. | Primary | None | Monthly |
| TTHM / HAA5 Sampling | TTHM / HAA5 sampling per Georgia Rule for Safe Drinking Water. | Primary | None | Annual |
| Nitrate and Nitrite Sampling | Nitrate and Nitrite sampling per Georgia Rule for Safe Drinking Water. | Primary | None | Annual |
| Potable Waterline Disinfection | Water Line Repairs/New potable water line installations require disinfection and recording in accordance with AWWA standards. Owners will operate and maintain lines within the Auxiliary Pump house. Lines outside the Auxiliary Pump house are the responsibility of Contractor. | Support | Primary | Each |
| Back Flow Preventer Testing | Annual requirement to test back flow preventers on an annual basis. Currently there are 16 backflow preventers that were tested in 2016. Additional backflow preventers that require testing are present at facilities operated by Owners and will be tested under separate contract by the Owners' Maintenance organization. | Primary | Support | Annual |
| | | | | |
| | | | | |
| **2.3 Owners' Permit to Withdraw Groundwater # 017-003 (MU3 and MU4)** | | | | |
| Groundwater Withdrawal from Multiple Aquifers | Support Owners' Ops Readiness collection of data for Permit# -017-003. | Primary | None | Daily & Monthly |
| Measure Water Levels | Vogtle 1&2 Environmental Specialist coordinates with Vogtle 3&4 Chemistry during the performance of drawdown tests, and the collection of raw water samples under Permit # 017-003. Measure the static and pumping levels in each aquifer utilized and the date the water levels were measured. (391-3-2-.08) | Primary | None | Semi-Annual |
| Temperature and Specific Conductance Monitoring Owners' Permit to | Vogtle 1&2 Environmental Specialist coordinates with Vogtle 3&4 Chemistry during the performance of | Primary | None | Annual |

| Table 2. Environmental Compliance Division of Responsibility (Notes 1, 2) | | | | |
|---|---|---|---|---|
| **Title** | **Purpose** | **Owners Responsibility** | **Contractor Responsibility** | **Agency/Frequency/Dates** |
| Groundwater Withdrawal Permit Makeup Wells (MU 3 and MU 4) | drawdown tests, and the collection of raw water samples under Permit # 017-003. | | | |
| | | | | |
| **2.4 Dewatering Wells – Owners' Permit to Withdraw Groundwater # 017-006** | | | | |
| Groundwater Withdrawal from Multiple Aquifers | Provide groundwater withdrawal totals | Support | Primary | Daily & Monthly |
| Dewatering Permit - Temperature and Conductivity Sampling | Annually sample and analyze one raw water sample for Temperature and Specific Conductance Conductivity sample for every five permitted wells. | Support | Primary | Annual |
| | | | | |
| | | | | |
| **2.5 Concrete Batch Plant Permit NPDES #GA0039276** | | | | |
| NPDES Discharge Monitoring Report | Provide a summary of waste water discharges under the NPDES Wastewater Discharge Permit for the Batch Plant Facility. The facility has never had a discharge. Water is used for dust suppression by Morgan. Contingency frac tanks are in place for water storage. | Support | Primary | Monthly |
| Approved Water Containers for Beneficial Reuse | Beneficial reuse of wastewater is authorized by Georgia EPD. This Form provides a list of containers that are authorized to distribute wastewater for beneficial reuse. | Support | Primary | Each |
| Beneficial Reuse Water Log | Provides a log of beneficially reused wastewater. | Support | Primary | Each |
| | | | | |
| | | | | |
| **2.6 Vogtle 3 & 4 Industrial Permit NPDES #GA0039420** | | | | |
| NPDES Discharge Monitoring Report | Provide a summary of waste water discharges under the NPDES Wastewater Discharge Permit. | Support | Primary | Monthly |
| Requirements Applicable to Cooling Water Intake Structures for New Facilities Under 316(b) | There permitee will demonstrate compliance with 316(b) through monitoring and reporting in accordance with Parts 125.87 and 125.88 of the rule. | Support | Primary | As required with annual reporting |

| Table 2. Environmental Compliance Division of Responsibility (Notes 1, 2) | | | | |
|---|---|---|---|---|
| **Title** | **Purpose** | **Owners Responsibility** | **Contractor Responsibility** | **Agency/Frequency/Dates** |
| | | | | |
| CORMIX Mixing Zone Model (Part III A. Special Requirements 13) | The permittee shall perform an instream temperature study in the vicinity of outfall number 001 to demonstrate the results of the CORMIX mixing zone model with the first two years of operation of Vogtle Unit 4 and while all four units (Vogtle 1-4) are operational. | Primary | None | One Event |
| Support Chemistry and ITP during start-up to ensure compliance samples are collected as required. | Provide peer review support and coordinate start up sampling in accordance with Procedure B-ADM-PLMC-012. | Primary | None | As Needed Per System |
| | | | | |
| **2.7 Vogtle 3 & 4 Surface Water Withdrawal Permit #017-0191-11** | | | | |
| Monitoring Report | Provide a summary of water withdrawals under the Permit. | Primary | None | Monthly |
| Dissolved Oxygen Conditions | The permittee agrees to cause the construction and installation of an oxygen injection system, such as a Speece Cone, capable of injecting up 4,000 pounds of oxygen per day. | Primary | None | System Operational by Unit 3 COD, injection performed between April 15 and November 15 |
| | | | | |
| | | | | |
| **2.8 General Water Quality Data Collection** | | | | |
| Storm Water No Exposure Exclusion Certification (NEE). Storm Water No Exposure Exclusion Certification - Waynesboro, GA Warehouse | Ensure materials and activities are not exposed to storm water run-off according to the NEE. | Support | Primary | Quarterly |
| Oil Water Separator Waste Samples (Oil and Grease) | Collect sample from discharge line connected to the Sanitary Sewer to ensure compliance with Vogtle 1&2 NDPES Permit Requirements. | Support | Primary | Semiannual |
| Sanitary Sewer Flow Rates | Measure flow at the 500A outfall to facilitate notification to the Vogtle 3&4 Chemistry Team when flow exceeds 20,000 gallons per day. | Support | Primary | Daily |

## Exhibit A – Scope of Work / Division of Responsibilities

| Table 2. Environmental Compliance Division of Responsibility (Notes 1, 2) | | | | |
|---|---|---|---|---|
| **Title** | **Purpose** | **Owners Responsibility** | **Contractor Responsibility** | **Agency/Frequency/Dates** |
| | | | | |
| | | | | |
| **3. SPILL PREVENTION CONTROL & COUNTERMEASURES (SPCC)** | | | | |
| SPCC Plan (Revisions / Updates) | Site wide plan for the implementation of 40 CFR 112. | Primary (shared) | Primary (shared) | Initial Revision following transition will be prepared by Owners. Revise and Certify SPCC Plan within 6 months of first technical change. |
| Spill Response/Chemical Spill / Release Reports | Clean up and Report all chemical spills / releases per SPCC plan requirements. | Support | Primary | Each Spill / Release |
| Agency Notification Spill Report Form | Report chemical spills / releases that exceed reportable quantities requiring regulatory agency notification per the SPCC Plan / 40 CFR 112 regulations. | Support | Primary | Each |
| Weekly SPCC Facility Inspection | Utilized during routine SPCC facility inspections per SPCC Plan requirements. | Support | Primary | Weekly |
| Annual SPCC Facility Inspection | Utilized during annual SPCC facility inspections per SPCC Plan requirements. | Support | Primary | Annual |
| Spill Response Equipment Inventory | Utilized to ensure that the minimum required spill equipment and spill kits are maintained in-stock on the project site per SPCC Plan requirements. | Support | Primary | Weekly |
| Secondary Containment or Diked Area Drainage Form | Completed anytime a secondary containment or diked area is drained to an area that has access to an open watercourse. | Support | Primary | Each Event |
| SPCC Training | Train Oil Handling Personnel at least once per year per the SPCC Plan and OPA/SPCC regulations in 40 CFR 112 | Support | Primary | Annual |
| | | | | |
| **4. WASTE MANAGEMENT COMPLIANCE** | | | | |
| Weekly Universal Waste Inspections. | Provide record of Universal Waste collection area inspections. | Support | Primary | Weekly |

**Exhibit A – Scope of Work / Division of Responsibilities**

| Table 2. Environmental Compliance Division of Responsibility (Notes 1, 2) | | | | |
|---|---|---|---|---|
| **Title** | **Purpose** | **Owners Responsibility** | **Contractor Responsibility** | **Agency/Frequency/Dates** |
| | | | | |
| Weekly Satellite Accumulation Area Inspections. Owners' USEPA Hazardous Waste Generator ID# GAR000075085 . | Provide record of Satellite Accumulation Area inspections. | Support | Primary | Weekly |
| Weekly 90/270 Day Area Hazardous Waste Inspections. Owners' USEPA Hazardous Waste Generator ID# GAR000075085 . | Provide record of Hazardous Waste collection area inspections. | Support | Primary | Weekly |
| Hazardous Waste Generation Summary. Owners' USEPA Hazardous Waste Generator ID# GAR000075085 . | Provides a summary of hazardous waste generated on the project on a monthly basis. | Support | Primary | Monthly |
| Hazardous Waste Determination. Owners' USEPA Hazardous Waste Generator ID# GAR000075085 . | Waste profiles are performed per 40 CFR 261 for each waste stream. | Support | Primary | Each Waste Stream |
| Waste Manifests. Owners' USEPA Hazardous Waste Generator ID# GAR000075085 | Provide waste manifest, chain-of-custody, bill of laden, recycle certifications, etc. to demonstrate cradle to grave for each waste stream. | Support | Primary | Each Item |
| Hazardous Waste Reduction Plan. Owners' USEPA Hazardous Waste Generator ID# GAR000075085. | Documents Owners' plan to minimize the generation of hazardous waste. Document was prepared due to being a LQG in 2016. | Primary | Support | As Needed |
| Hazardous Waste Contingency Plan. Owners' USEPA Hazardous Waste Generator ID# GAR000075085. | Owners' plan to protect the safety and welfare of employees and to comply with federal and state laws pertaining to hazardous waste generators with respect to preparedness and prevention for emergency events. | Primary | Support | As Needed |
| Solid Waste Management | | | | |
| Excess Concrete Management | Perform oversight of and support disposal. Costs by others. | Primary | Support | As Needed |
| Scrap Metal Recycling | Perform oversight of and support disposal. Costs by others. | Primary | Support | As Needed |
| Solid Waste | Perform oversight of and support disposal. Costs by others. | Primary | Support | As Needed |
| Hazardous Secondary Materials Management | Support profile development, oversight, and recycling of HSM. | Support | Primary | As Needed |

**Exhibit A – Scope of Work / Division of Responsibilities**

| Table 2. Environmental Compliance Division of Responsibility (Notes 1, 2) | | | | |
|---|---|---|---|---|
| **Title** | **Purpose** | **Owners Responsibility** | **Contractor Responsibility** | **Agency/Frequency/Dates** |
| Universal Waste | Provide oversight of, perform records management, and disposal of Universal Waste. | Support | Primary | As Needed |
| Used Oil | Provide oversight of, perform records management, and disposal of Used Oil. | Support | Primary | As Needed |
| Oily Debris | Provide oversight of, perform records management, and disposal of Oily Debris. | Support | Primary | As Needed |
| Manage Impacted Water (SPCC Containments, etc.) | Collect impacted water (from containments, etc.) provide oversight of, perform records management, and disposal of impacted water. | Support | Primary | As Needed |
| | | | | |
| | | | | |
| **5. HAZCOM/HAZMAT / SARA / EPCRA** | | | | |
| Chemical Control | All chemical products must be approved prior to purchase and require an “Approved Use Sticker” unless otherwise exempted. | Support | Primary | As Needed |
| Chemical Database Management/SDS Compliance | Support Safety and Health as needed. | Support | Primary | As Needed |
| Haz Com Plan Maintenance | Support Safety and Health as needed. | Support | Primary | As Needed |
| Chemical Cabinet Compliance | Ensure compliance with site procedure requirements to chemical cabinets (Currently ~400 cabinets. | Support | Primary | Weekly |
| Chemical Inventory Data for Owners' EPCRA / SARA Tier II Report | Used to identify and track Tier II and TRI reportable chemicals and quantities (CMS requirement and used to support Tier II Report). | Support | Primary | Monthly |
| Welding Rod Usage Log for Owners' TRI Report. | Track welding rod usage for Toxic Release Inventory Reporting To demonstrate that NESHAP is not applicable. | Support | Primary | Monthly |
| | | | | |
| **6. ECOLOGICAL / WILDLIFE** | | | | |
| Migratory Bird Treaty Act MBTA – Georgia Power's USFWS Permit | Provide protection of nesting birds and their eggs during construction activities. Provide records of related | Support | Primary | As Required |

**Exhibit A – Scope of Work / Division of Responsibilities**

| Table 2. Environmental Compliance Division of Responsibility (Notes 1, 2) | | | | |
|---|---|---|---|---|
| **Title** | **Purpose** | **Owners Responsibility** | **Contractor Responsibility** | **Agency/Frequency/Dates** |
| | | | | |
| MB745135-1 | activities. | | | |
| Feral Hog Management | Support USDA during activities to capture and remove feral hogs. Coordination required with site Safety and Security. | Primary | Support | As Required |
| Endangered Species / Nuisance Wildlife and Domestic Animal Protection / Relocation | Protect wildlife, site personnel and relocate animals. Provide records of related activities. | Support | Primary | As Required |
| | | | | |
| **7. OTHER REGULATORY OBLIGATIONS** | | | | |
| Noise | Perform monitoring to document compliance with the FEIS and SFEIS. | Primary | None | As Required |
| Environmental Protection Plan (COL Appendix B) - EIE for non-evaluated environmental impacts or changes to evaluated impacts | Perform notifications and prepare environmental impact evaluations to support compliance. | Primary | Support | As Required |
| Department of Army Permit SAS-2007-01837 | Support compliance with permit obligations. | Support | Primary | As Required |
| PaTON | Observe and support required signs. Sign replacement as required. | Support | Primary | |
| NHPA | Ensure compliance with NHPA requirements prior to any new land disturbing activities and support new discovery (if applicable)] | Primary | Support | As Required |
| Bulk Gas Impact | Perform Periodic Monitoring of Bulk Gas Shipments, storage locations, and management to comply with obligations for Vogtle 1&2. | Primary | Support | As Required |
| Federal Aviation Administration (FAA) Determinations. Various contractors and Owners make notifications. | Ensure applicable structures have determinations and are lit accordingly. Report lighting outages to the FAA as required. | Support | Primary | As Required |
| | | | | |

**Exhibit A – Scope of Work / Division of Responsibilities**

| Table 2. Environmental Compliance Division of Responsibility (Notes 1, 2) | | | | |
|---|---|---|---|---|
| **Title** | **Purpose** | **Owners Responsibility** | **Contractor Responsibility** | **Agency/Frequency/Dates** |
| | | | | |

Notes
1. Owners are responsible for Governance and Oversight for all items.
2. Definitions:
- **Governance** – Is the accountability to establish the standards, methods, and expectations for a Functional Area. These standards include management controls (policies, programs, processes, and implementing tools) and performance standards (definition of best practices and development of goals) that drive excellence in the function.
- **Oversight** – Is the accountability to critically monitor, assess, and evaluate the performance of the Functional Area throughout the fleet to provide assurance that standards are being met. Oversight includes the responsibility to recommend appropriate intervention and elevation/escalation of management attention as necessary when standards are NOT being met.
- **Support** – The accountability to arrange for supplemental resources or specialized skills to the performing organization on an as-needed basis. Support resources may provide technical guidance or specific work products; however, the performing organization retains ultimate accountability for the results and delivering on the work product.
- **Primary** – Is the accountability to deliver expected results/work products in accordance with the agreed upon fleet standards, methods, and expectations. The performing organization/Individual has the primary accountability for behaviors and execution.

**Exhibit B - Target Assumptions**

1. It is assumed that the bulk quantities to be installed as part of the Work are as stated in Tables 1 through 11 ("To-Go Quantities").

2. It is assumed that the number of mechanical and electrical components to be installed as part of the Work is as set forth in the document titled "Vogtle ETC Summary Working File Appendices provided to Bechtel Team.pdf." as uploaded on May 19, 2017 by Terry Takats to the SNC SharePoint site - "Vogtle 3&4 Project Controls".

3. It is assumed that, except for adjustment for escalation, the craft wages and/or benefits to be paid to craft labor engaged in performance of the Work are as stated in the Project Labor Agreement and wage bulletins provided in the following documents:

   - Document titled "Construction Labor Agreement.pdf." as uploaded on May 19, 2017 by Terry Takats to the SNC SharePoint site – "Vogtle 3&4 Project Controls."
   - Document titled "Craft Current Wages and Benefits.pdf." uploaded on May 25, 2017 by Terry Takats to the SNC SharePoint site – "Vogtle 3&4 Project Controls."
   - Document titled "BL0033 Effective 05.22.17.pdf" uploaded on May 26, 2017 by Terry Takats to the SNC SharePoint site – "Vogtle 3&4 Project Controls."

4. It is assumed that qualified craft labor will be available to support the performance of the Work in accordance with the resource curves for direct craft labor and indirect craft labor as set forth in Exhibit M-1.

   With respect to this Target Assumption:

   (a) Craft labor unavailability must be demonstrated by providing evidence for a defined craft labor group that issued craft requisitions have remained unfilled for 30 or more days for the lesser of a) [***] positions or b) [***] of the planned resource level for that craft labor group.

   (b) In the event that craft labor unavailability is demonstrated as provided in (a) above, the Parties will engage in consultation with the applicable craft labor union representatives, and, after such consultation, Contractor will make recommendations to the Owners as to proposed mitigation measures to address the craft labor unavailability. Such mitigation measures may include the proposed payment of per diems or provision of other incentives or benefits to the craft labor. As a part of any such recommendation, Contractor will provide data to support its recommendation, including, to the extent available, craft labor survey(s) or other data which indicate that the proposed mitigation measures would positively address the craft labor unavailability issue.

**Exhibit B - Target Assumptions**

(c) If Owners do not agree to implementation of a recommendation made by Contractor as provided in (b) above within 15 days of receipt of Contractor's recommendation, then Contractor may give notice of an Adjustment Event under the Agreement.

5. It is assumed that Contractor and its Subcontractors will be permitted to work on the Construction Site in accordance with the Work Schedule.

6. It is assumed that escalation on each cost category forming part of the Target Construction Cost, including craft labor costs, non-manual personnel costs, and construction material costs, will not exceed an annual average of [***] per year.

**Exhibit B - Target Assumptions**

| Table 1. To-Go Cast in Place Concrete Quantities (cubic yards) | | | |
|---|---|---|---|
| **Building** | **7/28/17 Assessment Quantities (Note 1)** | **Quantities Installed From Jun – Sep 2017** | **Remaining To-Go Quantities** |
| **UNIT 3** | | | |
| Containment | 2,100 | 150 | 1,950 |
| Auxiliary Building | 7,600 | 302 | 7,298 |
| Annex Building | 5,200 | 1,044 | 4,156 |
| Shield Building | 2,900 | 228 | 2,673 |
| Turbine Building | -- | 0 | 0 |
| Turbine Building – 1st Bay | 1,500 | 841 | 659 |
| Diesel Generator Building | 740 | -- | 740 |
| Radwaste Building | 1,530 | -- | 1,530 |
| **Total Unit 3** | **21,570** | **2,564** | **19,006** |
| **UNIT 4** | | | |
| Containment | 4,350 | 1,501 | 2,849 |
| Auxiliary Building | 10,100 | 445 | 9,655 |
| Annex Building | 7,400 | 634 | 6,766 |
| Shield Building | 2,900 | 0 | 2,900 |
| Turbine Building | 6,000 | 32 | 5,968 |
| Turbine Building – 1st Bay | 2,100 | Included above | 2,100 |
| Diesel Generator Building | 737 | 0 | 737 |
| Radwaste Building | 1,530 | 0 | 1,530 |
| **Total Unit 4** | **35,120** | **2,613** | **32,504** |
| **SITE** | | | |
| **Total Site** | **45,140** | **4,766** | **40,374** |

Notes

1. From Table 5-1 of Bechtel's July 28, 2017, "Cost and Schedule Assessment for the Completion of Construction for Southern Nuclear Operating Company's Vogtle Units 3 & 4". (Note: The Diesel Generator Building and Radwaste Building quantities for Unit 3 were inadvertently switched in Bechtel's July 28, 2017 assessment report and have been corrected in this table.)

## Exhibit B - Target Assumptions

| Table 2. To-Go Modular Concrete Quantities (cubic yards) | | | |
|---|---|---|---|
| **Building** | **7/28/17 Assessment Quantities (Note 1)** | **Quantities Installed From Jun – Sep 2017** | **Remaining To-Go Quantities** |
| **UNIT 3** | | | |
| Containment | 1,900 | 0 | 1,900 |
| Auxiliary Building | 500 | 0 | 500 |
| Annex Building | 816 | 0 | 816 |
| Shield Building | 6,400 | 0 | 6,400 |
| Turbine Building | -- | 0 | 0 |
| Turbine Building – 1 st Bay | -- | 0 | 0 |
| Diesel Generator Building | -- | 0 | 0 |
| Radwaste Building | -- | 0 | 0 |
| **Total Unit 3** | **9,616** | **0** | **9,616** |
| **UNIT 4** | | | |
| Containment | 2,900 | 0 | 2,900 |
| Auxiliary Building | 1,950 | 0 | 1,950 |
| Annex Building | -- | 0 | 0 |
| Shield Building | 7,200 | 547 | 6,653 |
| Turbine Building | -- | 0 | 0 |
| Turbine Building – 1 st Bay | -- | 0 | 0 |
| Diesel Generator Building | -- | 0 | 0 |
| Radwaste Building | -- | 0 | 0 |
| **Total Unit 4** | **12,050** | **547** | **11,503** |
| **SITE** | | | |
| **Total Site** | **0** | **0** | **0** |

Notes
1. From Table 5-1 of Bechtel's July 28, 2017, "Cost and Schedule Assessment for the Completion of Construction for Southern Nuclear Operating Company's Vogtle Units 3 & 4".

## Exhibit B - Target Assumptions

**Table 3. To-Go Structural Steel Quantities (tons)**

| Building | 7/28/17 Assessment Quantities (Note 1) | Quantities Installed From Jun – Sep 2017 | Remaining To-Go Quantities |
|---|---|---|---|
| **UNIT 3** | | | |
| Containment | 830 | 73 | 757 |
| Auxiliary Building | 490 | 36 | 454 |
| Annex Building | 1,035 | 290 | 745 |
| Shield Building | 920 | 0 | 920 |
| Turbine Building | 50 | 261 | 0 |
| Turbine Building – 1 st Bay | -- | 0 | 0 |
| Diesel Generator Building | -- | 0 | 0 |
| Radwaste Building | -- | 0 | 0 |
| **Total Unit 3** | **3,325** | **660** | **2,876** |
| **UNIT 4** | | | |
| Containment | 830 | 3 | 827 |
| Auxiliary Building | 490 | 64 | 426 |
| Annex Building | 1,380 | 444 | 936 |
| Shield Building | 920 | 0 | 920 |
| Turbine Building | 5,050 | 1,771 | 3,279 |
| Turbine Building – 1 st Bay | -- | 0 | 0 |
| Diesel Generator Building | -- | 0 | 0 |
| Radwaste Building | -- | 0 | 0 |
| **Total Unit 4** | **8,670** | **2,283** | **6,387** |
| **SITE** | | | |
| **Total Site** | **100** | **236** | **0** |

Notes
1. From Table 5-1 of Bechtel's July 28, 2017, "Cost and Schedule Assessment for the Completion of Construction for Southern Nuclear Operating Company's Vogtle Units 3 & 4".

**Exhibit B - Target Assumptions**

**Table 4. To-Go Large Bore Pipe Quantities (linear feet)**

| **Building** | **7/28/17 Assessment Quantities (Note 1)** | **Quantities Installed From Jun – Sep 2017** | **Remaining To-Go Quantities** |
|---|---|---|---|
| **UNIT 3** | | | |
| Containment | 7,600 | 1,183 | 6,417 |
| Auxiliary Building | 14,600 | 3,732 | 10,868 |
| Annex Building | 10,000 | 607 | 9,393 |
| Shield Building | -- | 0 | 0 |
| Turbine Building | 62,000 | 5,090 | 56,910 |
| Turbine Building – 1st Bay | Included above | Included above | Included above |
| Diesel Generator Building | 2,400 | 0 | 2,400 |
| Radwaste Building | 2,100 | 0 | 2,100 |
| **Total Unit 3** | **98,700** | **10,612** | **88,088** |
| **UNIT 4** | | | |
| Containment | 8,000 | 290 | 7,710 |
| Auxiliary Building | 15,500 | 1,337 | 14,163 |
| Annex Building | 11,580 | 385 | 11,195 |
| Shield Building | -- | 0 | 0 |
| Turbine Building | 67,330 | 1,903 | 65,427 |
| Turbine Building – 1st Bay | Included above | Included above | Included above |
| Diesel Generator Building | 2,400 | 0 | 2,400 |
| Radwaste Building | 2,100 | 0 | 2,100 |
| **Total Unit 4** | **106,910** | **3,916** | **102,994** |
| **SITE** | | | |
| **Total Site** | **48,000** | **8,272** | **39,728** |

Notes
1. From Table 5-2 of Bechtel's July 28, 2017, "Cost and Schedule Assessment for the Completion of Construction for Southern Nuclear Operating Company's Vogtle Units 3 & 4". (Note: The Diesel Generator Building and Radwaste Building quantities for Unit 3 and Unit 4 were inadvertently switched in Bechtel's July 28, 2017 assessment report and have been corrected in this table.)

**Exhibit B - Target Assumptions**

| Table 5. To-Go Large Bore Pipe Hangers (each) | | | |
|---|---|---|---|
| **Building** | **7/28/17 Assessment Quantities (Note 1)** | **Quantities Installed From Jun – Sep 2017** | **Remaining To-Go Quantities** |
| **UNIT 3** | | | |
| Containment | 740 | 36 | 704 |
| Auxiliary Building | 950 | 85 | 865 |
| Annex Building | 1,040 | 105 | 935 |
| Shield Building | -- | 0 | 0 |
| Turbine Building | 4,150 | 444 | 3,706 |
| Turbine Building – 1 st Bay | Included above | Included above | Included above |
| Diesel Generator Building | 190 | 0 | 190 |
| Radwaste Building | 150 | 0 | 150 |
| **Total Unit 3** | **7,220** | **670** | **6,550** |
| **UNIT 4** | | | |
| Containment | 740 | 0 | 740 |
| Auxiliary Building | 950 | 17 | 933 |
| Annex Building | 1,040 | 0 | 1,040 |
| Shield Building | -- | 0 | 0 |
| Turbine Building | 4,150 | 549 | 3,601 |
| Turbine Building – 1 st Bay | Included above | Included above | Included above |
| Diesel Generator Building | 190 | 0 | 190 |
| Radwaste Building | 150 | 0 | 150 |
| **Total Unit 4** | **7,220** | **566** | **6,654** |
| **SITE** | | | |
| **Total Site** | **850** (Note 2) | **0** | **850** |

Notes
1. From Table 5-2 of Bechtel's July 28, 2017, "Cost and Schedule Assessment for the Completion of Construction for Southern Nuclear Operating Company's Vogtle Units 3 & 4". (Note: The Diesel Generator Building and Radwaste Building quantities for Unit 3 and Unit 4 were inadvertently switched in Bechtel's July 28, 2017 assessment report and have been corrected in this table.)
2. The large bore pipe hangers for the site were inadvertently not included in Bechtel's July 28, 2017 assessment report and have been corrected in this table.

## Exhibit B - Target Assumptions

| Table 6. To-Go Small Bore Pipe Quantities (linear feet) | | | |
|---|---|---|---|
| **Building** | **7/28/17 Assessment Quantities (Note 1)** | **Quantities Installed From Jun – Sep 2017** | **Remaining To-Go Quantities** |
| **UNIT 3** | | | |
| Containment | 14,500 | 2,436 | 12,064 |
| Auxiliary Building | 14,800 | 4,099 | 10,701 |
| Annex Building | 11,000 | 796 | 10,204 |
| Shield Building | -- | 0 | 0 |
| Turbine Building | 57,000 | 770 | 56,230 |
| Turbine Building – 1 st Bay | Included above | Included above | Included above |
| Diesel Generator Building | 1,500 | 0 | 1,500 |
| Radwaste Building | 2,200 | 0 | 2,200 |
| **Total Unit 3** | **101,000** | **8,101** | **92,899** |
| **UNIT 4** | | | |
| Containment | 15,455 | 1,773 | 13,682 |
| Auxiliary Building | 15,320 | 387 | 14,933 |
| Annex Building | 11,830 | 148 | 11,682 |
| Shield Building | -- | 0 | 0 |
| Turbine Building | 57,800 | 216 | 57,584 |
| Turbine Building – 1 st Bay | Included above | Included above | Included above |
| Diesel Generator Building | 1,500 | 0 | 1,500 |
| Radwaste Building | 2,200 | 0 | 2,200 |
| **Total Unit 4** | **104,100** | **2,524** | **101,581** |
| **SITE** | | | |
| **Total Site** | **18,500** | **0** | **18,500** |

Notes

1. From Table 5-2 of Bechtel's July 28, 2017, "Cost and Schedule Assessment for the Completion of Construction for Southern Nuclear Operating Company's Vogtle Units 3 & 4". (Note: The Diesel Generator Building and Radwaste Building quantities for Unit 3 and Unit 4 were inadvertently switched in Bechtel's July 28, 2017 assessment report and have been corrected in this table.)

**Exhibit B - Target Assumptions**

**Table 7. To-Go Small Bore Pipe Hangers (each)**

| **Building** | **7/28/17 Assessment Quantities (Note 1)** | **Quantities Installed From Jun – Sep 2017** | **Remaining To-Go Quantities** |
|---|---|---|---|
| **UNIT 3** | | | |
| Containment | 2,280 | 24 | 2,256 |
| Auxiliary Building | 1,650 | 295 | 1,355 |
| Annex Building | 2,100 | 52 | 2,048 |
| Shield Building | -- | 0 | 0 |
| Turbine Building | 6,800 | 111 | 6,689 |
| Turbine Building – 1 st Bay | Included above | Included above | Included above |
| Diesel Generator Building | 200 | 0 | 200 |
| Radwaste Building | 300 | 0 | 300 |
| **Total Unit 3** | **13,330** | **482** | **12,848** |
| **UNIT 4** | | | |
| Containment | 2,280 | 0 | 2,280 |
| Auxiliary Building | 1,650 | 38 | 1,612 |
| Annex Building | 2,100 | 0 | 2,100 |
| Shield Building | -- | 0 | - |
| Turbine Building | 6,800 | 6 | 6,794 |
| Turbine Building – 1 st Bay | Included above | Included above | Included above |
| Diesel Generator Building | 200 | 0 | 200 |
| Radwaste Building | 300 | 0 | 300 |
| **Total Unit 4** | **13,330** | **44** | **13,286** |
| **SITE** | | | |
| **Total Site** | **Not specified** | **0** | **0** |

Notes
1. From Table 5-2 of Bechtel's July 28, 2017, "Cost and Schedule Assessment for the Completion of Construction for Southern Nuclear Operating Company's Vogtle Units 3 & 4". (Note: The Diesel Generator Building and Radwaste Building quantities for Unit 3 and Unit 4 were inadvertently switched in Bechtel's July 28, 2017 assessment report and have been corrected in this table.)

**Exhibit B - Target Assumptions**

**Table 8. To-Go Scheduled Cable Quantities (linear feet)**

| Building | 7/28/17 Assessment Quantities (Note 1) | Quantities Installed From Jun – Sep 2017 | Remaining To-Go Quantities |
|---|---|---|---|
| **UNIT 3** | | | |
| Containment | 350,000 | 105 | 349,895 |
| Auxiliary Building | 1,150,000 | 1,300 | 1,148,700 |
| Annex Building | 720,000 | 9,534 | 710,466 |
| Shield Building | -- | 100 | 0 |
| Turbine Building | 1,680,000 | 3,000 | 1,677,000 |
| Turbine Building – 1st Bay | Included above | Included above | Included above |
| Diesel Generator Building | 90,000 | 0 | 90,000 |
| Radwaste Building | 92,000 | 0 | 92,000 |
| **Total Unit 3** | **4,082,000** | **14,039** | **4,068,061** |
| **UNIT 4** | | | |
| Containment | 350,000 | 425 | 349,575 |
| Auxiliary Building | 1,150,000 | 2,007 | 1,147,993 |
| Annex Building | 720,000 | 2,949 | 717,051 |
| Shield Building | -- | 0 | 0 |
| Turbine Building | 1,680,000 | 1,704 | 1,678,296 |
| Turbine Building – 1st Bay | Included above | Included above | Included above |
| Diesel Generator Building | 90,000 | 0 | 90,000 |
| Radwaste Building | 92,000 | 0 | 92,000 |
| **Total Unit 4** | **4,082,000** | **7,085** | **4,074,915** |
| **SITE** | | | |
| Standard Plant Scope | 330,060 | 10,588 | 319,472 |
| Site Specific | 1,284,800 | Included above | 1,284,800 |
| **Total Site** | **1,614,860** | **10,588** | **1,604,272** |

Notes

1. From Table 5-3 of Bechtel's July 28, 2017, "Cost and Schedule Assessment for the Completion of Construction for Southern Nuclear Operating Company's Vogtle Units 3 & 4". (Note: The Diesel Generator Building and Radwaste Building quantities for Unit 3 and Unit 4 were inadvertently switched in Bechtel's July 28, 2017 assessment report and have been corrected in this table.)

**Exhibit B - Target Assumptions**

**Table 9. To-Go Scheduled Conduit Quantities (linear feet)**

| Building | 7/28/17 Assessment Quantities (Note 1) | Quantities Installed From Jun – Sep 2017 | Remaining To-Go Quantities |
|---|---|---|---|
| **UNIT 3** | | | |
| Containment | 19,000 | 28 | 18,972 |
| Auxiliary Building | 21,000 | 559 | 20,441 |
| Annex Building | 43,000 | 7,706 | 35,294 |
| Shield Building | -- | 0 | 0 |
| Turbine Building | 91,000 | 317 | 90,683 |
| Turbine Building – 1st Bay | Included above | Included above | Included above |
| Diesel Generator Building | 6,400 | 0 | 6,400 |
| Radwaste Building | 5,200 | 0 | 5,200 |
| **Total Unit 3** | **185,600** | **8,610** | **176,990** |
| **UNIT 4** | | | |
| Containment | 19,000 | 316 | 18,684 |
| Auxiliary Building | 21,000 | 362 | 20,638 |
| Annex Building | 43,000 | 0 | 43,000 |
| Shield Building | -- | 0 | 0 |
| Turbine Building | 91,000 | 2,442 | 88,558 |
| Turbine Building – 1st Bay | Included above | Included above | Included above |
| Diesel Generator Building | 6,400 | 0 | 6,400 |
| Radwaste Building | 5,200 | 0 | 5,200 |
| **Total Unit 4** | **185,600** | **3,120** | **182,480** |
| **SITE** | | | |
| Standard Plant Scope | 2,460 | 9,763 | 0 |
| Site Specific | Included above | Included above | 0 |
| **Total Site** | **2,460** | **9,763** | **0** |

Notes

1. From Table 5-3 of Bechtel's July 28, 2017, "Cost and Schedule Assessment for the Completion of Construction for Southern Nuclear Operating Company's Vogtle Units 3 & 4". (Note: The Diesel Generator Building and Radwaste Building quantities for Unit 3 and Unit 4 were inadvertently switched in Bechtel's July 28, 2017 assessment report and have been corrected in this table.)

**Exhibit B - Target Assumptions**

**Table 10. To-Go Cable Tray Quantities (linear feet)**

| **Building** | **7/28/17 Assessment Quantities (Note 1)** | **Quantities Installed From Jun – Sep 2017** | **Remaining To-Go Quantities** |
|---|---|---|---|
| **UNIT 3** | | | |
| Containment | 7,000 | 0 | 7,000 |
| Auxiliary Building | 13,500 | 94 | 13,406 |
| Annex Building | 11,400 | 385 | 11,015 |
| Shield Building | -- | 0 | 0 |
| Turbine Building | 19,000 | 2,847 | 16,153 |
| Turbine Building – 1st Bay | Included above | Included above | Included above |
| Diesel Generator Building | 500 | 0 | 500 |
| Radwaste Building | 1,000 | 0 | 1,000 |
| **Total Unit 3** | **52,400** | **3,326** | **49,074** |
| **UNIT 4** | | | |
| Containment | 7,000 | 0 | 7,000 |
| Auxiliary Building | 13,500 | 216 | 13,284 |
| Annex Building | 11,400 | 394 | 11,006 |
| Shield Building | -- | 0 | 0 |
| Turbine Building | 19,000 | 115 | 18,885 |
| Turbine Building – 1st Bay | Included above | Included above | Included above |
| Diesel Generator Building | 500 | 0 | 500 |
| Radwaste Building | 1,000 | 0 | 1,000 |
| **Total Unit 4** | **52,400** | **725** | **51,675** |
| **SITE** | | | |
| Standard Plant Scope | 7,200 | 4,916 | 2,284 |
| Site Specific | Included above | Included above | Included above |
| **Total Site** | **7,200** | **4,916** | **2,284** |

Notes
1. From Table 5-3 of Bechtel's July 28, 2017, "Cost and Schedule Assessment for the Completion of Construction for Southern Nuclear Operating Company's Vogtle Units 3 & 4". (Note: The Diesel Generator Building and Radwaste Building quantities for Unit 3 and Unit 4 were inadvertently switched in Bechtel's July 28, 2017 assessment report and have been corrected in this table.)

**Exhibit B - Target Assumptions**

| Table 11. To-Go Cable Terminations Quantities (each) | | | |
|---|---|---|---|
| **Building** | **7/28/17 Assessment Quantities (Note 1)** | **Quantities Installed From Jun – Sep 2017** | **Remaining To-Go Quantities** |
| **UNIT 3** | | | |
| Containment | 29,560 | 0 | 29,560 |
| Auxiliary Building | 54,670 | 0 | 54,670 |
| Annex Building | 34,670 | 0 | 34,670 |
| Shield Building | -- | 0 | 0 |
| Turbine Building | 43,480 | 0 | 43,480 |
| Turbine Building – 1st Bay | Included above | Included above | Included above |
| Diesel Generator Building | 4,565 | 0 | 4,565 |
| Radwaste Building | 3,690 | 0 | 3,690 |
| **Total Unit 3** | **170,640** | **0** | **170,640** |
| **UNIT 4** | | | |
| Containment | 29,560 | 0 | 29,560 |
| Auxiliary Building | 54,670 | 0 | 54,670 |
| Annex Building | 34,670 | 0 | 34,670 |
| Shield Building | -- | 0 | 0 |
| Turbine Building | 43,480 | 0 | 43,480 |
| Turbine Building – 1st Bay | Included above | Included above | Included above |
| Diesel Generator Building | 4,565 | 0 | 4,565 |
| Radwaste Building | 3,690 | 0 | 3,690 |
| **Total Unit 4** | **170,640** | **0** | **170,640** |
| **SITE** | | | |
| Standard Plant Scope | 29,850 | 282 | 29,568 |
| Site Specific | Included above | Included above | Included above |
| **Total Site** | **29,850** | **282** | **29,568** |

Notes
1. From Table 5-3 of Bechtel's July 28, 2017, "Cost and Schedule Assessment for the Completion of Construction for Southern Nuclear Operating Company's Vogtle Units 3 & 4". (Note: The Diesel Generator Building and Radwaste Building quantities for Unit 3 and Unit 4 were inadvertently switched in Bechtel's July 28, 2017 assessment report and have been corrected in this table.)

**Exhibit C – Baseline Schedule**

[***]

**Exhibit D – Construction Site**

| Building Number | Building Description | Non-Construction Site Areas | Construction Site Areas |
|---|---|---|---|
| 101 | Batch Plant Office #1 | | X |
| 102 | SSM (HVAC) Subcontractor | | X |
| 103 | Non-Manual Time Alley (turnstiles) Security Post 2 | X | |
| 104 | Construction Warehouse | | X |
| 104a | Construction Warehouse Offices (Trailer #4) | | X |
| 104b | Warehouse Storage | | X |
| 104c | WH Annex Offices (including trailer 104c1) | | X |
| 104d | WH Storage | | X |
| 104e | WH Storage | | X |
| 104f | WH Storage | | X |
| 105 | WH Laydown Yard | | X |
| 106 | Non-Manual Parking lot | | X |
| 107 | Batch Plant Area | | X |
| 108 | Containment Vessel Module Assembly Pad | | X |
| 109 | NRC Office | X | |
| 109A | NRC Office | X | |
| 109B | NRC Office | X | |
| 109C | NRC Office | X | |
| 110 | Weld Material Storage Building for CBIS | | X |
| 111 | Turbine Building Module Assembly Area | | X |
| 112 | Test Lab | X (Note 1) | X (Note 1) |
| 112A | WECTEC IT | X | |
| 113 | Ameco Tool Issue Trailer #1 | | X |
| 114 | Craft/Subcontractor Parking Lot #1 | | X |
| 115 | Batch Plant Office #2 | | X |
| 116 | Time Alley (Turnstiles) Security Post 3 | X | |
| 117 | Time Office Building | X (Note 1) | X (Note 1) |
| 117A | Time Office Building Annex | X (Note 1) | X (Note 1) |
| 118 | New Hire & In-Processing Building | X | |
| 119 | Craft Toilet Trailer #1 | | X |
| 120 | Construction Management Building | X | |
| 120A | FE Annex Offices | X (Note 1) | X (Note 1) |
| | | | |

**Exhibit D – Construction Site**

| Building Number | Building Description | Non-Construction Site Areas | Construction Site Areas |
|---|---|---|---|
| | | | |
| 121 | Project Services Office Building | X (Note 1) | X (Note 1) |
| 121A | Procurement | X (Note 1) | X (Note 1) |
| 121B | Procurement Engineering | X | |
| 121C | Construction Services (COS) Building | X (Note 1) | X (Note 1) |
| 122 | Amec/Materials Warehouse | X (Note 2) | X (Note 2) |
| 123 | Nuclear Island & Turbine Island Unit 4 Area (Includes Craft Break Tents) | | X |
| 124 | Construction Management Offices | X (Note 1) | X (Note 1) |
| 124A | Construction Office Annex | X (Note 1) | X (Note 1) |
| 124B | Construction QC/Welding office Annex | X (Note 1) | X (Note 1) |
| 124C | Construction Office Annex | X (Note 1) | X (Note 1) |
| 125 | Craft Toilet Trailer #2 | | X |
| 126 | Craft Toilet Trailer #3 | | X |
| 127 | Craft Toilet Trailer #4 | | X |
| 128 | Craft Toilet Trailer #5 | | X |
| 129 | Craft Toilet Trailer #6 | | X |
| 130 | Construction /Craft Change Building #2 (including 130A) | | X |
| 131 | Pipefitters Shop | | X |
| 132 | Electrical Shop | | X |
| 133 | Carpenter Shop | | X |
| 134 | Weld Testing Building | | X |
| 135 | Bottle Gas Storage | | X |
| 136 | Vehicle Repair Shop | | X |
| 137 | Motor Pool Yard | | X |
| 138 | Laydown Area #1 | | X |
| 139 | Rebar Module Pad U3 | | X |
| 140 | Owners Executives Office | X | |
| 141 | Air Compressor Building #2 | | X |
| 142 | HSE Facility | X | X |

**Exhibit D – Construction Site**

| Building Number | Building Description | Non-Construction Site Areas | Construction Site Areas |
|---|---|---|---|
| | | | |
| | | (Note 1) | (Note 1) |
| 142A | HSE Office Annex | X<br>(Note 1) | X<br>(Note 1) |
| 142B | HSE Office Annex - First Aid Facility | X<br>(Note 1) | X<br>(Note 1) |
| 143 | Tool Room & Rigging Loft | | X |
| 145 | Security Field Office | X | |
| 145A | Security Access Post 1 | X | |
| 146 | HSE HazMat Facility | | |
| 147 | Fiber Optics Building | X | |
| 148 | Owners Auditorium Building | X | |
| 149 | Module Assembly Area | | X |
| 150 | (MAB) Module Assembly Building<br>(including conex units a,b,c,d) | | X |
| 151 | Chemical Storage Building #2 | | X |
| 152 | Fuel Station | | X |
| 153 | Security Main Guard House - SEC Post 1 | X | |
| 154 | Warehouse Offices and Level "A" Storage | | X |
| 155 | Security Secondary Guard House - Post 8A | X | |
| 156 | Craft Shelter Outer Module Fab Area | | X |
| 157 | Temp. Construction Office Trailers | X<br>(Note 1) | X<br>(Note 1) |
| 158 | Carpenter Form Pad | | X |
| 159 | Module Assembly Building Document Control | | X |
| 160 | Office Trailer #1 | X<br>(Note 1) | X<br>(Note 1) |
| 161 | Office Trailer #2 | X<br>(Note 1) | X<br>(Note 1) |
| 162 | Training Office Annex (including 162A) | X<br>(Note 1) | X<br>(Note 1) |
| 163 | EH&S Training Facility | | X |
| 164 | Survey Support Facility | | X |
| 165 | Owners Office Building (West) | X | |
| 166 | CBIS Laydown Area | | X |
| 167 | Turbine Building (TB) Field Office Area | | X |
| 168 | Turbine Building Toilet Trailer | | X |
| 169 | NI/TI Doc Control | | X |
| | | | |

**Exhibit D – Construction Site**

| Building Number | Building Description | Non-Construction Site Areas | Construction Site Areas |
|---|---|---|---|
| | | | |
| 170 | EH&S Training Facility | | X |
| 171 | NI-3 Field Offices & Craft Change Area | | X |
| 171A | NI-4 Field Engineering Offices | X (Note 1) | X (Note 1) |
| 171B | Office Trailers | X (Note 1) | X (Note 1) |
| 172 | NI-3 Toilet Trailer | | X |
| 173 | NI Rigger Containers | | X |
| 174 | Batch Plant QC Field Office | | X |
| 175 | Electrical Laydown Yard | | X |
| 176 | Site Cylinder Filling Station | | X |
| 177 | Ameco Tool Issue Trailer #1 | | X |
| 178 | Vehicle Repair Shop (Temporary) | | X |
| 179 | AMECO Tool Storage | | X |
| 180 | AMECO Tool Storage | | X |
| 181 | Coating & Painting Shop | | X |
| 182 | Cooling Tower Contractor Offices | | X |
| 183 | Cooling Tower HSE Field Office | | X |
| 184 | Valve and I&C Shop | X (Note 3) | X (Note 3) |
| 185 | Owners ITAAC/Licensing Building | X | |
| 186 | Owners Co-Owners Offices | X | |
| 187 | Shield Building Offices | X | |
| 188 | CQC Annex Offices | X | |
| 189 | Chemical Storage Building #1 | | X |
| 190 | Engineering Building | X | |
| 191 | LR/HR Office | X (Note 1) | X (Note 1) |
| 192 | Mistras NDE Field Office | | X |
| 194 | Pipe Shop Laydown | | X |
| 195 | NI Rebar Mockup Area | | X |
| 196 | Office Trailer #3 | X (Note 1) | X (Note 1) |
| 197 | Office Trailer #4 | X (Note 1) | X (Note 1) |
| 198 | Office Trailer #5 | X (Note 1) | X (Note 1) |
| | | | |
| | | | |

**Exhibit D – Construction Site**

| Building Number | Building Description | Non-Construction Site Areas | Construction Site Areas |
|---|---|---|---|
| | | | |
| 199 | Access Authorization / Badging Building | X | |
| 200 | Pre Hire Welding Test Facility A&B | | X |
| 201 | (ASB) Admin Support Building | X<br>(Note 1) | X<br>(Note 1) |
| 202 | NDE / RT Film Trailer | | X |
| 203 | Field QC | | X |
| 203 B | Mistras | | X |
| 204 | HSE Training Lab (including 204 A&B) | X<br>(Note 1) | X<br>(Note 1) |
| 205 | Office Trailer #7 | X<br>(Note 1) | X<br>(Note 1) |
| 206 | Not Used | | |
| 207 | Startup Field Offices | X | |
| 208 | Craft Toilet Trailer #8 | | X |
| 209 | Construction Control Facility (OCC) | X | |
| 210 | Conex Field Office | | X |
| 211 | CBIS Shield Building Offices A&B | | X |
| 212 | Shield Building Prefab Field Offices<br>(and 212A) | | X |
| 301 | Office Building | X | |
| 302 | Engineering Administration Building | X | |
| 303 | Maintenance Support Building | X | |
| 304 | Personnel Access Point | X | |
| 305 | Communication Support Center | X | |
| 306 | Receiving Warehouse<br>(used as construction warehouse) | | X |
| 307 | Warehouse | X<br>(Note 1) | X<br>(Note 1) |
| 308 | ISFSI | X | |
| 309 | Vogtle Training Center Expansion Area | X | |
| 311 | Fire Training Facilities | X | |
| 312 | New Visitor Center | X | |
| 313 | Blowdown Sump | X | |
| 314 | Switch Yard Control House | X | |
| 315 | Pumphouse Switchgear Area | X | |
| 316 | Bulk Gas Storage Facility | X | |
| 317 | CWS Chemical Treatment Skids | X | |
| | | | |
| | | | |

## Exhibit D – Construction Site

| Building Number | Building Description | Non-Construction Site Areas | Construction Site Areas |
|---|---|---|---|
| | | | |
| 318 | Security Towers | X | |
| 319 | Not Used | | |
| 320 | Not Used | | |
| 321 | Diesel Fuel Offloading Station | X | |
| 322 | Radioactive Material and Equipment Storage Building | X | |
| 323 | Not Used | | |
| 324 | Rotor & Cable Storage Building<br>(Currently used as a warehouse) | | X |
| 325 | Waste Water Discharge Structure | X | |
| 326 | River Water Intake Structure | X | |
| 327 | Cooling Tower Basin and Pump Station | X | |
| 328 | Primary VAP | X | |
| 329 | Secondary VAP | X | |

Notes

1. Owners will maintain Building/Facilities. Contractor controls office layout and personnel movement.
2. Shared asset with Facilities for storage and distribution of facilities materials. Owners will maintain the building.
3. Contractor will control facility maintenance. Owners Controls South End Offices.

**Exhibit E – Subcontract Alignment Process and Managed Subcontracts**

The Subcontract Scope Alignment Process means the process for the Contractor's evaluation of Contractor-Managed Subcontract Scope as described in this Exhibit.

Table 1 (located on page 4) provides a list of subcontract scope items for the Facility identified as either "Managed by Owner" or "Managed by Contractor" (i.e., Contractor-Managed Subcontract Scope).

The Subcontract Scope Alignment Process will be performed by Contractor, in consultation with Owners. The following items will be evaluated for each element of Contractor-Managed Subcontract Scope:

- Scope of work/technical services remaining to be performed to support Final Completion including identification of potential scope gaps and unidentified scope
- Schedule to complete
- Cost estimate to complete (for scope remaining to be completed as of the Effective Date)
- Allowance for growth in scope, if applicable
- Appropriate contingency
- Resources and capabilities of incumbent subcontractor
- Safety requirements and provisions
- Risk assessment
- Existing commercial arrangement with incumbent subcontractor (both with respect to the identity of the subcontractor and the terms of the subcontract) including general and special conditions, reporting requirements, financial capabilities, etc.

For each scope item, access to the following information will be provided by the Owners on a timely basis to perform the evaluation:

- Current subcontract for the scope including terms and conditions (general conditions, special conditions) and referenced attachments
- Scope of work/technical services (if separate from the existing subcontract)
- Estimate to complete data with supporting details to enable review/validation of values
- Payment status (paid to date, outstanding, Owners and/or subcontractor assessment of percent complete)
- Technical documents (e.g., Technical Documents List, Schedule of Required Vendor Data, etc.).

Discussions with each subcontractor are anticipated as part of the evaluation as well as participation in subcontract renegotiations. Owners assistance will be needed to facilitate these discussions.

The evaluation of each item of Contractor-Managed Subcontract Scope will be performed in three phases:

**Exhibit E – Subcontract Alignment Process and Managed Subcontracts**

- **Phase 1 – Review Existing Subcontract/Scope to Assess Current Estimate to Complete**

  In Phase 1, each element of Contractor-Managed Subcontract Scope and related subcontract (if any) will be reviewed to enable an assessment of Owners' current estimate to complete. A Review Package will be prepared for each element of Contractor-Managed Subcontract Scope that will include the following information:

1. Executive Summary
2. Scope of Work/Technical Services Remaining

   2.1 Scope Definition
   2.2 Work Included
   2.3 Work Not Included
   2.4 Potential Gaps
   2.5 Alternative Execution Approaches

3. Resources and Capabilities
4. Safety Requirements and Provisions
5. Risk Assessment

   5.1 Cost Risk
   5.2 Schedule Risk

6. Existing Commercial Arrangement/Proposal Evaluation

   6.1 General Conditions
   6.2 Special Conditions
   6.3 Reporting Requirements
   6.4 Financial Terms and Financial Condition of Incumbent Subcontractor
   6.5 Potential Gaps in Terms and Conditions
   6.6 Schedule Review

7. Schedule to Complete Defined Scope

   7.1 Impact to Baseline Schedule and Target Completion Date(s)

   The potential that items of Contractor-Managed Subcontract Scope could impact the Baseline Schedule will be evaluated.

**Exhibit E – Subcontract Alignment Process and Managed Subcontracts**

7.2 Contingency Assessment

All items of Contractor-Managed Subcontract Scope will be scheduled as necessary to support the Baseline Schedule.

7.3 Adjustment to Baseline Schedule and Target Completion Dates:

An adjustment to the Baseline Schedule and Target Completion Dates will be identified if the scope item will not support the current Baseline Schedule.

8. Cost Estimate to Complete

8.1 Cost Assessment

Contractor will assess the estimated cost to complete the scope item in question for scope remaining to be completed as of the Effective Date.

8.2 Allowance for Growth in Scope

The cost estimate will include an allowance for growth in scope, if applicable, based on Contractor's standard estimating processes.

8.3 Contingency Assessment

An appropriate amount for contingency will be included in the cost estimate to complete to achieve a confidence level of no less than 80% (using @Risk or similar software using Monte Carlo risk simulation).

8.4 Allowance for Escalation

An appropriate allowance for escalation, if applicable, will be included in the cost estimate to complete based on Contractor's assessment of escalation for the scope item in question.

8.5Adjustment to Target Construction Cost that include items 8.1 through 8.4

An adjustment to the Target Construction Cost will be identified based on the results of the evaluation, including items 8.1 through 8.4.

**Exhibit E – Subcontract Alignment Process and Managed Subcontracts**

- **Phase 2 – Review Re-Bid/Negotiation of Subcontract Scope to Assess Current Estimate to Complete**

  In Phase 2, the information received as part of the re-bid/negotiation of each subcontract will be reviewed to complete or identify any adjustments. The Phase 1 Review Package will be updated with the results of Phase 2.

- **Phase 3 – Agreement with Owners on Adjustment Needed to Target Construction Cost and Target Completion Date(s) (if any)**

  Multiple elements of Contractor-Managed Subcontract Scope may be reasonably considered as a group for these purposes, where mutually agreed.

**Exhibit E – Subcontract Alignment Process and Managed Subcontracts**

| Table 1. Construction Subcontracts (Note 1) | | | | |
|---|---|---|---|---|
| **Number** | **Title/Scope Description** | **Current Subcontractor** | **Managed by Owner (Owner-Managed Subcontract)** | **Managed by Contractor (Contractor-Managed Subcontract)** |
| 1270 | Non-union general facilities maintenance | David Smith Construction | X | |
| 1278 | Data and Cabling | Heath | X | |
| 1399 | Excavation NI, Misc earthwork | Morgan Corporation | | X |
| 1421 | Concrete and Soil Testing | AMEC | | X |
| 1422 | Backfill for Nuclear Islands | Morgan Corp | | X |
| 1430 | RWI Structure Site Development (dewatering of area to support RWI construction) | Remedial Construction Services | | X |
| 1452 | Underground HDPE Pipe Installation | C.A. Murren | | X |
| 1456 | River Water Intake Structure (civil only) Phase II | Garney | | X |
| 1464 | Durawall | TBD | | X |
| 1466 | NDE Testing | Mistras | | X |
| 1468 | High Voltage Electrical Work | Georgia Power | X | |
| 1477 | Productivity Survey Consultant | Productivity Enhancement | X | |
| 1600 | Landscaping | TBD | X | |
| 1608 | Electric Heat Tracing and Insulation | TBD | | X |
| 1612 | Specialized Field Machining | PCI | | X |
| 1613 | ISO Phase & Non-Seg Bus Duct | AZZ/Calvert | | X |
| 1614 | Transformer Dress-out | ABB | | X |
| 1615 | Lightning Protection | TBD | | X |
| 1618 | Coatings | Williams Specialty Services | | X |
| 1620 | Trash Hauling / Disposal | Waste Management | X | |
| 1622 | Formwork | HSG | | X |
| 1625 | HVAC Fab & Installation (U3 & U4) | SSMI | | X |
| 1626 | Building 307 | Thompson Turner Construction | X | |
| 1627 | Field Erected Tanks | CB&I | X (Note 2) | X (Note 2) |
| | | | | |

**Exhibit E – Subcontract Alignment Process and Managed Subcontracts**

| Table 1. Construction Subcontracts (Note 1) | | | | |
|---|---|---|---|---|
| **Number** | **Title/Scope Description** | **Current Subcontractor** | **Managed by Owner (Owner-Managed Subcontract)** | **Managed by Contractor (Contractor-Managed Subcontract)** |
| 1631 | Vac Truck Services | August Industrial | | X |
| 1632 | Shield Building Construction | CB&I | X (Note 2) | X (Note 2) |
| 1633 | Potable Water System Maintenance | Nalco | X | |
| 1636 | Cooling Tower Construction | Research Cottrell Cooling (RCC) | | X |
| 1637 | Small Tools and Consumables | TBD | | X |
| 1802 | Concrete Pump Trucks | Ashmore | | X |
| 1803 | Post Weld Heat Treatment | Superheat FGH Services | | X |
| 1804 | Vac Truck Services | Thompson Industrial | | X |
| 1805 | Vac Truck Services | EnviroVac | | X |
| 1806 | Concrete and Soil Testing | S&ME | | X |
| 1807 | Special High Value Tools | TBD | | X |
| 1808 | Heavy Haul | TBD | | X |
| 1809 | Raw Water Pump Replacement | TBD | X | |
| 1811 | Traction Elevators | Thyssen Krupp | | X |
| 1812 | Fire Protection / Detection | F.E. Moran | | X |
| 1813 | Permanent Plant Communications | TBD | X | |
| 1814 | SWS Chemical Treatment Building | TBD | | X |
| 1815 | Insulation (conventional) | TBD | | X |
| 1817 | Metal Siding | Commercial Siding | | X |
| 1818 | Membrane Roofing | TBD | | X |
| 1819 | Penetration Seals (Block outs/barriers) | TBD | | X |
| 1822 | Annulus Seal – Waterproof Sealants | TBD | | X |
| 1824 | Permanent Plant Security System | TBD | X | |
| 1837 | Bulk Gas Storage Facility | TBD | X | |
| 1874 | Yard Area Pools/Lining | Yard Area Pools | X | |
| 1875 | HVAC Fab & Installation | TBD | | X |

**Exhibit E – Subcontract Alignment Process and Managed Subcontracts**

| Table 1. Construction Subcontracts (Note 1) | | | | |
|---|---|---|---|---|
| **Number** | **Title/Scope Description** | **Current Subcontractor** | **Managed by Owner (Owner-Managed Subcontract)** | **Managed by Contractor (Contractor-Managed Subcontract)** |
| 1876 | HVAC Testing and Balance | TBD | | X |
| 1878 | Craft Support for MAB | CB&I Services Inc. | X (Note 2) | X (Note 2) |
| 1885 | Union - General Services | Stratton | X | |
| 1886 | Construction Air Services | NexAir | | X |
| 1888 | Heavy Civil | Williams Plant Services | X | |
| 1889 | Building 305 Excavation | C.A. Murren | X | |
| 1893 | Security Consulting | Ultimate Access | X | |
| 2092 | Diesel Generator Building U3&4 | TBD | | X |
| 2096 | Rack and Pinion Elevators | TBD | | X |
| 2097 | US Security - Unarmed Security Guards | US Security | X | |
| 2100 | Ring HVAC Duct Work Installation | CB&I | X (Note 2) | X (Note 2) |
| 2104 | Annual Fire Protection | Wolverine | X | |
| 2108 | Turbine Assembly | TurbinePro | | X |
| 2109 | Concrete Spoils Crushing | TBD | X | |
| 2113 | Building 304 | Thompson Construction Group | X | |
| 2114 | Metrology & Survey Services | API | | X |
| 2116 | New BRE for Building 304 | Safariland | X | |
| 2120 | Site Construction | Fluor Enterprises, Inc. | X | |
| 2376 | NSSS Machining and Welding Services | PCI | | X |
| 2380 | Building 305 | Thompson Construction Group | X | |
| 2551 | Transformer Pads | TBD | | X |
| 2565 | Above Ground Electrical Installation | TBD | | X |
| 2566 | Architectural Finishes | TBD | | X |
| 2567 | RWI Structure Work - Phase III | TBD | | X |
| 2588 | Permanent Plant Security System | Williams Specialty | X | |
| | | | | |

**Exhibit E – Subcontract Alignment Process and Managed Subcontracts**

| Table 1. Construction Subcontracts (Note 1) | | | | |
|---|---|---|---|---|
| **Number** | **Title/Scope Description** | **Current Subcontractor** | **Managed by Owner (Owner-Managed Subcontract)** | **Managed by Contractor (Contractor-Managed Subcontract)** |
| 2603 | Cathodic Protection | TBD | | X |
| 2604 | Computer Flooring | TBD | | X |
| 2605 | Service Water System Cooling Tower | TBD | | X |
| 2600 | Annulus Grouting | TBD | | X |
| 2601 | Gas & Communication Duct Bank | TBD | | X |
| 2602 | CWS Pipe Interior Grout PCCP Joint | TBD | | X |
| TBD | Mirror Reflective Insulation | Transco | | X |
| TBD | Toshiba TAS | Toshiba | X | |
| TBD | Site Medical Management Services | Core Medical | | X |
| TBD | Potential Scope (both Units): RV Internals , Refueling Machine, PZRHR Install | TBD | | X |
| TBD | CVAP Installation | TBD | | X |
| TBD | U3/U4 RV Head Vent & IHP | TBD | | X |
| TBD | Final Paving | TBD | X | |
| TBD | Battery Testing | TBD | X | |
| TBD | Earth Work & Erosion Control | TBD | | X |
| TBD | Shield Building Tensions Ring | TBD | | X |
| TBD | Shield Building Tank | TBD | | X |
| TBD | Demo (No Mans Land) Work | TBD | X | |
| TBD | Surveying | TBD | | X |
| TBD | NI 3&4 Fire Detection & Suppression | TBD | | X |
| TBD | Equipment - Crane Operate & Maintain Contracts | TBD | | X |
| TBD | Equipment - Crane Rental Agreements | TBD | | X |
| TBD | Equipment - General Construction Equipment Rental Agreements | TBD | | X |
| TBD | HLD Disassembly | TBD | | X |

Notes
1. This table will be updated to include all relevant purchase orders for Construction Materials required in the performance of the Work.
2. Contractor’s responsibility is limited to managing the onsite construction activities related to the CB&I subcontracts. Owners will remain responsible to manage all offsite fabrication, engineering, and other activities as may be specified and, for the foregoing purposes, the CB&I subcontracts will be treated as “Owner-Managed Subcontracts”.

**Exhibit F - Form of Letters of Credit**

**Form of Repayment Letter of Credit**

BANK

Date: ________
Letter of Credit Number: __

Beneficiary:
*Georgia Power Company, acting for itself and as agent for Oglethorpe Power Corporation (An Electric Membership Corporation), Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and The City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners*
*(address)*
*(Attn:)*

Applicant:
*Bechtel Power Corporation*
*(address)*

We, *Bank Name* , hereby establish in favor of Georgia Power Company, acting for itself and as agent for Oglethorpe Power Corporation (An Electric Membership Corporation), Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and The City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners ("Beneficiary" or "you" or "your"), at the request of and for the account of Bechtel Power Corporation ("Applicant") our Irrevocable Standby Letter of Credit No. ______ ("Letter of Credit") in the amount of [USD $ ] ( *Insert Amount in Words* ) (the "Available Amount").

We are advised that this Letter of Credit is issued with respect to that certain Construction Completion Agreement dated as of ____________, 2017 between Beneficiary and Applicant, including without limitation the Exhibits attached thereto (as amended, extended, supplemented, or restated from time to time, the "Agreement").

The Available Amount of this Letter of Credit is available to you against your executed written Drawing Certificate/Demand(s) in the form attached as Annex I hereto, with appropriate insertions (including relevant wiring instructions), presented to us. Multiple, partial demands may be made hereunder. The Available Amount of this Letter of Credit will be reduced if and as partial demands are honored; however, payments shall not in the aggregate exceed the original Available Amount (as may be increased by amendment as referenced herein).

Presentation of any such Drawing Certificate/Demand may be made on any day on or before the Expiration Date (defined below) on which we are open for business at our office located at ______________________________ ("Business Day"), Attn: _______________. Drawing Certificates/Demands under this Letter of Credit may be presented by telecopy

**Exhibit F - Form of Letters of Credit**

(“fax”) to fax number (__) ________ (after notifying us in advance by telephone at _______________) followed by the original of such Drawing Certificate/Demand, along with a copy of this Letter of Credit, dispatched by certified or registered mail, hand delivery or overnight courier service to our address above; provided it is understood that any such fax presentation shall be considered the operative presentation.

This Letter of Credit expires at the close of business at our office on ___________ (as may be extended as set forth below, the “Expiration Date”). It is a condition of this Letter of Credit that it and the Expiration Date will be deemed automatically extended without amendment for successive periods of one year each from the present or any future Expiration Date, unless we send notice to you, in writing, by certified or registered mail or courier service at your address above not less than sixty (60) days prior to any such Expiration Date, that we have elected not to extend such Expiration Date for such additional period. This Letter of Credit will be considered as null and void after the Expiration Date even if the original Letter of Credit is not returned to us, or upon return to us by Beneficiary of this Letter of Credit for cancellation prior to the Expiration Date.

This Letter of Credit sets forth in full the terms of our undertaking, and such undertaking shall not be modified, annulled or amplified by reference to the Agreement or any other agreement referred to herein or in which this Letter of Credit is referred or to which this Letter of Credit relates, and any such reference shall not be deemed to incorporate herein by reference the Agreement or any other agreement. Our obligations hereunder are primary obligations that shall not be affected by the performance or non-performance by Applicant or you of any obligations under the Agreement or under any other agreement between Applicant and Beneficiary or between Applicant and us or between Applicant and its agents.

Our obligation under this Letter of Credit is our individual obligation and is in no way contingent upon reimbursement with respect thereto.

The Available Amount under this Letter of Credit may be increased by means of an amendment only or decreased by means of (i) an amendment or (ii) payment demands honored hereunder.

All fees associated with this Letter of Credit (other than transfer charges and fees as described below) are for Applicant’s account.

We will honor in our own funds each Drawing Certificate/Demand presented to us in compliance with the terms of this Letter of Credit within three (3) Business Days after presentation.

This Letter of Credit is transferrable, but only in its entirety, and may be successively transferred. Transfer of this Letter of Credit shall be effected by us upon your submission of this original Letter of Credit, including all amendments, if any, accompanied by a duly completed and signed Transfer Request Form in the form of Annex II, with the signature thereon authenticated by your bank. In any event, this Letter of Credit may not be transferred to any person or entity listed in or otherwise subject to, any sanction or embargo under any applicable restrictions. Charges and fees related to such transfer will be for the account of the Beneficiary.

We are subject to various laws, regulations and executive and judicial orders (including economic sanctions, embargoes, anti-boycott, anti-money laundering, anti-terrorism, and

**Exhibit F - Form of Letters of Credit**

anti-drug trafficking laws and regulations) of the U.S. and other countries that are enforceable under applicable law. We will not be liable for our failure to make, or our delay in making, payment under this Letter of Credit or for any other action we take or do not take, or any disclosure we make, under or in connection with this Letter of Credit (including, without limitation, any refusal to transfer this Letter of Credit) that is required by such laws, regulations, or orders.

To the extent not contrary to the express terms hereof, this Letter of Credit is subject to the International Standby Practices (ISP98), International Chamber of Commerce Publication No. 590, and, as to matters not governed by ISP98, this Letter of Credit shall be governed by, and construed in accordance with, the laws of the State of New York, without regard to principles of conflict of laws.

[Bank Seal, Insert day, month, year]

**Exhibit F - Form of Letters of Credit**

## ANNEX I

## DRAWING CERTIFICATE/DEMAND

To: [BANK NAME AND ADDRESS]

RE: Irrevocable Standby Letter of Credit No. ________________ dated ________ ____, _____

Reference is made to that certain Irrevocable Standby Letter of Credit No. _______________ ("Letter of Credit") issued by [ *Issuing Bank* ] (the "Bank") in favor of Georgia Power Company, acting for itself and as agent for Oglethorpe Power Corporation (An Electric Membership Corporation), Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and The City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners ("Beneficiary").

Reference also is made to the Construction Completion Agreement dated _______________ __, 2017 by and between Beneficiary and Bechtel Power Corporation ("Applicant"), including without limitation the Exhibits attached thereto (as amended, extended, supplemented, or restated from time to time, the "Agreement"). The Beneficiary hereby certifies to Bank that [ *insert one of the following sentences* ]:

> Applicant has failed to make payment of amount(s) and applicable interest totaling not less than the Demanded Amount (defined below) as and when required under the Agreement.

or

> Applicant is required to maintain a letter of credit under the Agreement and the Expiration Date of the Letter of Credit is forty-six (46) or fewer days from the date hereof and a substitute or replacement letter of credit that satisfies the requirements of the Agreement as to form, issuer and amount has not been provided to Beneficiary.

Beneficiary demands payment of $_________ (the "Demanded Amount") under the Letter of Credit in immediately available funds by wire transfer to the following account:

[Account Information]

**Exhibit F - Form of Letters of Credit**

In witness whereof, the Beneficiary has executed and delivered this Drawing Certificate/Demand as of this ____ day of __________, 20__.

**BENEFICIARY**

Georgia Power Company, acting for itself and as agent for
Oglethorpe Power Corporation (An Electric Membership
Corporation), Municipal Electric Authority of Georgia,
MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC,
MEAG Power SPVP, LLC, and The City of Dalton,
Georgia, acting by and through its Board of Water,
Light and Sinking Fund Commissioners

By: ____________
Name: ___________________________
Title: ___________________________

**Exhibit F - Form of Letters of Credit**

**ANNEX II**

**TRANSFER REQUEST FORM**

(COMPANY LETTERHEAD)

TO: [Bank Name and Address]

DATE: _________________

RE: Your Irrevocable Standby Letter of Credit No. ____________issued on _______________ in favor of the undersigned.

Gentlemen:

For value received, the undersigned Beneficiary hereby irrevocably transfers, in its entirety, all rights to draw under the above referenced Irrevocable Standby Letter of Credit to:

______________________________
The "Transferee"

______________________________
Address
______________________________
______________________________

All rights of the Beneficiary in the Irrevocable Standby Letter of Credit, are transferred to the above Transferee, who shall hereafter be the Beneficiary for all purposes and the Beneficiary shall have no further rights thereunder, including rights relating to any amendments of the stated amount of the Irrevocable Standby Letter of Credit or to the expiry date or other amendments, and whether now existing or hereafter made. All amendments are to be advised directly to the Transferee without necessity of any consent of or notice to the Beneficiary.

The original Irrevocable Standby Letter of Credit is returned herewith, and the Beneficiary hereby requests the authorized Bank to endorse the transfer on the reverse thereof and forward it directly to the Transferee with the Issuing Bank's customary notice of transfer.

(together with your request for transfer, please enclose your check for $700.00, unless otherwise arranged)

Very Truly Yours

(COMPANY NAME)

BY: __________________________
AUTHORIZED SIGNATURE
(NAME PRINTED)
AS ITS: _______________________

**Exhibit F - Form of Letters of Credit**

TITLE

THE PERSON WHOSE NAME AND SIGNATURE APPEARS HEREWITH IS A DULY AUTHORIZED SIGNATURE OF THE BENEFICIARY:

NAME OF BANK (WITH BANK STAMP OR SEAL)

______________________________
SIGNATURE OF BANK OFFICER

TITLE:________________________

**Exhibit F - Form of Letters of Credit**

**Form of Owner Letter of Credit**

BANK

Date: ________
Letter of Credit Number: __

Beneficiary:
*Bechtel Power Corporation*
*(address)*

Applicant:
[ *Owner* ]
[ *Address* ]

We, *Bank Name* , hereby establish in favor of Bechtel Power Corporation (“Beneficiary” or “you” or “your”), at the request of and for the account of [ *Owner* ] (“Applicant”) our Irrevocable Standby Letter of Credit No. ______ (“Letter of Credit”) in the amount of [USD $ ] ( *Insert Amount in Words* ) (the “Available Amount”).

We are advised that this Letter of Credit is issued with respect to that certain Construction Completion Agreement dated as of ____________, 2017 between Georgia Power Company, acting for itself and as agent for Oglethorpe Power Corporation (An Electric Membership Corporation), Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and The City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, and Beneficiary, including without limitation the Exhibits attached thereto (as amended, extended, supplemented, or restated from time to time, the “Agreement”).

The Available Amount of this Letter of Credit is available to you against your executed written Drawing Certificate/Demand(s) in the form attached as Annex I hereto, with appropriate insertions (including relevant wiring instructions), presented to us. Multiple, partial demands may be made hereunder. The Available Amount of this Letter of Credit will be reduced if and as partial demands are honored; however, payments shall not in the aggregate exceed the original Available Amount (as may be increased by amendment as referenced herein).

Presentation of any such Drawing Certificate/Demand may be made on any day on or before the Expiration Date (defined below) on which we are open for business at our office located at ______________________________ (“Business Day”), Attn: _______________. Drawing Certificates/Demands under this Letter of Credit may be presented by telecopy (“fax”) to fax number (__) ________ (after notifying us in advance by telephone at _______________) followed by the original of such Drawing Certificate/Demand, along with a copy of this Letter of Credit, dispatched by certified or registered mail, hand delivery or overnight courier service to our address above; provided it is understood that any such fax presentation shall be considered the operative presentation.

This Letter of Credit expires at the close of business at our office on ___________ (as may be extended as set forth below, the “Expiration Date”). It is a condition of this Letter of

Credit that it and the Expiration Date will be deemed automatically extended without amendment for successive periods of one year each from the present or any future Expiration Date, unless we send notice to you, in writing, by certified or registered mail or courier service, at your address above not less than sixty (60) days prior to any such Expiration Date, that we have elected not to extend such Expiration Date for such additional period. This Letter of Credit will be considered as null and void after the Expiration Date even if the original Letter of Credit is not returned to us, or upon return to us by Beneficiary of this Letter of Credit for cancellation prior to the Expiration Date.

This Letter of Credit sets forth in full the terms of our undertaking, and such undertaking shall not be modified, annulled or amplified by reference to the Agreement or any other agreement referred to herein or in which this Letter of Credit is referred or to which this Letter of Credit relates, and any such reference shall not be deemed to incorporate herein by reference the Agreement or any other agreement. Our obligations hereunder are primary obligations that shall not be affected by the performance or non-performance by Applicant or you of any obligations under the Agreement or under any other agreement between Applicant and you or between Applicant and us or between Applicant and its agents.

Our obligation under this Letter of Credit is our individual obligation and is in no way contingent upon reimbursement with respect thereto.

The Available Amount under this Letter of Credit may be increased by means of an amendment only or decreased by means of (i) an amendment or (ii) payment demands honored hereunder.

All fees associated with this Letter of Credit (other than transfer charges and fees as described below) are for Applicant's account.

We will honor in our own funds each Drawing Certificate/Demand presented to us in compliance with the terms of this Letter of Credit within three (3) Business Days after presentation.

This Letter of Credit is transferrable, but only in its entirety, and may be successively transferred. Transfer of this Letter of Credit shall be effected by us upon your submission of this original Letter of Credit, including all amendments, if any, accompanied by a duly completed and signed Transfer Request Form in the form reasonably requested by us, with the signature thereon authenticated by your bank. In any event, this Letter of Credit may not be transferred to any person or entity listed in or otherwise subject to, any sanction or embargo under any applicable restrictions. Charges and fees related to such transfer will be for the account of the Beneficiary.

We are subject to various laws, regulations and executive and judicial orders (including economic sanctions, embargoes, anti-boycott, anti-money laundering, anti-terrorism, and anti-drug trafficking laws and regulations) of the U.S. and other countries that are enforceable under applicable law. We will not be liable for our failure to make, or our delay in making, payment under this Letter of Credit or for any other action we take or do not take, or any disclosure we make, under or in connection with this Letter of Credit (including, without limitation, any refusal to transfer this Letter of Credit) that is required by such laws, regulations, or orders.

**Exhibit F - Form of Letters of Credit**

To the extent not contrary to the express terms hereof, this Letter of Credit is subject to the International Standby Practices (ISP98), International Chamber of Commerce Publication No. 590, and, as to matters not governed by ISP98, this Letter of Credit shall be governed by, and construed in accordance with, the laws of the State of New York, without regard to principles of conflict of laws.

[Bank Seal, Insert day, month, year]

**Exhibit F - Form of Letters of Credit**

**ANNEX I**

**DRAWING CERTIFICATE/DEMAND**

To: [BANK NAME AND ADDRESS]

RE: Irrevocable Standby Letter of Credit No. ________________ dated ________ ____, _____

Reference is made to that certain Irrevocable Standby Letter of Credit No. _______________ ("Letter of Credit") issued by [ *Issuing Bank* ] (the "Bank") in favor of Bechtel Power Corporation ("Beneficiary") upon the application of [ *Owner* ] ("Applicant").

Reference also is made to the Construction Completion Agreement dated _______________ __, 2017 by and between Georgia Power Company, acting for itself and as agent for Oglethorpe Power Corporation (An Electric Membership Corporation), Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and The City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, and Beneficiary, including without limitation the Exhibits attached thereto (as amended, extended, supplemented, or restated from time to time, the "Agreement"). The Beneficiary hereby certifies to Bank that [ *insert one of the following sentences* ]:

> Applicant has failed to make payment of amount(s) totaling not less than the Demanded Amount (defined below) as and when due pursuant to the Agreement.

or

> The Expiration Date of the Letter of Credit is forty-six (46) or fewer days from the date hereof, Applicant is required to maintain a letter of credit under the Agreement, and Beneficiary has received neither cash security nor a substitute or replacement letter of credit that satisfies the requirements of the Agreement as to form, issuer and amount.

Beneficiary demands payment of $_________ (the "Demanded Amount") under the Letter of Credit in immediately available funds by wire transfer to the following account:

[Account Information]

**Exhibit F - Form of Letters of Credit**

In witness whereof, the Beneficiary has executed and delivered this Drawing Certificate/Demand as of this ____ day of __________, 20__.

**BENEFICIARY**

Bechtel Power Corporation

By: _____________
Name: _____________________________
Title: _____________________________

# Exhibit G – Mechanical Completion

Mechanical Completion is defined as the state of construction completion of a Unit such that the Unit is ready for Hot Functional Testing (HFT). Specifically, subject to Punch List items, Mechanical Completion shall be achieved upon completion of Contractor's physical construction and/or installation activities and Contractor's construction testing activities (to the extent identified as Contractor's responsibility in Table 2 below) for those systems, sub-systems, equipment, and components of a Unit that are within the boundaries of those Boundary Identification Packages (BIPs) needed to support HFT of the Unit.

Table 1 identifies those BIPs that are needed to support HFT such that the Unit is ready for HFT and those that are not. Table 2 identifies the division of responsibility for construction testing activities.

**Table 1. Boundary Identification Packages as of September 2017 (Unit 3 and Unit 4 Identical)**

| System Designator | System | BIPs Needed to Support Hot Functional Testing | BIPs Not Needed to Support Hot Functional Testing |
|---|---|---|---|
| ASS | Auxiliary Steam Supply System | ASS-01, ASS-02 | None |
| BDS | Steam Generator Blowdown System | BDS-01, BDS-02, BDS-03, BDS-04 | None |
| BIS | Business Infrastructure System | (Note 2) | BIS-01, BIS-02, BIS-03, BIS-04, BIS-05 |
| CAS | Compressed and Instrument Air Systems | CAS-01, CAS-02, CAS-03, CAS-04, CAS-05, CAS-06, CAS-07, CAS-08, CAS-09, CAS-10, CAS-11, CAS-12, CAS-13, CAS-14, CAS-15, CAS-16 | None |
| CCS | Component Cooling Water System | CCS-01, CCS-02, CCS-03 | None |
| CDS | Condensate System | CDS-01, CDS-02, CDS-03, CDS-04 | None |
| CES | Condenser Tube Cleaning System | CES-01 | None |
| CFS | Turbine Island Chemical Feed System | CFS-01, CFS-02, CFS-03, CFS-04, CFS-05, CFS-06, CFS-07, CFS-08, CFS-09 | None |
| CMS | Condenser Air Removal System | CMS-01 | None |
| CNS | Containment System | None required for HFT. | CNS-01 |
| CPS | Condensate Polishing System | CPS-01 | None |
| CVS | Chemical and Volume Control System | CVS-01, CVS-02, CVS-03, CVS-04 | None |
| CWS | Circulating Water System | CWS-01, CWS-02, CWS-03 | None |
| CYS | Cyber Security System | (Note 2) | (Note 2) |
| | | | |

**Exhibit G – Mechanical Completion**

**Table 1. Boundary Identification Packages as of September 2017 (Unit 3 and Unit 4 Identical)**

| System Designator | System | BIPs Needed to Support Hot Functional Testing | BIPs Not Needed to Support Hot Functional Testing |
|---|---|---|---|
| DAS | Diverse Actuation System | DAS-01 | None |
| DDS | Data Display and Processing System | DDS-01, DDS-02, DDS-03, DDS-04, DDS-05, DDS-06, DDS-07, DDS-08, DDS-09, DDS-10, DDS-11, DDS-12 | None |
| DOS | Standby Diesel Fuel Oil System | DOS-01, DOS-02, DOS-03 | None |
| DRS | Storm Drain System | None required for HFT. | DRS-01 |
| DTS | Demineralized Water Treatment System | DTS-01 | None |
| DWS | Demineralized Water Transfer and Storage System | DWS-01, DWS-02, DWS-03, DWS-04, DWS-05 | None |
| ECS | Main ac Power System | ECS-01, ECS-02, ECS-03, ECS-04, ECS-05, ECS-06, ECS-07, ECS-08, ECS-09, ECS-10, ECS-11, ECS-12, ECS-13, ECS-14, ECS-15, ECS-16, ECS-17, ECS-18, ECS-19, ECS-20 | None |
| EDS | Non Class 1E dc and UPS System | EDS-01, EDS-02, EDS-03, EDS-04, EDS-05, EDS-06, EDS-07, EDS-08, EDS-09, EDS-11 | SV0-EDS-11 (Note 1) |
| EFS | Communication Systems | (Note 2) | EFS-01, EFS-02, EFS-03, EFS-04, EFS-05, EFS-06, EFS-07 |
| EGS | Grounding and Lightning Protection System | EGS-01 | None |
| EHS | Special Process Heat Tracing System | None required for HFT. | EHS-01, EHS-02, EHS-03, EHS-04, EHS-05, SV0-EHS-06 (Note 1) |
| ELS | Plant Lighting System | ELS-01, ELS-02, ELS-03, ELS-04, ELS-05, ELS-06, ELS-07 | None |
| EQS | Cathodic Protection System | None required for HFT. | EQS-01 |
| FHS | Fuel Handling and Refueling System | None required for HFT. | FHS-01, FHS-02 |
| FPS | Fire Protection System | FPS-01, FPS-02, FPS-03, FPS-04, FPS-05, FPS-06, FPS-07, FPS-08, FPS-16, | None |

**Exhibit G – Mechanical Completion**

| Table 1. Boundary Identification Packages as of September 2017 (Unit 3 and Unit 4 Identical) | | | |
|---|---|---|---|
| **System Designator** | **System** | **BIPs Needed to Support Hot Functional Testing** | **BIPs Not Needed to Support Hot Functional Testing** |
| | | FPS-17, FPS-18, FPS-19, FPS-20, FPS-21, FPS-22, FPS-28, FPS-29 | |
| FWS | Main and Startup Feedwater System | FWS-01, FWS-02 | None |
| GSS | Gland Seal System | GSS-01 | None |
| HCS | Generator Hydrogen and CO2 Systems | HCS-01 | None |
| HDS | Heater Drain System | HDS-01 | None |
| HSS | Hydrogen Seal Oil System | HSS-01 | None |
| IDS | Class 1E dc and UPS System | IDS-01, IDS-02, IDS-03, IDS-04, IDS-05, IDS-06, IDS-07, IDS-08, IDS-09, IDS-10 | None |
| IIS | In-core Instrumentation System | IIS-01 | None |
| LOS | Main Turbine and Generator Lube Oil System | LOS-01, LOS-02 | None |
| MES | Meteorological and Environmental Monitoring System | None required for HFT. | MES-01 |
| MHS | Mechanical Handling System | None required for HFT. | MHS-01, MHS-02, MHS-03, MHS-04, MHS-05, MHS-06, MHS-07, MHS-08, MHS-09 |
| MSS | Main Steam System | MSS-01, MSS-02 | None |
| MTS | Main Turbine System | MTS-01 | None |
| NCS | Network Connection System | (Note 2) | NCS-01, NCS-02, NCS-03, NCS-04, NCS-05, NCS-06, NCS-07, NCS-08 |
| OCS | Operation and Control Centers System | OCS-01, OCS-02 | None |
| PCS | Passive Containment Cooling System | None required for HFT. | PCS-01, PCS-02 |
| PGS | Plant Gas Systems | PGS-01, PGS-02, PGS-03, PGS-04, PGS-05 | None |
| PLS | Plant Control System | PLS-01, PLS-02, PLS-03, PLS-04, PLS-05, PLS-06, PLS-07, PLS-08, PLS-09, PLS-10, PLS-11, PLS-12, PLS-13, PLS-14, PLS-15, PLS-16, PLS-17, PLS-18, PLS-19, PLS-20, PLS-21, PLS-22, PLS-23, PLS-24, PLS-25, PLS-26, PLS-27 | None |

## Exhibit G – Mechanical Completion

| Table 1. Boundary Identification Packages as of September 2017 (Unit 3 and Unit 4 Identical) | | | |
|---|---|---|---|
| **System Designator** | **System** | **BIPs Needed to Support Hot Functional Testing** | **BIPs Not Needed to Support Hot Functional Testing** |
| | | PLS-10, PLS-11, PLS-12, PLS-13, PLS-14, PLS-15, PLS-16, PLS-17, PLS-18, PLS-19, PLS-20, PLS-21, PLS-22, PLS-23, PLS-24, PLS-25, PLS-26, PLS-27 | |
| PMS | Protection and Safety Monitoring System | PMS-01, PMS-02, PMS-03, PMS-04, PMS-05 | None |
| PSS | Primary Sampling System | PSS-01 | None |
| PWS | Potable Water System | PWS-02, PWS-03, PWS-04, PWS-05, PWS-06, PWS-07, PWS-08 | SV0-PWS-01 (Note 1) |
| PXS | Passive Core Cooling System | PXS-01, PXS-02, PXS-03 | None |
| RCS | Reactor Coolant System | RCS-01, RCS-02, RCS-03, RCS-04, RCS-05, RCS-06, RCS-07 | None |
| RDS | Gravity and Roof Drain Collection System | None required for HFT. | RDS-01 |
| RMS | Radiation Monitoring System | RMS-01, RMS-02, RMS-03, RMS-04, RMS-05 | None |
| RNS | Normal Residual Heat Removal System | RNS-01 | None |
| RWS | Raw Water System | RWS-02, RWS-03 | SV0-RWS-01 (Note 1) |
| RXS | Reactor System | RXS-01, RXS-02, RXS-03 | None |
| SDS | Sanitary Drainage System | None required for HFT. | SDS-01 |
| SES | Plant Security System | None required for HFT. | SES-01 |
| SFS | Spent Fuel Pit Cooling System | SFS-01, SFS-02, SFS-03 | None |
| SGS | Steam Generator System | SGS-01, SGS-02 | None |
| SJS | Seismic Monitoring System | None required for HFT. | SJS-01 |
| SMS | Special Monitoring System | SMS-01 | None |
| SSS | Secondary Sampling System | SSS-01 | None |
| SWS | Service Water System | SWS-01 | None |
| TCS | Turbine Building Closed Cooling Water System | TCS-01, TCS-02 | None |
| TDS | Turbine Island Vents, Drains and Relief System | (Note 2) | None |

## Exhibit G – Mechanical Completion

| Table 1. Boundary Identification Packages as of September 2017 (Unit 3 and Unit 4 Identical) | | | |
|---|---|---|---|
| **System Designator** | **System** | **BIPs Needed to Support Hot Functional Testing** | **BIPs Not Needed to Support Hot Functional Testing** |
| TOS | Main Turbine Control and Diagnostics System | TOS-01 | None |
| TVS | Closed Circuit TV System | None required for HFT. | TVS-01 |
| VAS | Radiologically Controlled Area Ventilation System | VAS-01, VAS-02, VAS-03 | None |
| VBS | Nuclear Island Nonradioactive Ventilation System | VBS-01, VBS-02, VBS-03, VBS-04 | VBS-05 |
| VCS | Containment Recirculation Cooling System | VCS-01 | None |
| VES | Main Control Room Emergency Habitability System | VES-01 | None |
| VFS | Containment Air Filtration System | VFS-01 (Note 2) | None |
| VHS | Health Physics and Hot Machine Shop HVAC System | None required for HFT. | VHS-01 |
| VLS | Containment Hydrogen Control System | None required for HFT. | VLS-01 |
| VRS | Radwaste Building HVAC System | None required for HFT. | VRS-01 |
| VTS | Turbine Building Ventilation System | VTS-01, VTS-02, VTS-03, VTS-04, VTS-05, VTS-06, VTS-07, VTS-08, VTS-09, VTS-10 | None |
| VUS | Containment Leak Rate Test System | None required for HFT. | VUS-01 |
| VWS | Central Chilled Water System | VWS-01, VWS-02, VWS-03, VWS-04, VWS-05, VWS-06, VWS-07 | None |
| VXS | Annex/Auxiliary Non-Radioactive Ventilation System | VXS-01, VXS-02, VXS-03, VXS-04, VXS-05 | None |
| VYS | Hot Water Heating System | VYS-01, VYS-02, VYS-03 | None |
| VZS | Diesel Generator Building Ventilation System | VZS-01 | None |
| WGS | Gaseous Radwaste System | WGS-01 | None |
| WLS | Liquid Radwaste System | WLS-01, WLS-02, WLS-04, WLS-05, WLS-06, WLS-07, WLS-08, WLS-09, WLS-10, WLS-11 | WLS-03 |

**Exhibit G – Mechanical Completion**

| Table 1. Boundary Identification Packages as of September 2017 (Unit 3 and Unit 4 Identical) | | | |
|---|---|---|---|
| **System Designator** | **System** | **BIPs Needed to Support Hot Functional Testing** | **BIPs Not Needed to Support Hot Functional Testing** |
| WRS | Radioactive Waste Drain System | WRS-01, WRS-02, WRS-03 | None |
| WSS | Solid Radwaste System | WSS-01 | None |
| WWS | Waste Water System | WWS-01, WWS-02, WWS-03, WWS-04, WWS-05, WWS-06, WWS-07, WWS-08, WWS-09 | None |
| YFS | Yard Fire Water System | (Note 2) | SV0-YFS-01 (Note 1) |
| ZAS | Main Generation System | ZAS-01, ZAS-02 | None |
| ZBS | Transmission Switchyard and Offsite Power System | None required for HFT (Notes 2 and 3) | None |
| ZFS | Offsite Communication System | None required for HFT. | ZFS-01 |
| ZOS | Onsite Standby Power System | ZOS-01, ZOS-02 | None |
| ZRS | Offsite Retail Power System | ZRS-03 | SV0-ZRS-01 (Note 1), SV0-ZRS-02 (Note 1), SV0-ZRS-04 (Note 1) |
| ZVS | Excitation and Voltage Regulation System | ZVS-01 (Note 2) | None |

Notes

1. Turnover for this BIP has already been completed as part of the Building 315 turnover and is not Contractor scope.
2. The portions of this system needed for HFT have not yet been determined.
3. This system is Owners' scope.

**Exhibit G – Mechanical Completion**

| Table 2. Construction Testing Division of Responsibility | | | |
|---|---|---|---|
| **Item** | **Test Description** | **Contractor Responsibility** | **Owner Responsibility** |
| 1 | Perform non-destructive testing (e.g., RT, UT, PT)<br>(via Contractor-Managed Subcontract) | X | |
| 2 | Remove construction blinds | X | |
| 3 | Clean and inspect piping and equipment | X | |
| 4 | Perform pipe line specification flushing and cleanliness verification | X | |
| 5 | Perform pipe line pressure testing | X | |
| 6 | Inspect and stroke manual valves | X | |
| 7 | Release piping hangers and heat exchanger expansion bolts | X | |
| 8 | Perform initial set of spring type pipe hangers | X | |
| 9 | Perform ASME code pressure tests | X | |
| 10 | Perform process fluid system flushing (e.g., turbine lube oil flushes, chemical and volume control system flushing, reactor coolant system flushing) | | X |
| 11 | Perform reactor coolant system and steam generator system hydrostatic testing | | X |
| 12 | Inspect and close-up vessels | X | |
| 13 | Perform rotating equipment alignment | X | |
| 14 | Service, adjust, lubricate, maintain equipment<br>(prior to Contractor turnover to Owner) | X | |
| 15 | Inspect wiring, cable runs, and accessories | X | |
| 16 | Perform high potential, megger, and cable continuity testing of cables and equipment | X | |
| 17 | Inspect switchgear and mechanical interlocks | X | |
| 18 | Install and service batteries | X | |
| 19 | Calibrate instruments and sensors | | X |
| 20 | Service and fill transformers | | X |
| 21 | Perform electrical checks and calibrations | | X |
| 22 | Perform energized component, loop, and system tests | | X |

**Exhibit H – Form of Monthly Status Report**

The table of contents for Contractor's Monthly Status Report is provided below. Changes to the table of contents will be mutually agreed by the Parties.

1. Executive Summary

    - Progress Summary
    - Critical Issues Summary
    - Overall Staffing Summary

2. Safety Status

3. Quality Status

4. Construction Progress (Overall and By Area)

    - Overall Construction Summary
    - Key Milestones Achieved/Work in Progress
    - Key Work Planned to Start Next Month
    - Construction Equipment Summary (Needs/Concerns)
    - System Turnover (Future)

5. Schedule Performance (Overall and By Area)

    - Construction Forecast Summary
    - Percent Complete Analysis/Summary
    - Critical Path Analysis/Summary
    - Key Schedule Issues/Concerns

6. Cost Performance

    - Construction Forecast Summary
    - Trend/Change Order Summary
        - Approved Trends this Month
        - Key Potential Pending Trends/Changes
    - Cost Expenditure Summary and Analysis
    - Field Procurement and Subcontracts
    - Contingency Summary
    - Invoice and Payment Status

7. Managed-Subcontracts Status

    - Overall Summary
    - Cost Summary and Analysis
    - Schedule Summary and Analysis

8. Issues and Concerns

**Exhibit H – Form of Monthly Status Report**

Attachments

- Critical Action Items Report
- Monthly Cost Report
- Project Percent Complete Curves
- Working Schedule
- Bulk Commodity Curves
- Scorecard (reflecting production, productivity, and schedule performance at the unit/building/commodity level of detail)
- Craft Staffing and Jobhours
- Field Non-Manual Staffing and Jobhours
- Scope Change Log
- Monthly Trend Report
- Progress Photos

**Exhibit I – Key Personnel / Lead Personnel**

**KEY PERSONNEL**

Bechtel

- Project Manager
- Site Manager
- Construction Project Controls Manager
- Procurement & Contracts Manager
- Quality Control Manager
- Chief Project Field Engineering Manager
- Unit 3 Construction Manager
- Unit 4 Construction Manager
- Balance of Plant Area Manager
- Field Subcontracts Manager
- Environmental, Safety, and Health Manager

Richmond County Constructors, LLC (Subcontractor)

- Manager

**LEAD PERSONNEL**

Bechtel

- Deputy Project Controls Manager
- Unit 3 Project Field Engineer
- Unit 4 Project Field Engineer
- Central Services Project Field Engineer
- Unit 3 Day Shift Unit Manager
- Unit 4 Day Shift Unit Manager
- Unit 3 Night Shift Unit Manager
- Unit 4 Night Shift Unit Manager
- Unit 3 Day Shift Auxiliary Building Area Manager
- Unit 4 Day Shift Auxiliary Building Area Manager
- Construction Infrastructure Manager
- Construction Issues Manager
- Turnover Group Manager
- Unit 3 Day Shift Shield Building Area Manager
- Unit 4 Day Shift Shield Building Area Manager
- Unit 3 Day Shift Containment Area Manager
- Unit 4 Day Shift Containment Area Manager
- Unit 3 Day Shift Turbine Island Area Manager
- Unit 4 Day Shift Turbine Island Area Manager
- Unit 3 Day Shift Annex/ Rad Waste Building Area Manager
- Unit 4 Day Shift Annex/ Rad Waste Building Area Manager

Richmond County Constructors, LLC (Subcontractor)

- Deputy Manager

**EXHIBIT J-1**

**DAVIS-BACON ACT REQUIRED PROVISIONS**

**ARTICLE 34. SECTION (a) MINIMUM WAGES, ETC.**

**(1) Minimum wages.**

(i) All laborers and mechanics employed or working upon the site of the work (or under the United States Housing Act of 1937 or under the Housing Act of 1949 in the construction or development of the project), will be paid unconditionally and not less often than once a week, and without subsequent deduction or rebate on any account (except such payroll deductions as are permitted by regulations issued by the Secretary of Labor under the Copeland Act (29 CFR part 3)), the full amount of wages and bona fide fringe benefits (or cash equivalents thereof) due at time of payment computed at rates not less than those contained in the wage determination of the Secretary of Labor which is attached hereto and made a part hereof, regardless of any contractual relationship which may be alleged to exist between the contractor and such laborers and mechanics.

Contributions made or costs reasonably anticipated for bona fide fringe benefits under section 1 (b)(2) of the Davis-Bacon Act on behalf of laborers or mechanics are considered wages paid to such laborers or mechanics, subject to the provisions of paragraph (a)(l)(iv) of this section; also, regular contributions made or costs incurred for more than a weekly period (but not less often than quarterly) under plans, funds, or programs which cover the particular weekly period, are deemed to be constructively made or incurred during such weekly period. Such laborers and mechanics shall be paid the appropriate wage rate and fringe benefits on the wage determination for the classification of work actually performed, without regard to skill, except as provided in Sec. 5.5(a)(4) [paragraph (a)(4) below]. Laborers or mechanics performing work in more than one classification may be compensated at the rate specified for each classification for the time actually worked therein: Provided, That the employer's payroll records accurately set forth the time spent in each classification in which work is performed. The wage determination (including any additional classification and wage rates conformed under paragraph (a)(l)(ii) of this section) and the Davis-Bacon poster (WH-1321) shall be posted at all times by the contractor and its subcontractors at the site of the work in a prominent and accessible place where it can be easily seen by the workers.

(ii)(A) The contracting officer shall require that any class of laborers or mechanics, including helpers, which is not listed in the wage determination and which is to be employed under the contract shall be classified in conformance with the wage determination. The contracting officer shall approve an additional classification and wage rate and fringe benefits therefore only when the following criteria have been met:

(1) The work to be performed by the classification requested is not performed by a classification in the wage determination; and

(2) The classification is utilized in the area by the construction industry; and
(3) The proposed wage rate, including any bona fide fringe benefits, bears a reasonable relationship to the wage rates contained in the wage determination.

(ii)(B) If the contractor and the laborers and mechanics to be employed in the classification (if known), or their representatives, and the contracting officer agree on the classification and wage rate (including the amount designated for fringe benefits where appropriate), a report of the action taken shall be sent by the contracting officer to the Administrator of the Wage and Hour Division, Employment Standards Administration, U.S. Department of Labor, Washington, DC 20210. The Administrator, or an authorized representative, will approve, modify, or disapprove every additional classification action within 30 days of receipt and so advise the contracting officer or will notify the contracting officer within the 30-day period that additional time is necessary.

(ii)(C) In the event the contractor, the laborers or mechanics to be employed in the classification or their representatives, and the contracting officer do not agree on the proposed classification and wage rate (including the amount designated for fringe benefits, where appropriate), the contracting officer shall refer the questions, including the views of all interested parties and the recommendation of the contracting officer, to the Administrator for determination. The Administrator, or an authorized representative, will issue a determination within 30 days of receipt and so advise the contracting officer or will notify the contracting officer within the 30-day period that additional time is necessary.

(ii)(D) The wage rate (including fringe benefits where appropriate) determined pursuant to paragraphs (a)(1)(ii) (B) or (C) of this section, shall be paid to all workers performing work in the classification under this contract from the first day on which work is performed in the classification.

(iii) Whenever the minimum wage rate prescribed in the contract for a class of laborers or mechanics includes a fringe benefit which is not expressed as an hourly rate, the contractor shall either pay the benefit as stated in the wage determination or shall pay another bona fide fringe benefit or an hourly cash equivalent thereof.

(iv) If the contractor does not make payments to a trustee or other third person, the contractor may consider as part of the wages of any laborer or mechanic the amount of any costs reasonably anticipated in providing bona fide fringe benefits under a plan or program, Provided, That the Secretary of Labor has found, upon the written request of the contractor, that the applicable standards of the Davis-Bacon Act have been met. The Secretary of Labor may require the contractor to set aside in a separate account assets for the meeting of obligations under the plan or program.

**(2) Withholding.**

The Department of Energy ("DOE") shall upon its own action or upon written request of an authorized representative of the Department of Labor withhold or cause to be withheld

from the contractor under this contract or any other Federal contract with the same prime contractor, or any other federally-assisted contract subject to Davis-Bacon prevailing wage requirements, which is held by the same prime contractor, so much of the accrued payments or advances as may be considered necessary to pay laborers and mechanics, including apprentices, trainees, and helpers, employed by the contractor or any
subcontractor the full amount of wages required by the contract. In the event of failure to pay any laborer or mechanic, including any apprentice, trainee, or helper, employed or working on the site of the work (or under the United States Housing Act of 1937 or under the Housing Act of 1949 in the construction or development of the project), all or part of the wages required by the contract, DOE may, after written notice to the contractor, sponsor, applicant, or owner, take such action as may be necessary to cause the suspension of any further payment, advance, or guarantee of funds until such violations have ceased.

**(3) Payrolls and basic records.**

(i) Payrolls and basic records relating thereto shall be maintained by the contractor during the course of the work and preserved for a period of three years thereafter for all laborers and mechanics working at the site of the work (or under the United States Housing Act of 1937, or under the Housing Act of 1949, in the construction or development of the project). Such records shall contain the name, address, and social security number of each such worker, his or her correct classification, hourly rates of wages paid (including rates of contributions or costs anticipated for bona fide fringe benefits or cash equivalents thereof of the types described in section 1(b)(2)(B) of the Davis-Bacon Act), daily and weekly number of hours worked, deductions made and actual wages paid. Whenever the Secretary of Labor has found under 29 CFR 5.5(a)(1)(iv) that the wages of any laborer or mechanic include the amount of any costs reasonably anticipated in providing benefits under a plan or program described in section 1(b)(2)(B) of the Davis-Bacon Act, the contractor shall maintain records which show that the commitment to provide such benefits is enforceable, that the plan or program is financially responsible, and that the plan or program has been communicated in writing to the laborers or mechanics affected, and records which show the costs anticipated or the actual cost incurred in providing such benefits. Contractors employing apprentices or trainees under approved programs shall maintain written evidence of the registration of apprenticeship programs and certification of trainee programs, the registration of the apprentices and trainees, and the ratios and wage rates prescribed in the applicable programs.

(ii)(A) The contractor shall submit weekly for each week in which any contract work is performed a copy of all payrolls to the DOE) if the agency is a party to the contract, but if the agency is not such a party, the contractor will submit the payrolls to the applicant, sponsor, or owner, as the case may be, for transmission to DOE. The payrolls submitted shall set out accurately and completely all of the information required to be maintained under 29 CFR 5.5(a)(3)(i), except that full social security numbers and home addresses shall not be included on weekly transmittals. Instead the payrolls shall only need to include an individually identifying number for each employee (e.g., the last four digits of the employee's social security number). The required weekly payroll information may be submitted in any form desired. Optional Form WH-347 is available for this purpose from the Wage and Hour Division Web site at http://www.dol.gov/esa/whd/forms/wh347instr.htm or its successor site. The prime contractor is responsible for the submission of copies of payrolls by all subcontractors. Contractors and subcontractors shall maintain the full social security number and current address of each covered worker, and shall provide them upon request to DOE if the agency is a party to the contract, but if the agency is not such a party, the contractor will submit them to the applicant, sponsor, or owner, as the case may be, for transmission to DOE, the contractor, or the Wage and Hour Division of the Department of Labor for purposes of an investigation or audit of compliance with prevailing wage requirements. It is not a violation of this section for a prime contractor to require a subcontractor to provide addresses and social security numbers to the prime contractor for its own records, without weekly submission to the sponsoring government agency (or the applicant, sponsor, or owner).

(ii)(B) Each payroll submitted shall be accompanied by a "Statement of Compliance," signed by the contractor or subcontractor or his or her agent who pays or supervises the payment of the persons employed under the contract and shall certify the following:

(1) That the payroll for the payroll period contains the information required to be provided under Sec. 5.5 (a)(3)(ii) of Regulations, 29 CFR part 5, the appropriate information is being maintained under Sec. 5.5 (a)(3)(i) of Regulations, 29 CFR part 5, and that such information is correct and complete;
(2) That each laborer or mechanic (including each helper, apprentice, and trainee) employed on the contract during the payroll period has been paid the full weekly wages earned, without rebate, either directly or indirectly, and that no deductions have been made either directly or indirectly from the full wages earned, other than permissible deductions as set forth in Regulations, 29 CFR part 3;
(3) That each laborer or mechanic has been paid not less than the applicable wage rates and fringe benefits or cash equivalents for the classification of work performed, as specified in the applicable wage determination incorporated into the contract.

(ii)(C) The weekly submission of a properly executed certification set forth on the reverse side of Optional Form WH-347 shall satisfy the requirement for submission of the "Statement of Compliance" required by paragraph (a)(3)(ii)(B) of this section.

(ii)(D) The falsification of any of the above certifications may subject the contractor or subcontractor to civil or criminal prosecution under section 1001 of title 18 and section 231 of title 31 of the United States Code.

(iii) The contractor or subcontractor shall make the records required under paragraph (a)(3)(i) of this section available for inspection, copying, or transcription by authorized representatives of DOE or the Department of Labor, and shall permit such representatives to interview employees during working hours on the job. If the contractor or subcontractor fails to submit the required records or to make them available, the Federal agency may, after written notice to the contractor, sponsor, applicant, or owner, take such action as may be necessary to cause the suspension of any further payment, advance, or guarantee of funds. Furthermore, failure to submit the required records upon request or to make such records available may be grounds for debarment action pursuant to 29 CFR 5.12.

**(4) Apprentices and trainees**

(i) Apprentices. Apprentices will be permitted to work at less than the predetermined rate for the work they performed when they are employed pursuant to and individually registered in a bona fide apprenticeship program registered with the U.S. Department of Labor, Employment and Training Administration, Office of Apprenticeship Training, Employer and Labor Services, or with a State Apprenticeship Agency recognized by the Office, or if a person is employed in his or her first 90 days of probationary employment as an apprentice in such an apprenticeship program, who is not individually registered in the program, but who has been certified by the Office of Apprenticeship Training, Employer and Labor Services or a State Apprenticeship Agency (where appropriate) to be eligible for probationary employment as an apprentice. The allowable ratio of apprentices to journeymen on the job site in any craft classification shall not be greater than the ratio permitted to the contractor as to the entire work force under the registered program. Any worker listed on a payroll at an apprentice wage rate, who is not registered or otherwise employed as stated above, shall be paid not less than the applicable wage rate on the wage determination for the classification of work actually performed. In addition, any apprentice performing work on the job site in excess of the ratio permitted under the registered program shall be paid not less than the applicable wage rate on the wage determination for the work actually performed. Where a contractor is performing construction on a project in a locality other than that in which its program is registered, the ratios and wage rates (expressed in percentages of the journeyman's hourly rate) specified in the contractor's or subcontractor's registered program shall be observed. Every apprentice must be paid at not less than the rate specified in the registered program for the apprentice's level of progress, expressed as a percentage of the journeymen hourly rate specified in the applicable wage determination. Apprentices shall be paid fringe benefits in accordance with the provisions of the apprenticeship program. If the apprenticeship program does not specify fringe benefits, apprentices must be paid the full amount of fringe benefits listed on the wage determination for the applicable classification. If the Administrator determines that a different practice prevails for the applicable apprentice classification, fringes shall be paid in accordance with that determination. In the event the Office of Apprenticeship Training, Employer and Labor Services, or a State Apprenticeship Agency recognized by the Office, withdraws approval of an apprenticeship program, the contractor will no longer be permitted to utilize apprentices at less than the applicable predetermined rate for the work performed until an acceptable program is approved.

(ii) Trainees. Except as provided in 29 CFR 5.16, trainees will not be permitted to work at less than the predetermined rate for the work performed unless they are employed pursuant to and individually registered in a program which has received prior approval, evidenced by formal certification by the U.S. Department of Labor, Employment and Training Administration. The ratio of trainees to journeymen on the job site shall not be greater than permitted under the plan approved by the Employment and Training Administration. Every trainee must be paid at not less than the rate specified in the approved program for the trainee's level of progress, expressed as a percentage of the journeyman hourly rate specified in the applicable wage determination. Trainees shall be paid fringe benefits in accordance with the provisions of the trainee program. If the trainee program does not mention fringe benefits, trainees shall be paid the full amount of fringe benefits listed on the wage determination unless the Administrator of the Wage and Hour Division determines that there is an apprenticeship program associated with the corresponding journeyman wage rate on the wage determination which provides for less than full fringe benefits for apprentices. Any employee listed on the payroll at a trainee rate who is not registered and participating in a training plan approved by the Employment and Training Administration shall be paid not less than the applicable wage rate on the wage determination for the classification of work actually performed. In addition, any trainee performing work on the job site in excess of the ratio permitted under the registered program shall be paid not less than the applicable wage rate on the wage determination for the work actually performed. In the event the Employment and Training Administration withdraws approval of a training program, the contractor will no longer be permitted to utilize trainees at less than the applicable predetermined rate for the work performed until an acceptable program is approved.

(iii) Equal employment opportunity. The utilization of apprentices, trainees and journeymen under this part shall be in conformity with the equal employment opportunity requirements of Executive Order 11246, as amended, and 29 CFR part 30.

**(5) Compliance with Copeland Act requirements.**

The contractor shall comply with the requirements of 29 CFR part 3, which are incorporated by reference in this contract.

**(6) Subcontracts.**

The contractor or subcontractor shall insert in any subcontracts the clauses contained in 29 CFR 5.5(a)(1) through (10) and such other clauses as DOE may by appropriate instructions require, and also a clause requiring the subcontractors to include these clauses in any lower tier subcontracts. The prime contractor shall be responsible for the compliance by any subcontractor or lower tier subcontractor with all the contract clauses in 29 CFR 5.5.

**(7) Contract termination: debarment.**

A breach of the contract clauses in 29 CFR 5.5 may be grounds for termination of the contract, and for debarment as a contractor and a subcontractor as provided in 29 CFR 5.12.

**(8) Compliance with Davis-Bacon and Related Acts requirements.**

All rulings and interpretations of the Davis-Bacon and Related Acts contained in 29 CFR parts 1, 3, and 5 are herein incorporated by reference in this contract.

**(9) Disputes concerning labor standards.**

Disputes arising out of the labor standards provisions of this contract shall not be subject to the general disputes clause of this contract. Such disputes shall be resolved in accordance with the procedures of the Department of Labor set forth in 29 CFR parts 5, 6, and 7. Disputes within the meaning of this clause include disputes between the contractor (or any of its subcontractors) and the contracting agency, the U.S. Department of Labor, or the employees or their representatives.

**(1) Certification of eligibility.**

(i) By entering into this contract, the contractor certifies that neither it (nor he or she) nor any person or firm who has an interest in the contractor's firm is a person or firm ineligible to be awarded Government contracts by virtue of section 3(a) of the Davis-Bacon Act or 29 CFR 5.12(a)(1).

(ii) No part of this contract shall be subcontracted to any person or firm ineligible for award of a Government contract by virtue of section 3(a) of the Davis-Bacon Act or 29 CFR 5.12(a)(1).

(iii) The penalty for making false statements is prescribed in the U.S. Criminal Code, 18 U.S.C. 1001.

**CONFIDENTIAL& PROPRIETARY**
**CONFIDENTIAL TRADE SECRET INFORMATION**

# EXHIBIT J-2

## DAVIS-BACON ACT WAGE DETERMINATION(S)

1. For all construction (as defined in DOL regulations at 29 CFR 5.2 to include installation where appropriate, hereinafter "construction") under this Agreement and subcontracts hereunder, incorporate the following "Heavy" wage determination schedule and conformances: GA90 Modification 0 (1/03/14), found at: http://www.wdol.gov/wdol/scafiles/davisbacon/GA90.dvb, and attached hereto as Exhibit J-3 .

2. For all construction under this Agreement and subcontracts hereunder, on sheltered enclosures with walk-in access for the purpose of housing persons, machinery, equipment, incorporate the following "Building" wage determination schedule: GA126 Modification 1 (1/17/14) found at http://www.wdol.gov/wdol/scafiles/davisbacon/GA126.dvb, and attached hereto as Exhibit J-4 .

3. For all construction under this Agreement and subcontracts hereunder, on paved roads and other paved surfaces, please use GA7 Modification 0 (1/3/14) "Highway" schedule found at http://www.wdol.gov/wdol/scafiles/davisbacon/GA7.dvb, and attached hereto as Exhibit J-5 .

**EXHIBIT J-3**

**HEAVY WAGE DETERMINATION**

General Decision Number: GA140090 01/03/2014 GA90

Superseded General Decision Number: GA20130090

State: Georgia

Construction Type: Heavy
Heavy Construction, Includes Water and Sewer Lines, and Heavy Construction on Treatment Plant Sites and Industrial Sites (Refineries, Power Plants, Chemical and Manufacturing Plants, Paper Mills, Etc.)

Counties: Burke, McDuffie and Richmond Counties in Georgia.

| Modification Number | Publication Date |
|---|---|
| 0 | 01/03/2014 |

* ELEC1579-002 10/01/2013

| | Rates | Fringes |
|---|---|---|
| ELECTRICIAN | $23.00 | 11.40 |

ENGI0474-029 07/01/2013

BURKE & RICHMOND COUNTIES

| | Rates | Fringes |
|---|---|---|
| POWER EQUIPMENT OPERATOR: | | |
| Crane: 119 Tons and Under | $24.55 | 12.30 |
| Crane: 120 to 249 Tons | $25.55 | 12.30 |
| Crane: 250 to 499 Tons | $26.55 | 12.30 |
| Crane: 500 Tons and Larger | $27.55 | 12.30 |
| Mechanic | $24.55 | 12.30 |

ENGI0926-032 07/01/2013

MCDUFFIE COUNTY

**CONFIDENTIAL& PROPRIETARY**
**CONFIDENTIAL TRADE SECRET INFORMATION**

| | | Rates | Fringes |
|---|---|---|---|
| POWER EQUIPMENT OPERATOR: Crane, Mechanic | $ | 27.88 | 10.13 |

SUGA2012-108 08/11/2012

| | | Rates | Fringes |
|---|---|---|---|
| CARPENTER (Form Work Only) | $ | 15.44 | 0.00 |
| CARPENTER, Excludes Form Work | $ | 14.76 | 0.00 |
| CEMENT MASON/CONCRETE FINISHER | $ | 16.96 | 0.00 |
| IRONWORKER, REINFORCING | $ | 13.30 | 1.66 |
| LABORER: Common or General | $ | 9.84 | 0.00 |
| LABORER: Pipelayer | $ | 9.48 | 0.00 |
| OPERATOR: Backhoe/Excavator/Trackhoe | $ | 12.80 | 0.00 |
| OPERATOR: Bulldozer | $ | 14.58 | 0.00 |
| OPERATOR: Grader/Blade | $ | 20.24 | 0.00 |
| OPERATOR: Loader | $ | 16.59 | 4.13 |
| OPERATOR: Piledriver | $ | 18.72 | 2.06 |
| OPERATOR: Roller | $ | 12.04 | 0.69 |
| TRUCK DRIVER: Dump Truck | $ | 12.79 | 0.00 |
| TRUCK DRIVER: Lowboy Truck | $ | 17.28 | 1.84 |

WELDERS - Receive rate prescribed for craft performing operation to which welding is incidental.

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Unlisted classifications needed for work not included within the scope of the classifications listed may be added after award only as provided in the labor standards contract clauses (29CFR 5.5 (a) (1) (ii)).

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The body of each wage determination lists the classification and wage rates that have been found to be prevailing for the cited type(s) of construction in the area covered by the wage determination. The classifications are listed in alphabetical order of “identifiers” that indicate whether the particular rate is union or non-union.

Union Identifiers

An identifier enclosed in dotted lines beginning with characters other than “SU” denotes that the union classification and rate have found to be prevailing for that classification. Example: PLUM0198-005 07/01/2011. The first four letters , PLUM, indicate the international union and the four-digit number, 0198, that follows indicates the local union number or district council number where applicable , i.e., Plumbers Local 0198. The next number, 005 in the example, is an internal number used in processing the wage determination. The date, 07/01/2011, following these characters is the effective date of the most current negotiated rate/collective bargaining agreement which would be July 1, 2011 in the above example.

Union prevailing wage rates will be updated to reflect any changes in the collective bargaining agreements governing the rates.

0000/9999: weighted union wage rates will be published annually each January.

Non-Union Identifiers

Classifications listed under an “SU” identifier were derived from survey data by computing average rates and are not union rates; however, the data used in computing these rates may include both union and non-union data. Example: SULA2004-007 5/13/2010. SU indicates the rates are not union majority rates, LA indicates the State of Louisiana; 2004 is the year of the survey; and 007 is an internal number used in producing the wage determination. A 1993 or later date, 5/13/2010, indicates the classifications and rates under that identifier were issued as a General Wage Determination on that date.

Survey wage rates will remain in effect and will not change until a new survey is conducted.

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WAGE DETERMINATION APPEALS PROCESS

1.) Has there been an initial decision in the matter? This can be:

an existing published wage determination

a survey underlying a wage determination

a Wage and Hour Division letter setting forth a position on a wage determination matter a conformance (additional classification and rate) ruling

On survey related matters, initial contact, including requests for summaries of surveys, should be with the Wage and Hour Regional Office for the area in which the survey was conducted because those Regional Offices have responsibility for the Davis-Bacon survey program. If the response from this initial contact is not satisfactory, then the process described in 2.) and 3.) should be followed.

With regard to any other matter not yet ripe for the formal process described here, initial contact should be with the Branch of Construction Wage Determinations. Write to:

Branch of Construction Wage Determinations
Wage and Hour Division
U.S. Department of Labor
200 Constitution Avenue, N.W.
Washington, DC 20210

2.) If the answer to the question in 1.) is yes, then an interested party (those affected by the action) can request review and reconsideration from the Wage and Hour Administrator (See 29 CFR Part 1.8 and 29 CFR Part 7). Write to:

Wage and Hour Administrator
U.S. Department of Labor
200 Constitution Avenue, N.W.
Washington, DC 20210

The request should be accompanied by a full statement of the interested party's position and by any information (wage payment data, project description, area practice material, etc.) that the requestor considers relevant to the issue.

3.) If the decision of the Administrator is not favorable, an interested party may appeal directly to the Administrative Review Board (formerly the Wage Appeals Board). Write to:

Administrative Review Board
U.S. Department of Labor
200 Constitution Avenue, N.W.
Washington, DC 20210

*4.)* All decisions by the Administrative Review Board are final.

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*END OF GENERAL DECISION*

Exhibit J-3

U.S. Department of Labor

Wage and Hour Division
Washington, D.C. 20210

JUN 2 2014

Ms. Nikky Ude
Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585
Nikky.Ude@hq.doe.gov

RE: Project No.: Units 3 and 4 of Vogtle Electric Plant
Wage Decision No.: GA140090 Mod. 0
Location: Burke County, GA
WHD Number: 4790

Dear Ms. Ude:
This is in response to your request proposing the additional classifications and wage rates to the above wage decision in accordance with 29 CFR 5.5(a)(1)(ii).

| PROPOSED CLASSIFCATIONS | PROPOSED HOURLY RATE | FRINGE BENEFITS |
|---|---|---|
| Asbestos Worker/Insulator | $23.92 | $12.04 |
| Millwright | $26.95 | $11.55 |
| Sprinkler Fitter | $25.99 | $15.87 |
| Mechanic Services | $18.21 | $12.35 |
| Machinist | $26.95 | $11.55 |
| Well Driller | $24.55 | $12.35 |

The request for Mechanic Services is not approved because the work to be performed by this classification may be performed by a classification already included in the wage decision [see 29 C.F.R., section 5.5(a)(1)(ii)(A)(1)]. The appropriate classification is Mechanic at a rate of $24.55 per hour plus $12.30 in fringe benefits and shall be paid to all workers performing work in the classification under this contract from the first day on which work is performed.

The Machinist is not subject as the Davis-Bacon Act provides that prevailing wages are to be paid to all mechanics and laborers employed directly upon the site of work. The regulations [see 29 C.F.R., section 5.2(1)] define the site of work as limited to the physical place or places where the construction called for in the contract will remain when work on it is completed and other adjacent or nearby property used in the construction.

The remaining classifications and wage rates are approved and the wage rates proposed must be paid to all workers performing work within the classifications under this contract from the first day work is performed.

**CONFIDENTIAL& PROPRIETARY**
**CONFIDENTIAL TRADE SECRET INFORMATION**

Your request has been conformed consistent with All Agency Memorandum 213 ( http://www.wdol.gov/aam/aam213.pdf) which describes the conformance process in detail and the basis on which your proposed rate was denied. Any requests for appeal of the conformance decision must be made within thirty (30) days from the date of this letter. If you have any questions or concerns regarding this conformance decision, please contact the undersigned at the telephone or email address listed below.

Sincerely,

/s/ T. Holmes for

Kenneth Reinshuttle
Section Chief
Davis Bacon Branch
Wage & Hour Division
202.693.1016
reinshuttle.ken@dol.gov

**EXHIBIT J-4**

**BUILDING WAGE DETERMINATION**

General Decision Number: GA140126 01/17/2014 GA126

Superseded General Decision Number: GA20130126

State: Georgia

Construction Type: Building

County: Burke County in Georgia.

| Modification Number | Publication Date |
|---|---|
| 0 | 01/03/2014 |
| 1 | 01/17/2014 |

BOIL0026-001 01/01/2013

| | Rates | Fringes |
|---|---|---|
| BOILERMAKER | $24.91 | $19.69 |

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* ELEV0032-001 01/01/2014

| | Rates | Fringes |
|---|---|---|
| ELEVATOR MECHANIC | $36.96 | 26.785+a+b |

PAID HOLIDAYS:

* a. New Year's Day, Memorial Day, Independence Day, Labor Day, Vetern's Day, Thanksgiving Day, the Friday after Thanksgiving, and Christmas Day.

* b. Employer contributes 8% of regular hourly rate to vacation pay credit for employee who has worked in business more than 5 years; 6% for less than 5 years' service.

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Exhibit J-4 Page 1

| | | Rates | Fringes |
|---|---|---|---|
| POWER EQUIPMENT OPERATOR: Backhoe/Excavator, Bobcat/Skid Steer/Skid Loader, Bulldozer, Forklift (under 15 tons), and Loader Crane (over 10 tons) and Forklift | $ | 22.72 | 12.30 |
| (15 tons and over) | $ | 24.55 | 12.30 |
| Crane (over 120 tons) | $ | 25.55 | 12.30 |
| Crane (over 250 tons) | $ | 26.55 | 12.30 |
| Oiler | $ | 20.38 | 12.30 |

PLUM0150-006 10/01/2012

| | Rates | Fringes |
|---|---|---|
| PLUMBER/PIPEFITTER | 22.94 | 12.71 |

SHEE0085-003 08/01/2012

| | | Rates | Fringes |
|---|---|---|---|
| SHEET METAL WORKER (Including HVAC Duct Installation; Excluding Metal Roof Installation) | $ | 28.34 | 11.55 |

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SUGA2012-033 08/11/2012

| | | Rates | Fringes |
|---|---|---|---|
| BRICKLAYER | $ | 16.00 | 0.00 |
| CARPENTER, Includes Drywall Hanging and Metal Stud Installation | $ | 15.28 | 0.00 |
| CEMENT MASON/CONCRETE FINISHER | $ | 16.58 | 0.00 |
| DRYWALL FINISHER/TAPER | $ | 17.00 | 0.00 |
| ELECTRICIAN | $ | 19.71 | 3.60 |
| HVAC MECHANIC (Installation of HVAC Unit Only, Excludes Installation of HVAC Pipe and Duct) | $ | 18.00 | 3.89 |
| IRONWORKER, REINFORCING | $ | 17.94 | 0.00 |
| IRONWORKER, STRUCTURAL | $ | 20.00 | 0.35 |
| LABORER: Common or General | $ | 10.25 | 0.32 |

| | | | |
|---|---|---|---|
| LABORER: Mason Tender – Brick | $ | 9.00 | 0.00 |
| LABORER: Pipelayer | $ | 12.00 | 0.23 |

| | | Rates | Fringes |
|---|---|---|---|
| OPERATOR: Grader/Blade | $ | 17.52 | 0.00 |
| PAINTER: Brush, Roller and Spray | $ | 16.00 | 1.62 |
| ROOFER (Installation of Metal Roofs Only) | $ | 15.02 | 0.00 |
| ROOFER, Excludes Installation of Metal Roofs | $ | 10.76 | 0.00 |
| TILE FINISHER | $ | 10.31 | 0.00 |
| TILE SETTER | $ | 19.50 | 0.00 |
| TRUCK DRIVER: Dump Truck | $ | 12.70 | 0.00 |
| TRUCK DRIVER: Lowboy Truck | $ | 17.41 | 0.00 |

WELDERS - Receive rate prescribed for craft performing operation to which welding is incidental.

Unlisted classifications needed for work not included within the scope of the classifications listed may be added after award only as provided in the labor standards contract clauses (29CFR 5.5 (a) (1) (ii)).

The body of each wage determination lists the classification and wage rates that have been found to be prevailing for the cited type(s) of construction in the area covered by the wage determination. The classifications are listed in alphabetical order of "identifiers" that indicate whether the particular rate is union or non-union.

Union Identifiers

An identifier enclosed in dotted lines beginning with characters other than "SU" denotes that the union classification and rate have found to be prevailing for that classification. Example: PLUM0198-005 07/01/2011. The first four letters , PLUM, indicate the international union and the four-digit number, 0198, that follows indicates the local union number or district council number where applicable , i.e., Plumbers Local 0198. The next number, 005 in the example, is an internal number used in processing the wage determination. The date, 07/01/2011, following these characters is the effective date of the most current negotiated rate/collective bargaining agreement which would be July 1, 2011 in the above example.

Union prevailing wage rates will be updated to reflect any changes in the collective bargaining agreements governing the rates.

0000/9999: weighted union wage rates will be published annually each January.

Non-Union Identifiers

Classifications listed under an “SU” identifier were derived from survey data by computing average rates and are not union rates; however, the data used in computing these rates may include both union and non-union data. Example: SULA2004-007 5/13/2010. SU indicates the rates are not union majority rates, LA indicates the State of Louisiana; 2004 is the year of the survey; and 007 is an internal number used in producing the wage determination. A 1993 or later date, 5/13/2010, indicates the classifications and rates under that identifier were issued as a General Wage Determination on that date.

Survey wage rates will remain in effect and will not change until a new survey is conducted.

WAGE DETERMINATION APPEALS PROCESS

1.) Has there been an initial decision in the matter? This can be:

an existing published wage determination

a survey underlying a wage determination

a Wage and Hour Division letter setting forth a position on a wage determination matter

a conformance (additional classification and rate) ruling

On survey related matters, initial contact, including requests for summaries of surveys, should be with the Wage and Hour Regional Office for the area in which the survey was conducted because those Regional Offices have responsibility for the Davis-Bacon survey program. If the response from this initial contact is not satisfactory, then the process described in 2.) and 3.) should be followed.

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Branch of Construction Wage Determinations
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U.S. Department of Labor
200 Constitution Avenue, N.W.

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2.) If the answer to the question in 1.) is yes, then an interested party (those affected by the action) can request review and reconsideration from the Wage and Hour Administrator (See 29 CFR Part 1.8 and 29 CFR Part 7). Write to:

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3.) If the decision of the Administrator is not favorable, an interested party may appeal directly to the Administrative Review Board (formerly the Wage Appeals Board). Write to:

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Washington, DC 20210

4.) All decisions by the Administrative Review Board are final.

END OF GENERAL DECISION

**EXHIBIT J-5**

**HIGHWAY WAGE DETERMINATION**

General Decision Number: GA140007 01/03/2014 GA7

Superseded General Decision Number: GA20130007

State: Georgia

Construction Type: Highway

Counties: Burke, Columbia, Glascock, Hancock, Jefferson, Jenkins, Lincoln, McDuffie, Richmond, Taliaferro, Warren, Washington and Wilkes Counties in Georgia.

HIGHWAY CONSTRUCTION PROJECTS

| Modification Number | Publication Date |
|---|---|
| 0 | 01/03/2014 |

SUGA2011-007 03/07/2011

| | | Rates | Fringes |
|---|---|---|---|
| CARPENTER | $ | 11.45 | |
| CEMENT MASON/CONCRETE FINISHER | $ | 11.36 | |
| LABORER | | | |
| Asphalt Raker | $ | 11.00 | |
| Asphalt Screed Person | $ | 10.50 | |
| Common or General | $ | 8.93 | |
| Form Setter | $ | 10.35 | |
| Guardrail Erector | $ | 13.50 | |
| Milling Machine Ground Person | $ | 10.00 | |
| Pipe Layer | $ | 10.20 | |
| POWER EQUIPMENT OPERATOR: | | | |
| Asphalt Distributor | $ | 14.10 | |

| | | |
|---|---|---|
| Asphalt Paver/Spreader | $ | 12.00 |
| Backhoe/Excavator | $ | 10.80 |
| Bulldozer | $ | 11.60 |
| Compactor | $ | 10.00 |
| Crane/Dragline | $ | 17.50 |
| Front End Loader | $ | 10.70 |
| Material Transfer Vehicle (Shuttle Buggy) | $ | 11.30 |

**CONFIDENTIAL& PROPRIETARY**
**CONFIDENTIAL TRADE SECRET INFORMATION**

| | | Rates | Fringes |
|---|---|---|---|
| Mechanic | $ | 12.75 | |
| Milling Machine | $ | 11.50 | |
| Motorgrader Fine Grade | $ | 14.55 | |
| Motorgrader/Blade | $ | 16.00 | |
| Roller | $ | 10.00 | |
| Water Truck | $ | 11.25 | |
| TRUCK DRIVER | | | |
| 26,000 GVW & Under | $ | 10.79 | |
| 26,001 GVW & Over | $ | 12.75 | |

WELDERS - Receive rate prescribed for craft performing operation to which welding is incidental.

Unlisted classifications needed for work not included within the scope of the classifications listed may be added after award only as provided in the labor standards contract clauses (29CFR 5.5 (a) (1) (ii)).

The body of each wage determination lists the classification and wage rates that have been found to be prevailing for the cited type(s) of construction in the area covered by the wage determination. The classifications are listed in alphabetical order of “identifiers” that indicate whether the particular rate is union or non-union.

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Union prevailing wage rates will be updated to reflect any changes in the collective bargaining agreements governing the rates.

0000/9999: weighted union wage rates will be published annually each January.

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WAGE DETERMINATION APPEALS PROCESS

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a Wage and Hour Division letter setting forth a position on a wage determination matter

a conformance (additional classification and rate) ruling

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**CONFIDENTIAL TRADE SECRET INFORMATION**

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U.S. Department of Labor
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The request should be accompanied by a full statement of the interested party's position and by any information (wage payment data, project description, area practice material, etc.) that the requestor considers relevant to the issue.

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U.S. Department of Labor
200 Constitution Avenue, N.W.
Washington, DC 20210

4.) All decisions by the Administrative Review Board are final.

END OF GENERAL DECISION

**Exhibit K – Flow Down Clauses**

| Section and Title | Limitations |
|---|---|
| 2.3.3 Project Information Management Systems | None. |
| 2.5.2 Access for Southern Nuclear Co-Located Personnel | None. |
| 2.6 Performance Standards | None. |
| 2.11 Clean-up and Waste Disposal | Flow-down is limited to on-Site Subcontractors. |
| 2.13 Hazardous Materials | Flow-down is limited to on-Site Subcontractors. |
| 2.15 Safety Program | The flow-down is compliance with Contractor's Project Safety Manual (i.e., not provision of a manual) and compliance with the provisions of 2.15 that apply to Subcontractors and on-Site Personnel. |
| 2.17.5 through 2.17.10 Subcontracting | None. |
| 2.19 Documentation Necessary for ITAACs | Flow-down is limited to Subcontractors and Vendors whose work involves ITAACs. |
| 2.20 Support for Government Approvals and Requests | None. |
| 4.2 Owners' Right to Inspect, Stop and Re- perform Work | None. |
| 5.1 Quality Assurance | None. |
| 5.3 Access for Inspection and Audit | None. |
| Article 17 Insurance | To the extent an OCIP is not in place, Subcontractors will be required to meet the insurance requirements imposed on Contractor under Article 16 as appropriate to the Subcontractor's scope of work. |
| Article 22 Protected Information and Export Control | Flow-down for Protected Information is limited to Vendors or Subcontractors to which Confidential and Proprietary Information is disclosed. |

**Exhibit K – Flow Down Clauses**

| Section and Title | Limitations |
|---|---|
| 24.1 Transfer of Title | Flow-down is limited to ensuring that passage of title conforms to Contractor's obligation under this section. |
| 24.1.2 – 24.1.3 Intellectual Property | None |
| Article 25 Applicable Laws and Regulations | None. |
| Article 26 Equal Employment Opportunity | None. |
| Article 28 Site and Security Rules and Policies | Flow-down is limited to Subcontractors performing Work on-Site. |
| Article 29 Unescorted Access | Flow-down is limited to Subcontractors whose personnel will apply for or have been granted unescorted access to VEGP Units 1 and 2 or Unit 3 or Unit 4. |
| Article 30 Fitness for Duty | None. |
| Article 31 Free Flow of Information | None. |
| Article 32 No Toleration of Unacceptable Behaviors | None. |
| Article 33 Non-English Speaking Workers | Flow-down is limited to Subcontractors performing Work on-Site. |
| Article 35 Qualifications and Protection of Assigned Personnel | None. |
| 36.1 Technical Documentation | None. |
| 36.2 Accounting Records | None. |
| 36.3 Maintenance of Records Generally | Flow-down is limited to Subcontractors and Vendors subject to 10 C.F.R. § 50.71 and other applicable Laws. |
| 36.4 Right to Audit | None. |
| 36.6 Sales Tax Records | None. |
| 37.3 Cooperation and Audit | None. |

# Exhibit L – Trend Program

Contractor will implement a robust Trend Program for the Vogtle Units 3 & 4 Construction Completion project. The Contractor Trend Program will provide input to and inform the Owner change control program for the overall Project.

Program Structure

The Contractor Trend Program will be structured such that the process and outputs will inform Contractor Project Management as to the running status of change and its cumulative effect on available contingencies. The actual process of change identification, quantification, and acceptance (or resolution) will be set out in a project procedure, providing standard terminology, responsibilities, accountabilities, cycle times, and deliverables, such that the Bechtel project team has the rules of the road for managing change as it happens.

The Contractor Trend Program has 3 main objectives:

- Provide a platform for engaging project leadership in the management of the contract cost and schedule baselines and their defined contingencies.
- Provide a transparent process for the identification, quantification, and resolution of cost and/or schedule changes within the Contractor scope of Work as they occur. Such cost and schedule changes may include trends potentially impacting Target Construction Cost and/or Target Completion Date(s).
- Provide information on the nature of change and the rate at which change is occurring and its influence on established contingencies, as well as inform the overarching Owner change control program.

Scope and Engagement

The Contractor Trend Program will envelope the scope of work under contract and will be owned by the Contractor Project Manager. As the senior leader, setting change management as a priority drives behavior and participation. While Contractor Project Controls may ‘keep the books’, the Contractor Project Manager sets the tone, and holds the project team accountable for promoting a cost and schedule conscious attitude. With the leadership protocol set, identification of change is open to everyone on the project. In the end, driving for wide understanding of ‘what’s in the budget’ and empowering everyone to raise a hand when they encounter something different, is the lifeblood of the program.

Administering the Program

The Contractor Trend Program will be administered on three fronts: (1) daily handling of individual trends in a consistent manner, (2) weekly meetings to review and adjudicate trends, and (3) monthly reporting of overall status of the program (metric-based information) including contingency balance.

# Exhibit L – Trend Program

The basic process will be as follows:

1. Trends are identified, entered into the Trend Log, and initially classified as "Potential."
2. Information is gathered, studies performed, etc. as required to substantiate and capture the extent of condition and an estimated value (order of magnitude hours and dollars) for each Trend. A determination is also made as to whether the Trend relates to in-scope or out-of-scope work.
3. Each Trend is presented in the Bechtel Trend Meeting, and if accepted, is classified as "Resolved." If not accepted and follow up actions are requested, the Trend is classified as "Unresolved" and will be revisited in a later Bechtel Trend Meeting.
4. Each month, in-scope trends that have been "Resolved" are summarized and an offset to available contingency is recorded (either positive or negative). Out-of-Scope Trends or Trends that adjust the project Target Assumptions that have been "Resolved" are forwarded to contract administration.
5. A Monthly Trend Report is prepared, including the full Trend Log, and a summary report showing the activity for the month and status of available contingency.

Integration of the Contractor Trend Program with Owner Change Control

The Contractor Trend Program will work within the broader Owner change control program for the Project. The overarching Owner change control program will encompass all the engineering, procurement, construction, and other aspects of the project. The Contractor Trend Program will include identified interaction points and information exchange needed to support the Owner change control program.

A Monthly Trend Report will be prepared that will include the status of individual trends, metrics on Trends at the major status points (Potential, Unresolved, and Resolved), as well as a presentation of how Resolved Trends have influenced the available contingency balance both for the month and since the baseline was established. The Monthly Trend Report will also include information on Out-of-Scope Trends or Trends that adjust the Target Assumptions, which would be initial inputs to the Owner change control program.

The Monthly Trend Report will be included in Contractor's overall monthly report to Owners for the Project.

**Exhibit M – Target Construction Cost and List of Excluded Costs**

| Target Construction Cost Summary | | |
|---|---|---|
| **Cost Category** | **Hours (in 1,000s)** | **Estimated Cost (in millions)** |
| Direct Craft Labor | [***] | [***] |
| Field Indirects | [***] | [***] |
| Field Non-Manual Services | [***] | [***] |
| Home Office Services | [***] | [***] |
| | **Subtotal** | [***] |
| Escalation | | [***] |
| Craft Processing Related Costs (DIC insurance and others) | | [***] |
| Construction Contingency | | [***] |
| Welder Incentives | | [***] |
| **Target Construction Cost** | | [***] |

Excluded Costs

The following costs are "Excluded Costs" and will not be included in the calculation of Combined Construction Costs:

(a) any per diems or other incentives paid to craft labor engaged in performance of the Work (except for such payments to welders);
(b) any Taxes paid in connection with the Work or Taxes included in payments to Contractor-Managed Subcontractors;
(c) costs paid in connection with any non-resident sales tax bond required to be provided by Contractor;
(d) amounts paid to Bechtel Power Corporation under the Amended and Restated Staff Augmentation Agreement;
(e) amounts incurred by Southern Nuclear or any of the Owners with respect to secondees provided to Bechtel Power Corporation under the Amended and Restated Staff Augmentation Agreement;
(f) amounts paid by Owners to Contractor-Managed Subcontractors with respect to work performed by them prior to the Effective Date;
(g) amounts paid by Owners to Contractor-Managed Subcontractors to the extent that such amounts paid exceed the amounts recommended for payment by Contractor pursuant to Section 3.3.3, but only to the extent that such amounts are never required to be paid to such subcontractors;
(h) amounts paid by Owners to Contractor-Managed Subcontractors with respect to work performed by them for work scope that is not related to the achievement of Final Completion;

(i) amounts paid by Owners to Contractor with respect to support provided to the Owners in connection with DOE loan guarantees and/or dealing with Government Authorities in accordance with Section 2.20 of the Agreement;

(j) amounts paid by Owners to Contractor or Contractor-Managed Subcontractors in order to complete or reperform work performed prior to the Effective Date, including work identified in the Legacy Work Packages and the Completed Work Packages listed in Exhibit V, and that portion of work performed prior to the Effective Date and included in the Work in Progress Work Packages listed in Exhibit V.

Exhibit M-1 - Field Non-Manual Resource Curve

[***]

Exhibit N – Commercial Rates

**Bechtel Power Corporation – Non-Manual Related Rates**

| Contract Article | Cost Category | Field Office Rates | | Home Office Rates | |
|---|---|---|---|---|---|
| | | **Straight Time** | **Overtime** | **Straight Time** | **Overtime** |
| | | | | | |
| **7.1.1 (i)** | **Payroll Adds [1]** | [***] | [***] | [***] | [***] |
| **7.1.1 (iii)** | **Non-manual Indirect Costs** | [***] | [***] | [***] | [***] |
| | | [***] | [***] | [***] | [***] |
| **7.1.1 (vii)** | **Direct Costs Related to IT** | [***] | [***] | [***] | [***] |
| | *Nuclear Power IT Software* | [***] | [***] | [***] | [***] |
| | *Global IT Infrastructure* | [***] | [***] | [***] | [***] |
| | *Global IT Security* | [***] | [***] | [***] | [***] |
| | *Corporate IT Software* | [***] | [***] | [***] | [***] |
| | | [***] | [***] | [***] | [***] |
| **7.1.1 (viii)** | **Other Direct Costs** | [***] | [***] | [***] | [***] |
| | Non-Manual Facilities/Offices | [***] | [***] | [***] | [***] |
| | Communications and related hardware assigned to Personnel | [***] | [***] | [***] | [***] |
| | IT related hardware including computers assigned to Personnel | [***] | [***] | [***] | [***] |

Notes:

1) Payroll Adds are for calendar year 2017 and subject to annual true-up in accordance with Article 7.1.1(i).

| Contract Article | Cost Category | Applied to CAS Employed Craft | | | |
|---|---|---|---|---|---|
| | | **Straight Time** | **Overtime** | | |
| | | | | | |
| **7.1.1 (ix)** | **CAS overhead recovery** | [***] | [***] | | |

Exhibit N – Commercial Rates

**Richmond County Construction LLC – Non-Manual Related Rates**

| Contract Article | Cost Category | Field Office Rates | | Home Office Rates | |
|---|---|---|---|---|---|
| | | **Straight Time** | **Overtime** | **Straight Time** | **Overtime** |
| | | | | | |
| **7.1.1 (i)** | **Payroll Adds** [1] | | | | |
| | Loaned Employees from Bechtel | [***] | [***] | [***] | [***] |
| | Loaned Employees from Williams | [***] | [***] | [***] | [***] |
| | | [***] | [***] | [***] | [***] |
| **7.1.1 (iii)** | **Non-manual Indirect Costs** | [***] | [***] | [***] | [***] |
| | Loaned Employees from Bechtel | [***] | [***] | [***] | [***] |
| | Loaned Employees from Williams | [***] | [***] | [***] | [***] |
| | | [***] | [***] | [***] | [***] |
| **7.1.1 (vii)** | **Direct Costs Related to IT** | [***] | [***] | [***] | [***] |
| | Loaned Employees from Bechtel | [***] | [***] | [***] | [***] |
| | Loaned Employees from Williams | N/A | N/A | N/A | N/A |
| | | [***] | [***] | [***] | [***] |
| **7.1.1 (viii)** | **Other Direct Costs** | [***] | [***] | [***] | [***] |
| | All Employees | [***] | [***] | [***] | [***] |
| | Non-Manual Facilities/Offices | [***] | [***] | [***] | [***] |
| | Communications and related hardware | [***] | [***] | [***] | [***] |
| | IT related hardware including computers assigned to Personnel | [***] | [***] | [***] | [***] |

Notes:

1) Payroll Adds are for calendar year 2017 and subject to annual true-up in accordance with Article 7.1.1(i).

**Exhibit O – Form of Monthly Funding Request**

# Vogtle 3&4 Project Completion Agreement

## Bechtel Power Corp
## Monthly Funding Request - MMM-YY

| | | THIS INVOICE | NEXT THREE MONTHS | | |
|---|---|---|---|---|---|
| | | MFR-AA | MFR-BB | MFR-CC | MFR-DD |
| **Non-Manual Labor Costs** | | | | | |
| 1 | Construction Non-Manual | | | | |
| | - Number of Staff (Full Time Equivalents) | | | | |
| | - Hours/Week | | | | |
| | - Number of Weeks | - | - | - | - |
| | - Average Cost per Hour | | | | |
| | Estimated Costs | $ - | $ - | $ - | $ - |
| 2 | Home Office Services | | | | |
| | - Estimated Hours | | | | |
| | - Average Cost per Hour | | | | |
| | Estimated Costs | $ - | $ - | $ - | $ - |
| **Manual Labor Costs** | | | | | |
| | Field Manual Labor (Direct & Indirect) | | | | |
| | - Number of Craft (Full time equivalent) | | | | |
| | - Hours/Week | | | | |
| | - Number of Weeks | - | - | - | - |
| | - Average Cost per Hour | | | | |
| | Estimated Costs | $ - | $ - | $ - | $ - |
| **Sub-Total** | | $ - | $ - | $ - | $ - |
| **Contingency @ X%** | | $ - | $ - | $ - | $ - |
| **Total Funding Request** | | **$ -** | $ - | $ - | $ - |

NOTES:
1. Includes Labor and Other Direct Costs (Business travel, LAHA, etc.)
2. Funding Period:

| | From | To | Holidays | Days | Weeks | Weeks (Rounded to full weeks) |
|---|---|---|---|---|---|---|
| MFR-AA | | | | | - | |
| MFR-BB | | | | | - | |
| MFR-CC | | | | | - | |
| MFR-DD | | | | | - | |

# Exhibit P – Form of Invoice

Page 1:

**BECHTEL POWER CORPORATION**
**5323 N. 99th Avenue**
**Glendale, AZ 85305**

**To:**

Vogtle 3 & 4 Owners

**Remittance information:**

**Bank Name:**
**Bank Address:**
**Account Name:**
**Account No.:**
**Bank Code:**

**Payment Reference:** Credit: Bechtel Power Corp
Invoice No.: 26139-1710XXX

| Invoice Number | Date | Job Number | Terms | Due Date | Currency | Account |
|---|---|---|---|---|---|---|
| 26139-1710XXX | 10-Oct-17 | 26139 | Net 15 | 25-Oct-17 | USD | 261-8000 |

To invoice in accordance with the Vogtle 3 & 4 Project Completion Agreement between Vogtle 3 & 4 Owners and Bechtel Power Corporation effective MON-DD-YY

**Master Contract Number: XXXXXXX**
**Contract Number: XXXXXXX**
**PO Number: XXXXXXXX**

## VOGTLE PLANTS 3&4 COSTS

| **A. STATEMENT OF COSTS (SOC) for OCTOBER 2017** | | **ITD** | **Current** |
|---|---|---|---|
| **Section Ref** | **Summary** | **Amount** | **Amount Due** |
| 1.0 | Total Labor Cost | 9,749.86 | 9,749.86 |
| 2.0 | Total Multiplier / ODC | 5,184.93 | 5,184.93 |
| 6.0 | Total Non-Labor Cost | 5,832.79 | 5,832.79 |
| **STATEMENT OF COSTS TOTAL** | | **20,767.58** | **20,767.58** |
| **B. MONTHLY FUNDS REQUEST (MFR) for October 2017** | | | 25,000.00 |
| **C. NET of SOC and MFR (A - B)** | | | (4,232.42) |
| **D. TOTAL AMOUNT DUE (or OWED)** (SOC less prior MFR) | | | **(4,232.42)** **USD** |

For Billing Inquiries, Please Contact:
Rob Smith at (xxx) xxx-xxx

**Level 2 - Bechtel Confidential**
For Authorized Parties Who Require the Information to do Bechtel Work

Page 2

# Exhibit P – Form of Invoice

## SUMMARY SCHEDULE OF CHARGES

Job: 26139
Invoice No:26139-1710XXX

| Labor SectionDescription | Schedule Reference | Total Hours | Total Amoun |
|---|---|---|---|
| **1.0Labor Cost** | | | |
| 1.1 Bechtel Labor Costs | | | |
| Straight Time | SCHD 2A Col 1 | 117.0 | 6,366. |
| Over Time | SCHD 2A Col 2 | 7.0 | 357. |
| Other Wages | SCHD 2A Col 4 | | 0.( |
| Payroll Additives | SCHD 2A Col 5 | | 3,025. |
| 1.1 Total Bechtel Labor Costs | | 124.0 | 9,749. |
| **1.0Total Labor Costs** | | **124.0** | **9,749** |
| **2.0Multiplier / ODC Rate** | | | |
| 2.1 Bechtel Multiplier | | | |
| Bechtel Multiplier 50% | SCHD 2A Col 6 | 0.0 | 4,874. |
| 2.2 Bechtel ODC Rate | | | |
| Bechtel ODC Rate $2.50 | SCHD 2A Col 7 | 0.0 | 310. |
| **2.0 Total Multiplier / ODC** | | | **5,184** |
| **6.0Non Labor Cost** | | | |
| 6.1 Non Labor Costs | | | |
| Non Labor Costs | SCHD 3 Col 1 | 0.0 | 5,832. |
| **6.0 Total Non Labor Cost** | | **0.0** | **5,832** |
| **9.0 Total Amount Due** | | **124.0** | **20,767** |



Job: 26139
Invoice No: 26139-1710XXX

SCHEDULE 2A
LABOR ABSTRACT

| Employee Name | Emp No | Gr | Org | PPE Date | ST Hours | OT Hours | Hrly Rate | (1) ST Wages | (2) OT Wages | (3) PT Wages | (4) Other Wages | (5) Pay Adds | (6) Multiplier | Mult Rate | Entered Amount | Exchg Rate | Ent Cur | USD Billing Amount | (7) USD ODC Rate | Total USD Billing Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Smith, Bob | 123456 | 22 | [illegible] | 1 Oct 17 | 74.0 | 0.0 | 68.06 | 5,373.15 | 0.00 | 0.00 | 0.00 | 1,519.53 | 2,916.08 | 60.00 | 8,741.94 | 1.0000 | USD | 8,741.94 | 177.50 | 8,919.44 |
| Jones, Ann | 234567 | 23 | [illegible] | 1 Oct 17 | 2.0 | 0.0 | 84.75 | 169.50 | 0.00 | 0.00 | 0.00 | 54.60 | 107.75 | 50.00 | 336.66 | 1.0000 | USD | 336.66 | 5.00 | 341.66 |
| Baker, Sue | 987654 | 25 | [illegible] | 1 Oct 17 | 41.0 | 7.0 | 51.12 | 2,2[illegible] | 567.84 | 0.00 | 0.00 | 1,110.35 | 1,308.72 | 60.00 | 5,576.17 | 1.0000 | USD | 5,576.17 | 127.50 | 5,703.67 |
| | | | | | | | | | | | | | | | 0.00 | 1.0000 | USD | - | | |
| | | | | | | | | | | | | | | | 0.00 | 1.0000 | USD | - | | |
| | | | | | | | | | | | | | | | 0.00 | 1.0000 | USD | - | | |
| | | | | | 117.0 | 7.0 | | [illegible] | 567.84 | 0.00 | 0.00 | [illegible] | 4,374.06 | 160.00 | 14,624.70 | | | 14,624.70 | 310.00 | 14,934.70 |

# Exhibit P – Form of Invoice

Page 4

Job: 26139
Invoice No: 26139-1710XXX

**SCHEDULE 26.1**
**OTHER WAGES DETAILS**

| Employee Name | PPE Date | Double Triple OT | Incentive Pymts | Temp Assignmt | Living Allow | Goods and Services | Housing Allow | Transport. Allow | Statutory Comp | Per Diem | Reloc Allow | Misc Pymts | Shift Premium | Entered Amount | Exchg Rate | Ent Cur | Billing Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | | 0.00 | 0.00 | 0.00 | 0.00 | 1.00 | USD | 0.00 |
| | | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | | | 0.00 |

Page 5

Job: 26139
Invoice No: 26139-1710XXX

**SCHEDULE 3**
**NON LABOR ABSTRACT**

| Source Reference | Transaction Date | Nat Class | Line Item Description | Hrs | Entered Amount | Exchg Rate | Ent Cur | (1) Billing Amount | Total Amount |
|---|---|---|---|---|---|---|---|---|---|
| **Business Travel-Regular (66*)** | | | | | | | | | |
| 987654 52778 | 10/20/17 | 660 | BAKER, SUE/987654 | 0.0 | 199.50 | 1.0000 | USD | 199.50 | 199.50 |
| 987654 52800 | 10/20/17 | 660 | BAKER, SUE/987654 | 0.0 | 2,903.63 | 1.0000 | USD | 2,903.63 | 2,903.63 |
| 123456 51346 | 10/20/17 | 660 | SMITH, BOB/123456 | 0.0 | 1,369.53 | 1.0000 | USD | 1,369.53 | 1,369.53 |
| 123456 52783 | 10/20/17 | 660 | SMITH, BOB/123456 | 0.0 | 1,360.13 | 1.0000 | USD | 1,360.13 | 1,360.13 |
| | | | **Business Travel-Regular Sub Total** | **0.0** | **5,832.79** | | | **5,832.79** | **5,832.79** |
| | | | **Grand Total** | **0.0** | **5,832.79** | | | **5,832.79** | **5,832.79** |

## Exhibit Q – Lien Waivers

## Form of Subcontractor’s Lien Waiver – Interim

**See Attached**

**Exhibit Q – Lien Waivers**

**INTERIM LIEN WAIVER AND RELEASE UPON PAYMENT**

**STATE OF GEORGIA**

**COUNTY OF BURKE**

**THE UNDERSIGNED SUBCONTRACTOR, MECHANIC, AND/OR MATERIALMAN HAS BEEN EMPLOYED BY BECHTEL POWER CORPORATION ("CONTRACTOR") TO FURNISH THE FOLLOWING LABOR, SERVICES, OR MATERIALS** [INSERT DESCRIPTION OF LABOR, SERVICES, OR MATERIALS] **FOR THE CONSTRUCTION OF IMPROVEMENTS KNOWN AS VOGTLE UNITS 3 AND 4 AT THE VOGTLE ELECTRIC GENERATING PLANT WHICH IS LOCATED IN THE CITY OF WAYNESBORO, COUNTY OF BURKE, STATE OF GEORGIA, AND IS OWNED BY GEORGIA POWER COMPANY, OGLETHORPE POWER CORPORATION (AN ELECTRIC MEMBERSHIP CORPORATION), MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA, MEAG POWER SPVJ, LLC, MEAG POWER SPVM, LLC, MEAG POWER SPVP, LLC, AND THE CITY OF DALTON, GEORGIA ACTING BY AND THROUGH ITS BOARD OF WATER, LIGHT AND SINKING FUND COMMISSIONERS AND MORE PARTICULARLY DESCRIBED AS FOLLOWS:**

**ADDITIONAL UNITS PROPERTY**

**ALL THAT TRACT OR PARCEL OF LAND LYING AND BEING IN THE 66TH GEORGIA MILITIA DISTRICT, BURKE COUNTY, GEORGIA, BEING MORE PARTICULARLY DESCRIBED AS FOLLOWS:**

**BEGINNING AT POINT HAVING PLANT VOGTLE PLANT GRID SYSTEM COORDINATES OF NORTH 9500 FEET, EAST 5000 FEET; THENCE RUNNING EAST TO THE POINT HAVING PLANT VOGTLE PLANT GRID SYSTEM COORDINATES OF NORTH 9500 FEET, EAST 8500 FEET; THENCE RUNNING SOUTH TO THE POINT HAVING PLANT VOGTLE PLANT GRID SYSTEM COORDINATES OF NORTH 5500 FEET, EAST 8500 FEET; THENCE RUNNING SOUTHWEST TO THE POINT HAVING PLANT VOGTLE PLANT GRID SYSTEM COORDINATES OF NORTH 5000 FEET, EAST 8000 FEET; THENCE RUNNING WEST TO THE POINT HAVING PLANT VOGTLE PLANT GRID SYSTEM COORDINATES OF NORTH 5000 FEET, EAST 5000 FEET; THENCE RUNNING NORTH TO THE POINT HAVING PLANT VOGTLE PLANT GRID SYSTEM COORDINATES OF NORTH 9500 FEET, EAST 5000 FEET, AND THE POINT OF BEGINNING. PLANT VOGTLE PLANT GRID SYSTEM COORDINATES CAN BE CONVERTED TO GEORGIA STATE PLANE COORDINATES [EAST ZONE] AS FOLLOWS: PLANT VOGTLE PLANT GRID SYSTEM NORTH+ 1,135,000 FEET = STATE NORTH; PLANT VOGTLE PLANT GRID SYSTEM EAST+ 614,000 FEET = STATE EAST; ALL AS SHOWN ON SOUTHERN NUCLEAR OPERATING COMPANY, INC. DRAWING NO. AR01-0000-X2-0004, VERSION 1.0, JOB NO. 25144, DATED FEBRUARY 22, 2006.**

**Exhibit Q – Lien Waivers**

**UPON RECEIPT OF THE SUM OF [INSERT PAYMENT AMOUNT] THE UNDERSIGNED SUBCONTRACTOR, MECHANIC, AND/OR MATERIALMAN WAIVES AND RELEASES ANY AND ALL LIENS OR CLAIMS OF LIENS IT HAS UPON THE FOREGOING DESCRIBED PROPERTY OR ANY RIGHTS AGAINST ANY LABOR AND/OR MATERIAL BOND THROUGH THE DATE OF [INSERT LAST DATE OF WORK COVERED BY INVOICE] , AND EXCEPTING THOSE RIGHTS AND LIENS THAT THE SUBCONTRACTOR, MECHANIC, AND/OR MATERIALMAN MIGHT HAVE IN ANY RETAINED AMOUNTS ON ACCOUNT OF LABOR OR MATERIALS, OR BOTH, FURNISHED BY SUBCONTRACTOR, MECHANIC, AND/OR MATERIALMAN TO OR ON ACCOUNT OF CONTRACTOR FOR SAID VOGTLE PROJECT AND PROPERTY.**

*[Signatures on following page]*

**Exhibit Q – Lien Waivers**

**GIVEN UNDER HAND AND SEAL THIS _____ DAY OF ____________, ______.**

**[INSERT NAME OF SUBCONTRACTOR, MECHANIC, AND/OR MATERIALMAN]**

**BY: ____________________________________________________ (SEAL)**

**PRINTED NAME: ________________________________________**

**TITLE: __________________________________________________**

**WITNESS: _______________________________________________**

**PRINTED NAME: _________________________________________**

**___________________________________________________________ (ADDRESS)**

**NOTICE: WHEN YOU EXECUTE AND SUBMIT THIS DOCUMENT, YOU SHALL BE CONCLUSIVELY DEEMED TO HAVE BEEN PAID IN FULL THE AMOUNT STATED ABOVE, EVEN IF YOU HAVE NOT ACTUALLY RECEIVED SUCH PAYMENT, 60 DAYS AFTER THE DATE STATED ABOVE UNLESS YOU FILE EITHER AN AFFIDAVIT OF NONPAYMENT OR A CLAIM OF LIEN PRIOR TO THE EXPIRATION OF SUCH 60 DAY PERIOD. THE FAILURE TO INCLUDE THIS NOTICE LANGUAGE ON THE FACE OF THE FORM SHALL RENDER THE FORM UNENFORCEABLE AND INVALID AS A WAIVER AND RELEASE UNDER O.C.G.A. SECTION 44-14-366.**

# Exhibit Q – Lien Waivers

## Form of Contractor's Lien Waiver – Interim

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**COUNTY OF BURKE**

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**ADDITIONAL UNITS PROPERTY**

**ALL THAT TRACT OR PARCEL OF LAND LYING AND BEING IN THE 66TH GEORGIA MILITIA DISTRICT, BURKE COUNTY, GEORGIA, BEING MORE PARTICULARLY DESCRIBED AS FOLLOWS:**

**BEGINNING AT POINT HAVING PLANT VOGTLE PLANT GRID SYSTEM COORDINATES OF NORTH 9500 FEET, EAST 5000 FEET; THENCE RUNNING EAST TO THE POINT HAVING PLANT VOGTLE PLANT GRID SYSTEM COORDINATES OF NORTH 9500 FEET, EAST 8500 FEET; THENCE RUNNING SOUTH TO THE POINT HAVING PLANT VOGTLE PLANT GRID SYSTEM COORDINATES OF NORTH 5500 FEET, EAST 8500 FEET; THENCE RUNNING SOUTHWEST TO THE POINT HAVING PLANT VOGTLE PLANT GRID SYSTEM COORDINATES OF NORTH 5000 FEET, EAST 8000 FEET; THENCE RUNNING WEST TO THE POINT HAVING PLANT VOGTLE PLANT GRID SYSTEM COORDINATES OF NORTH 5000 FEET, EAST 5000 FEET; THENCE RUNNING NORTH TO THE POINT HAVING PLANT VOGTLE PLANT GRID SYSTEM COORDINATES OF NORTH 9500 FEET, EAST 5000 FEET, AND THE POINT OF BEGINNING. PLANT VOGTLE PLANT GRID SYSTEM COORDINATES CAN BE**

**Exhibit Q – Lien Waivers**

**CONVERTED TO GEORGIA STATE PLANE COORDINATES [EAST ZONE] AS FOLLOWS: PLANT VOGTLE PLANT GRID SYSTEM NORTH+ 1,135,000 FEET = STATE NORTH; PLANT VOGTLE PLANT GRID SYSTEM EAST+ 614,000 FEET = STATE EAST; ALL AS SHOWN ON SOUTHERN NUCLEAR OPERATING COMPANY, INC. DRAWING NO. AR01-0000-X2-0004, VERSION 1.0, JOB NO. 25144, DATED FEBRUARY 22, 2006.**

**UPON RECEIPT OF THE SUM OF [INSERT PAYMENT AMOUNT] CONTRACTOR WAIVES AND RELEASES ANY AND ALL LIENS OR CLAIMS OF LIENS IT HAS UPON THE FOREGOING DESCRIBED PROPERTY OR ANY RIGHTS AGAINST ANY LABOR AND/OR MATERIAL BOND THROUGH THE DATE OF [INSERT LAST DATE OF WORK COVERED BY INVOICE] , AND EXCEPTING THOSE RIGHTS AND LIENS THAT CONTRACTOR MIGHT HAVE IN ANY RETAINED AMOUNTS ON ACCOUNT OF LABOR OR MATERIALS, OR BOTH, FURNISHED BY CONTRACTOR TO OR ON ACCOUNT OF OWNERS FOR SAID VOGTLE PROJECT AND PROPERTY.**

*[Signatures on following page]*

**Exhibit Q – Lien Waivers**

**GIVEN UNDER HAND AND SEAL THIS _____ DAY OF ___________, ______.**

**BECHTEL POWER CORPORATION**

**BY: ____________________________________________________ (SEAL)**

**PRINTED NAME: _______________________________________**

**TITLE: _________________________________________________**

**WITNESS: ______________________________________________**

**PRINTED NAME: ________________________________________**

**_________________________________________________________ (ADDRESS)**

**NOTICE: WHEN YOU EXECUTE AND SUBMIT THIS DOCUMENT, YOU SHALL BE CONCLUSIVELY DEEMED TO HAVE BEEN PAID IN FULL THE AMOUNT STATED ABOVE, EVEN IF YOU HAVE NOT ACTUALLY RECEIVED SUCH PAYMENT, 60 DAYS AFTER THE DATE STATED ABOVE UNLESS YOU FILE EITHER AN AFFIDAVIT OF NONPAYMENT OR A CLAIM OF LIEN PRIOR TO THE EXPIRATION OF SUCH 60 DAY PERIOD. THE FAILURE TO INCLUDE THIS NOTICE LANGUAGE ON THE FACE OF THE FORM SHALL RENDER THE FORM UNENFORCEABLE AND INVALID AS A WAIVER AND RELEASE UNDER O.C.G.A. SECTION 44-14-366.**

**Exhibit Q – Lien Waivers**

**Form of Subcontractor's Lien Waiver – Final**

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**LIEN WAIVER AND RELEASE UPON FINAL PAYMENT**

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**COUNTY OF BURKE**

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*[Signatures on following page]*

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**GIVEN UNDER HAND AND SEAL THIS _____ DAY OF ____________, ______.**

**[INSERT NAME OF SUBCONTRACTOR, MECHANIC, AND/OR MATERIALMAN]**

**BY: ____________________________________________________ (SEAL)**

**PRINTED NAME: ________________________________________**

**TITLE: __________________________________________________**

**WITNESS: _______________________________________________**

**PRINTED NAME: _________________________________________**

**__________________________________________________________ (ADDRESS)**

**NOTICE: WHEN YOU EXECUTE AND SUBMIT THIS DOCUMENT, YOU SHALL BE CONCLUSIVELY DEEMED TO HAVE BEEN PAID IN FULL THE AMOUNT STATED ABOVE, EVEN IF YOU HAVE NOT ACTUALLY RECEIVED SUCH PAYMENT, 60 DAYS AFTER THE DATE STATED ABOVE UNLESS YOU FILE EITHER AN AFFIDAVIT OF NONPAYMENT OR A CLAIM OF LIEN PRIOR TO THE EXPIRATION OF SUCH 60 DAY PERIOD. THE FAILURE TO INCLUDE THIS NOTICE LANGUAGE ON THE FACE OF THE FORM SHALL RENDER THE FORM UNENFORCEABLE AND INVALID AS A WAIVER AND RELEASE UNDER O.C.G.A. SECTION 44-14-366.**

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**COUNTY OF BURKE**

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**ADDITIONAL UNITS PROPERTY**

**ALL THAT TRACT OR PARCEL OF LAND LYING AND BEING IN THE 66TH GEORGIA MILITIA DISTRICT, BURKE COUNTY, GEORGIA, BEING MORE PARTICULARLY DESCRIBED AS FOLLOWS:**

**BEGINNING AT POINT HAVING PLANT VOGTLE PLANT GRID SYSTEM COORDINATES OF NORTH 9500 FEET, EAST 5000 FEET; THENCE RUNNING EAST TO THE POINT HAVING PLANT VOGTLE PLANT GRID SYSTEM COORDINATES OF NORTH 9500 FEET, EAST 8500 FEET; THENCE RUNNING SOUTH TO THE POINT HAVING PLANT VOGTLE PLANT GRID SYSTEM COORDINATES OF NORTH 5500 FEET, EAST 8500 FEET; THENCE RUNNING SOUTHWEST TO THE POINT HAVING PLANT VOGTLE PLANT GRID SYSTEM COORDINATES OF NORTH 5000 FEET, EAST 8000 FEET; THENCE RUNNING WEST TO THE POINT HAVING PLANT VOGTLE PLANT GRID SYSTEM COORDINATES OF NORTH 5000 FEET, EAST 5000 FEET;**

**Exhibit Q – Lien Waivers**

**THENCE RUNNING NORTH TO THE POINT HAVING PLANT VOGTLE PLANT GRID SYSTEM COORDINATES OF NORTH 9500 FEET, EAST 5000 FEET, AND THE POINT OF BEGINNING. PLANT VOGTLE PLANT GRID SYSTEM COORDINATES CAN BE CONVERTED TO GEORGIA STATE PLANE COORDINATES [EAST ZONE] AS FOLLOWS: PLANT VOGTLE PLANT GRID SYSTEM NORTH+ 1,135,000 FEET = STATE NORTH; PLANT VOGTLE PLANT GRID SYSTEM EAST+ 614,000 FEET = STATE EAST; ALL AS SHOWN ON SOUTHERN NUCLEAR OPERATING COMPANY, INC. DRAWING NO. AR01-0000-X2-0004, VERSION 1.0, JOB NO. 25144, DATED FEBRUARY 22, 2006.**

UPON RECEIPT OF THE SUM OF [INSERT PAYMENT AMOUNT] CONTRACTOR WAIVES AND RELEASES ANY AND ALL LIENS OR CLAIMS OF LIENS IT HAS UPON THE FOREGOING DESCRIBED PROPERTY OR ANY RIGHTS AGAINST ANY LABOR AND/OR MATERIAL BOND ON ACCOUNT OF LABOR OR MATERIALS, OR BOTH, FURNISHED BY THE UNDERSIGNED TO OR ON ACCOUNT OF OWNERS FOR SAID PROPERTY.

*[Signatures on following page]*

**Exhibit Q – Lien Waivers**

**GIVEN UNDER HAND AND SEAL THIS _____ DAY OF ____________, ______.**

**<u>BECHTEL POWER CORPORATION</u>**

**BY: ____________________________________________________ (SEAL)**

**PRINTED NAME: _______________________________________**

**TITLE: _________________________________________________**

**WITNESS: ______________________________________________**

**PRINTED NAME: ________________________________________**

**_________________________________________________________ (ADDRESS)**

**NOTICE: WHEN YOU EXECUTE AND SUBMIT THIS DOCUMENT, YOU SHALL BE CONCLUSIVELY DEEMED TO HAVE BEEN PAID IN FULL THE AMOUNT STATED ABOVE, EVEN IF YOU HAVE NOT ACTUALLY RECEIVED SUCH PAYMENT, 60 DAYS AFTER THE DATE STATED ABOVE UNLESS YOU FILE EITHER AN AFFIDAVIT OF NONPAYMENT OR A CLAIM OF LIEN PRIOR TO THE EXPIRATION OF SUCH 60 DAY PERIOD. THE FAILURE TO INCLUDE THIS NOTICE LANGUAGE ON THE FACE OF THE FORM SHALL RENDER THE FORM UNENFORCEABLE AND INVALID AS A WAIVER AND RELEASE UNDER O.C.G.A. SECTION 44-14-366.**

**Exhibit Q – Lien Waivers**

**Form of Contractor's Affidavit - Final**

**See Attached**

**Exhibit Q – Lien Waivers**

**CONTRACTOR'S AFFIDAVIT AND REPRESENTATIONS**

**[INSERT DATE]**

The undersigned ________________________, ________________________ of Bechtel Power Corporation ("Contractor") does hereby certify and warrant as follows:

1. All Parties Paid. Pursuant to the terms of the Construction Completion Agreement between Contractor and Georgia Power Company ("GPC"), for itself and as agent for Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and The City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners (collectively, "Owners"), dated as of _____________, 2017 (the "Agreement"), Contractor represent that, upon Contractor's receipt of the final payment in the amount of $[______________], invoiced to Owners on [______________], (i) Contractor will have received full, complete, and final payment for any and all materials, equipment, services and labor furnished by Contractor to or for the benefit of the Vogtle Project (the "Work"), and (ii) Subcontractors supplying labor or materials to Contractor in connection with the Work and the Vogtle Project have been paid in full, or will be paid in full promptly from the proceeds of this payment pursuant to the terms of those parties' respective agreements with Contractor for labor, services, equipment or materials furnished in relation to the Work and the Vogtle Project.

2. Waiver of Lien Claims. Upon Contractor's receipt of the final payment in the amount of $[______________], invoiced to Owners on [______________], Contractor waives any and all liens, and releases and forever discharges Owners, any construction lender, each and all of their respective directors, officers, principals, partners, employees, agents, subsidiaries, parent and related firms, successors, insurers, lenders, sureties, and assigns from any and all actions, causes of action, liens, bond rights, stop notices, debts, dues, accounts, covenants, agreements, judgments, claims, and demands of whatsoever nature or character for nonpayment for the Work for which payment is owed and is being made pursuant to the Agreement.

3. Representations. Contractor represents that with regard to each Subcontract with a total current value in excess of $150,000.00, Contractor has secured from such Subcontractor a waiver of lien rights in the form attached to the Agreement as Exhibit ___, with respect to services, labor, materials and/or equipment supplied to or for the benefit of Owners and/or the Vogtle Project for which proper and acceptable invoices have been received from such Subcontractor and processed by Contractor.

4. Authorization. Contractor warrants that it is the sole owner of any and all lien claims related to the Work for which the subject payment is owed, that it has not sold, assigned or conveyed such lien claims to any other party, and that the individual whose signature appears below has personal knowledge of these matters and is fully authorized and qualified to make these representations on behalf of Contractor.

**Exhibit Q – Lien Waivers**

5. Scope of Lien Release . The representations and lien release contained herein are independent covenants and operate, and are effective with respect to, labor, services, materials, or equipment provided to the Project or the Property by or through Contractor, under the Agreement, whether modified orally or in writing, and whether extra or additional to the Agreement.

**GIVEN UNDER HAND AND SEAL THIS _____ DAY OF ____________, ______.**

Signed, sealed, and delivered ____(SEAL)__
this ___day of __________, 2017. Name: __________

________________________________
Notary Public

[NOTARIAL SEAL]

My Commission Expires: ____________________

**Exhibit R - Parent Company Guarantee**

# GUARANTEE

THIS Guarantee ("Guarantee"), dated and effective as of ________ 2017, is made and entered into by BECHTEL NUCLEAR, SECURITY & ENVIRONMENTAL, INC., a Delaware corporation (the "Guarantor"), in favor of GEORGIA POWER COMPANY, a Georgia corporation, OGLETHORPE POWER CORPORATION (AN ELECTRIC MEMBERSHIP CORPORATION), an electric membership corporation formed under the laws of the State of Georgia, MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA, a public body corporate and politic and an instrumentality of the State of Georgia, MEAG POWER SPVJ, LLC, MEAG POWER SPVM, LLC, MEAG POWER SPVP, LLC, each a Georgia limited liability company, and THE CITY OF DALTON, GEORGIA, an incorporated municipality in the State of Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners (collectively, the "Beneficiary"). Individually, the Guarantor and Beneficiary may be referred to as a "Party" and together the "Parties."

**WHEREAS** , Georgia Power Company, for itself and as agent for Oglethorpe Power Corporation (An Electric Membership Corporation), Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and The City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners , on the one hand, and Bechtel Power Corporation, a subsidiary of the Guarantor ("Contractor"), on the other hand, have entered into that certain Construction Completion Agreement with respect to the completion of construction of Units 3 & 4 at the Vogtle plant site, dated as of _____________, 2017, including without limitation the Exhibits attached thereto (as may be amended, extended, supplemented, or restated, the "Agreement");

**WHEREAS** , the Agreement requires the Guarantor to deliver this Guarantee to the Beneficiary; and

**WHEREAS** , the Guarantor expects to derive substantial direct and indirect benefit from the transactions contemplated by the Agreement.

**NOW, THEREFORE** , for and in consideration of the foregoing premises, the mutual agreements contained herein and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Guarantor agrees as follows:

## ARTICLE 1 - RESERVED

## ARTICLE 2 - GUARANTEE

2.1 *Guarantee.* Guarantor hereby unconditionally and irrevocably guarantees to the Beneficiary and its successors and permitted assigns, upon the terms and conditions herein, the prompt and full payment, when due and owing, of all amounts now and/or hereafter due to be paid by the Contractor under the Agreement, including without limitation payment of all damages arising from any breach by Contractor of its obligations under the Agreement, all with such interest as may accrue under the Agreement (collectively, whether now or hereafter existing or arising, the "Guaranteed Obligations"). If Contractor fails to pay any Guaranteed Obligations when due, then

**Exhibit R - Parent Company Guarantee**

Guarantor will immediately pay such Guaranteed Obligations following written notice in accordance with this Guarantee and subject to the terms and conditions provided herein.

2.2 *Guarantee Absolute.* (a) Guarantor absolutely guarantees that the Guaranteed Obligations will be paid strictly in accordance with the terms of the Agreement, regardless of any law, rule or regulation now or hereafter in effect in any jurisdiction affecting any of such terms or the obligations of Contractor or any rights of the Beneficiary with respect thereto, including, without limitation any bankruptcy, restructuring, insolvency or reorganization laws, rules or regulations. Without limiting the foregoing, any bankruptcy or insolvency or related discharge or release of Contractor shall not affect the Guarantor's obligations hereunder. This Guarantee constitutes a guarantee of payment and not of collection. The obligations of the Guarantor hereunder are several from the Contractor or any other person and are primary obligations concerning which the Guarantor is the principal obligor. The liability of Guarantor under this Guarantee shall be direct and immediate and not conditional or contingent upon the pursuit of any rights or remedies against the Contractor or any other person, but subject to Section 2.3(e) hereof, or against securities or liens available to the Beneficiary or its successors or permitted assigns.

(b) Notwithstanding anything to the contrary herein, as a condition to enforcement of this Guarantee against Guarantor, Beneficiary shall be required to show: (i) a copy of the written notice sent by Beneficiary or its authorized representative to the Contractor before making the claim under this Guarantee, specifying the amount of the payment (including without limitation any damages) not paid by Contractor and requesting the Contractor to pay the same (except that no such notice to the Contractor shall be required as a condition to enforcement of this Guarantee against Guarantor if the Contractor and/or its assets are the subject of a bankruptcy, insolvency or similar proceeding); and (ii) a letter signed by Beneficiary's authorized representative certifying that the Contractor has failed to remedy the non-payment within any applicable cure period set forth in the Agreement.

(c) The liability of the Guarantor under this Guarantee shall, subject to Section 2.2(b) and Section 2.3(e) hereof, be irrevocable, absolute and unconditional irrespective of, and the Guarantor hereby irrevocably waives any defenses and/or rights of discharge it may now have or hereafter acquire in any way relating to, any or all of:

> (i) any change in the time, manner or place of payment of, or in any other term of, all or any of the Agreement (including any of the Guaranteed Obligations), or any other amendment, extension, supplement, restatement, modification or waiver of, or any renewal, discharge, release, compromise, subordination or consent to departure from, the terms of such Agreement (including any of the Guaranteed Obligations);
>
> (ii) any change, restructuring or termination of the corporate structure or existence of Guarantor, the Contractor or any of their respective subsidiaries;
>
> (iii) any lack of validity or enforceability of the Agreement (including any of the Guaranteed Obligations) or any agreement or instrument relating thereto;

**Exhibit R - Parent Company Guarantee**

(iv) any failure of the Beneficiary to disclose to either the Contractor or the Guarantor any information relating to the business, condition (financial or otherwise), operations, performance, properties or prospects of either the Contractor or any of its subsidiaries now or hereafter known to the Beneficiary (the Guarantor waiving any duty on the part of the Beneficiary to disclose such information);

(v) any taking or failure to take any action (including, without limitation, any lack of due diligence) by the Beneficiary in the collection or protection of or realization upon or otherwise in respect of any collateral securing the Agreement (including any of the Guaranteed Obligations);

(vi) any circumstance whatsoever or any act of the Beneficiary or any existence of or reliance on any representation by the Beneficiary that might otherwise constitute a legal or equitable defense available to, or a discharge of, the Guarantor; or

(vii) any waiver or release or exercise or refrain from exercising any rights or remedies against Contractor,

provided that Guarantor does not waive, and shall have the benefit of and reserves the right to assert, any defenses and/or rights of discharge available to the Contractor to the extent that any claims by Owners (as defined in the Agreement) against Contractor are released and/or otherwise compromised pursuant to a written agreement between authorized representatives of Contractor and Owners (as defined in the Agreement).

(d) This Guarantee shall continue to be effective or be reinstated, as the case may be, if at any time any payment of any of the Guaranteed Obligations is voided, rescinded or must otherwise be returned by the Beneficiary or any other person as a preference or fraudulent transfer or otherwise for any reason, including, without limitation, upon or after the insolvency, bankruptcy, or reorganization of the Contractor, all as though such payment had not been made. This Guarantee shall continue to be effective if Contractor or Guarantor merges or consolidates with or into another entity, loses its separate legal identity or if Contractor ceases to exist.

No action which the Beneficiary shall take or fail to take in connection with the Guaranteed Obligations, or any security for the payment or performance of any of the Guaranteed Obligations, nor any course of dealing with the Contractor or any other person, shall release Guarantor's obligations hereunder, affect this Guarantee in any way, or afford Guarantor any recourse against the Beneficiary.

(e) In the case of an event of default under the Agreement which has not been cured during any applicable cure period set forth in the Agreement, or with regard to the non-payment of any of the Guaranteed Obligations, Guarantor hereby consents and agrees that the Beneficiary shall have the right to enforce its rights, powers, and remedies thereunder or hereunder or under any other instrument now or hereafter evidencing, securing, or otherwise relating to the Guaranteed Obligations, and apply any payments or credits received from the Contractor or Guarantor or realized from any security, in any manner and in any order as the Beneficiary, in its sole discretion, shall see fit, and all rights, powers, and remedies available to the Beneficiary in such event shall be nonexclusive and cumulative of all other rights, powers, and remedies provided thereunder or hereunder or by law or in equity. If the Guaranteed Obligations are partially paid by reason of the election of the Beneficiary, its successors or permitted assigns, to pursue any of the remedies available to the Beneficiary, or if the Guaranteed Obligations are otherwise partially paid, this Guarantee shall nevertheless remain in full force and effect less any such amounts indefeasibly paid to the Beneficiary in permanent reduction of the Guaranteed Obligations, and Guarantor shall remain liable for the remaining balance of the Guaranteed Obligations even though any rights which Guarantor may have against the Contractor may be destroyed or diminished by the exercise of any such remedy.

*2.3 Waivers and Acknowledgments* . (a) Without prejudice to the requirement for notice set forth in Section 2.1 hereof and the requirements set forth in Section 2.2(b) hereof, Guarantor hereby waives promptness, diligence, presentment, demand of payment, acceptance, notice of acceptance, suretyship defenses, protest, notice of protest, notice of dishonor or default, notice of any sale of any collateral or security, notice of the release or discharge of any person or collateral and any other notices with respect to the Agreement (including any of the Guaranteed Obligations) and/or this Guarantee.

(b) The Guarantor hereby unconditionally and irrevocably waives all defenses based on suretyship.

(c) The Guarantor hereby unconditionally and irrevocably waives all rights to require Beneficiary to commence any action to collect any or all of the Guaranteed Obligations from the Contractor or any other person before demanding payment under this Guarantee, including, without limitation, all of its rights under the provisions of O.C.G.A. Section 10-7-24, as amended.

(d) The Guarantor hereby unconditionally and irrevocably waives any right to revoke this Guarantee and acknowledges that this Guarantee is continuing in nature and applies to all Guaranteed Obligations, whether existing now or in the future. The provisions of this Guarantee shall extend and be applicable to all renewals, amendments, extensions, restatements, consolidations, and modifications of the Agreement (including any of the Guaranteed Obligations).

(e) The Guarantor hereby unconditionally and irrevocably waives any defense based on any right of offset, set-off or counterclaim against or in respect of the obligations of the Guarantor hereunder; *provided* , *however* , notwithstanding anything to the contrary herein, (i) the liability of Guarantor shall be subject to the same limitations of liability and other liability protections applicable to the Contractor's obligations and liabilities under the express terms of the Agreement, and (ii) Guarantor shall have the full benefit of, and reserves the right to assert, any and all defenses, counterclaims, and set-off rights available to the Contractor with respect to any obligations and liabilities arising under the Agreement, except for defenses, counterclaims, and setoff rights (x) waived elsewhere in this Guarantee, (y) arising out of or related to bankruptcy, insolvency, reorganization, dissolution or liquidation of the Contractor or the power or authority of Contractor to enter into the Agreement or to perform its obligations thereunder, or (z) related to any lack of validity or enforceability of the Agreement, any Guaranteed Obligations or any other documents executed in connection with the Agreement (including any of the Guaranteed Obligations).

**Exhibit R - Parent Company Guarantee**

*2.4 Subrogation* . Notwithstanding any payment or payments or performance made by the Guarantor hereunder, the Guarantor hereby irrevocably waives any and all rights of subrogation to the rights of the Beneficiary against the Contractor and any and all rights of reimbursement, assignment, indemnification or implied contract or any similar rights (including without limitation any statutory rights of subrogation under Section 509 of the Bankruptcy Code, 11 U.S.C. § 509) against the Contractor until such time as all of the Guaranteed Obligations have been indefeasibly paid in full. If, notwithstanding the foregoing, any amount shall be paid to the Guarantor on account of such subrogation or similar rights at any time when all of the Guaranteed Obligations shall not have been indefeasibly paid in full, such amount shall be held by the Guarantor in trust for the Beneficiary and shall be turned over to the Beneficiary in the exact form received by the Guarantor, to be applied against the Guaranteed Obligations in such order as the Beneficiary may determine in its sole discretion.

2.5 *Payments Free and Clear* . (a) All payments under this Guarantee shall be made in immediately available U.S. Dollars and without any deduction or withholding for or on account of any tax imposed upon Beneficiary or the Guarantor unless such deduction or withholding is required by any applicable law, as modified by the practice of any relevant governmental revenue authority, then in effect. If the Guarantor is so required to deduct or withhold, then the Guarantor will (i) pay to the relevant authorities the full amount required to be deducted or withheld (including the full amount of tax required to be deducted or withheld from any additional amount paid by the Guarantor to the Beneficiary under this Section 2.5) promptly upon the earlier of determining that such deduction or withholding is required or receiving notice that such an amount has been assessed against the Beneficiary, and in any event before penalties attach thereto or interest accrues thereon, (ii) promptly forward to the Beneficiary an official receipt (or certified copy), or other documentation reasonably acceptable to the Beneficiary, evidencing such payment to such authorities and, (iii) in addition to the payment which the Beneficiary is otherwise entitled under this Guarantee, if such withholding is on account of any tax imposed upon Guarantor, pay to the Beneficiary such additional amount as is necessary to ensure that the net amount actually received by the Beneficiary (free and clear of taxes assessed against the Guarantor) will equal the full amount the Beneficiary would have received had no such deduction or withholding been required.

(b) If (i) the Guarantor is required to make any deduction or withholding on account of any tax from any payment made by it under this Guarantee, (ii) the Guarantor does not make the deduction or withholding, and (iii) a liability for or on account of the tax is therefore assessed directly against the Beneficiary, the Guarantor shall pay to the Beneficiary, promptly after demand, the amount of the liability (including any related liability for interest or penalties).

## ARTICLE 3 - REPRESENTATIONS AND WARRANTIES

The Guarantor hereby represents and warrants to Beneficiary as of the effective date of this Guarantee as follows:

**Exhibit R - Parent Company Guarantee**

3.1 *Organization* . The Guarantor is a corporation duly organized, validly existing and in good standing under the laws of Delaware.

3.2 *Authorization; No Conflict* . The execution and delivery by the Guarantor of this Guarantee and the performance by the Guarantor of its obligations hereunder (i) are within the Guarantor's corporate powers, (ii) have been duly authorized by all necessary corporate action, do not contravene its organizational documents or any agreement, law or regulation applicable to or binding on the Guarantor or any of its properties, (iii) do not require any filings be made or notices be given which have not been made or given, and (iv) do not require the consent or approval of any person which has not already been obtained or the satisfaction or waiver of any conditions precedent to the effectiveness of this Guarantee that have not been satisfied or waived.

3.3 *Enforceability* . This Guarantee constitutes the legal, valid and binding obligation of the Guarantor enforceable against the Guarantor in accordance with its terms, except to the extent that such enforceability may be limited by applicable bankruptcy, insolvency, dissolution, reorganization, moratorium, liquidation or other similar laws affecting creditors' rights generally and by general principles of equity (regardless of whether enforcement is sought in a proceeding in equity or at law).

3.4 *No Bankruptcy Proceedings* . There are no bankruptcy proceedings pending or being contemplated by Guarantor or, to its knowledge, threatened against it.

3.5 *No Legal Proceedings* . There are no legal proceedings that would be reasonably likely to materially adversely affect Guarantor's ability to perform this Guarantee.

3.6 *Subsidiary.* Contractor is a direct or indirect subsidiary of Guarantor.

3.7 *Execution.* The person executing this Guarantee below on behalf of Guarantor is duly authorized and empowered to execute and deliver this Guarantee on behalf of Guarantor.

ARTICLE 4 - MISCELLANEOUS

4.1 *Continuing Guarantee; Assignment* . This Guarantee is a continuing Guarantee and shall (i) remain in full force and effect until all of the Guaranteed Obligations, whenever arising, have been indefeasibly paid and satisfied in full, (ii) consistent with the terms hereof, apply to all Guaranteed Obligations whenever arising, (iii) be binding upon the Guarantor and its successors and assigns, and (iv) inure to the benefit of, and be enforceable by, the Beneficiary and its permitted assigns hereunder; provided that (A) no permitted assignment or other transfer by, through or under the Beneficiary shall operate to increase Guarantor's obligations hereunder, and (B) Guarantor shall receive full credit for any final, indefeasible payments made by it to the Beneficiary, its successors and permitted assigns with respect to the Guaranteed Obligations prior to the time Guarantor receives written notice of such assignment or succession. The Beneficiary may assign its rights or obligations under this Guarantee to any person to whom the benefit of the Agreement is assigned, without the prior written consent of the Guarantor. The Guarantor may not assign or delegate its rights or obligations under this Guarantee without (x) the prior written consent of the Beneficiary, which consent may be withheld in the Beneficiary's sole discretion, and (y) a written assignment and assumption agreement in form and substance reasonably acceptable to the Beneficiary.

4.2 *Survival.* Without prejudice to the survival of any of the other agreements of the Guarantor under this Guarantee, the agreements and obligations of the Guarantor contained in Sections 2.2(d), 2.5 and 4.5 shall survive the final, indefeasible payment in full of the Guaranteed Obligations and all of the other amounts payable under this Guarantee.

4.3 *Notices* . All notices, requests, demands and other communications which are required or may be given under this Guarantee shall be in writing and shall be deemed to have been duly given when actually received if (a) personally delivered; (b) transmitted by facsimile, electronic or digital transmission method; or (c) if sent by certified or registered mail, return receipt requested. In each case notice shall be sent:

(i) if to the Beneficiary:

Georgia Power Company
[ ]
Attention: [ ]

(ii) if to the Guarantor:

Bechtel Nuclear, Security & Environmental, Inc.
[ ]
Attention: [ ]

4.4 *Delay and Waiver* . No failure on the part of the Beneficiary to exercise, and no delay in exercising, any right hereunder shall operate as a waiver thereof; nor shall any single or partial exercise of any right hereunder preclude any other or further exercise thereof or the exercise of any other right. The remedies herein provided are cumulative and not exclusive of any remedies provided by law.

4.5 *Expenses* . Guarantor agrees to pay or reimburse the Beneficiary and any permitted assigns of the Beneficiary for its reasonable costs, charges and expenses (including reasonable fees and expenses of counsel) incurred in connection with and to the extent of the proper enforcement and/or collection of this Guarantee or occasioned by any non-payment of the Guaranteed Obligations or other breach by the Guarantor of any of its obligations under this Guarantee. The Beneficiary agrees to pay or reimburse Guarantor for its reasonable costs, charges and expenses (including reasonable fees and expenses of counsel) incurred in connection with defending legal proceedings brought by the Beneficiary to enforce this Guarantee if Guarantor prevails in such legal proceedings.

**Exhibit R - Parent Company Guarantee**

4.6 *Entire Agreement; Amendments* . This Guarantee and any agreement, document or instrument attached hereto or referred to herein integrate all the terms and conditions mentioned herein or incidental hereto and supersede all oral negotiations and prior writings in respect to the subject matter hereof. In the event of any conflict between the terms, conditions and provisions of this Guarantee and any such agreement, document or instrument, the terms, conditions and provisions of this Guarantee shall prevail. This Guarantee may only be amended or modified by an instrument in writing specifically referencing this Guarantee signed by each of the Guarantor and the Beneficiary and any permitted assigns of the Beneficiary.

4.7 *Headings* . The headings of the various Sections of this Guarantee are for convenience of reference only and shall not modify, define or limit any of the terms or provisions hereof.

4.8 *Governing Law* . This Guarantee shall be construed and interpreted, and the rights of the Parties determined, in accordance with the law of the State of Georgia without giving effect to principles of conflicts of law that would require the application of the laws of another jurisdiction.

4.9 *Disputes.*

(a) Waiver of Right to Trial by Jury . Each Party irrevocably waives any and all rights to trial by jury with respect to any and all disputes arising out of or in connection with this Guarantee, including disputes regarding the interpretation, scope or validity of this Guarantee or any alleged breach of any provision contained herein or any money owed hereunder (a “Dispute”).

(b) Consent to Jurisdiction and Service of Process . All judicial proceedings brought against Guarantor arising out of or relating to this Guarantee may be brought in the U.S. District Court for the Southern District of Georgia (or if such court does not have jurisdiction, the nearest court of the State of Georgia thereto with appropriate jurisdiction). By executing and delivering this Guarantee, Guarantor irrevocably (i) accepts generally and unconditionally the non-exclusive jurisdiction and venue of such court; (ii) waives any defense of *forum non conveniens* ; (iii) agrees that service of all process in any such proceeding in such court may be made by registered or certified mail, return receipt requested, to the Guarantor at its address for notices provided herein; (iv) agrees that Beneficiary retains the right to serve process in any other manner permitted by law or to bring proceedings against Guarantor in the courts of any other jurisdiction as may be permitted by law; and (v) without limiting the foregoing, also appoints and shall maintain Contractor as its agent for service of process.

4.10 *Severability* . Any provision of this Guarantee that shall be prohibited or unenforceable shall be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof.

IN WITNESS WHEREOF, the Guarantor has caused this Guarantee to be duly executed and delivered by its duly authorized representative as of the day and year first above written.

**Guarantor**

**Exhibit R - Parent Company Guarantee**

**BECHTEL NUCLEAR, SECURITY & ENVIRONMENTAL, INC.**

By: ___________________________________

Name:

Title:

**Exhibit S - Form of Confidentiality Agreement**

## CONFIDENTIALITY AGREEMENT

THIS CONFIDENTIALITY AGREEMENT (this "Agreement") is made as of the ___ day of _____________, 20__, by and between ___________________ (the "Disclosing Party') and ________________ (the "Recipient").

**WHEREAS** , the Disclosing Party is a party to the Construction Completion Agreement, dated as of _____________, between Georgia Power Company for itself and as agent for the Vogtle Owners (collectively "Owners") and Bechtel Power Corporation ("Bechtel") under which Bechtel will perform certain agreed-to services for Owners for the completion of the Vogtle 3 & 4 project ("Construction Completion Agreement"); and

**WHEREAS** , the Disclosing Party desires to disclose to Recipient certain confidential and/or proprietary information which is either marked as being confidential at the time of disclosure, or of a nature that the Recipient can reasonably be expected to ascertain the confidential nature of such information at the time of receipt (in either case, "Confidential and Proprietary Information") of Disclosing Party, Bechtel, Owners, Westinghouse Electric Company, LLC ("Westinghouse"), WECTEC Global Project Services Inc. ("WECTEC"), and/or another third party, as the case may be; and

**WHEREAS** , under the terms of the Construction Completion Agreement, the Disclosing Party and the Recipient are required to enter into this Agreement as a condition to disclosure of such Confidential and Proprietary Information to the Recipient.

**NOW THEREFORE** , for and in consideration of the premises and the mutual promises hereinafter set forth and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto hereby agree as follows:

1. Recipient shall maintain the confidentiality of all Confidential and Proprietary Information disclosed to it hereunder, and shall not use such Confidential and Proprietary Information for any purpose other than the purposes of construction, testing, completion and defense of ITAACs, startup, trouble-shooting, response to plant events, inspection, evaluation of system or component performance, scheduling, investigations, operation, maintenance, training, repair, licensing, modification, decommissioning and compliance with laws or the requirements of governmental authorities, in each case as it relates to the Vogtle 3&4 project (the "Purpose").

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[2] Owners are defined as Georgia Power Company, a Georgia Corporation, Oglethorpe Power Corporation (An Electric Membership Corporation), an electric membership corporation formed under the laws of the State of Georgia, Municipal Electric Authority of Georgia, a public body corporate and politic and an instrumentality of the State of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, each a Georgia limited liability company, and The City of Dalton, Georgia, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light and Sinking Fund Commissioners. Southern Nuclear Operating Company, Inc. ("SNC") is the licensed operator of Vogtle 3 and 4 and is Owners' agent for the purposes of implementation and administration of the Construction Completion Agreement.

**Exhibit S - Form of Confidentiality Agreement**

2. Recipient shall not transmit or further disclose such Confidential and Proprietary Information to any third party, including, without limitation, parent organizations of Recipient, sister organizations of Recipient, subsidiaries of Recipient, consultants of Recipient or subcontractors of Recipient, unless such third party has entered into a confidentiality agreement with Disclosing Party substantially in the form of this Agreement.

3. In the event that the Recipient or any of its representatives are requested or required in any proceeding or by any governmental authority to disclose any of the Confidential and Proprietary Information, the Recipient shall provide the Disclosing Party with prompt written notice of such request or requirement so that the Disclosing Party may seek a protective order or other appropriate remedy and/or waive compliance with the provisions of this Agreement. If, in the absence of a protective order or other remedy or the receipt of a waiver from the Disclosing Party, the Recipient or any of its representatives are nonetheless, in the written opinion of their counsel, legally compelled to disclose such information, it or its representatives may, without liability hereunder, disclose only that portion of the Confidential and Proprietary Information which such counsel advises the Recipient is legally required to be disclosed, provided that the Recipient exercises its reasonable efforts to preserve the confidentiality of the Confidential and Proprietary Information, including, without limitation, by cooperating with the Disclosing Party to obtain an appropriate protective order or other reliable assurance that confidential treatment will be accorded the Confidential and Proprietary Information.

4. Except where necessary in furtherance of the Purpose, Recipient shall not make any copy or in any way reproduce or excerpt such Confidential and Proprietary Information except as authorized by the Disclosing Party in writing prior to such reproduction or excerption. Any such copies or excerpts shall include all proprietary notices and designations. Upon the written request of the Disclosing Party, the Confidential and Proprietary Information provided hereunder and any such copies or excerpts thereof shall be returned to the Disclosing Party, or, at the sole option and request of the Disclosing Party, Recipient shall destroy such information and any such copies and/or excerpts and certify in writing to the Disclosing Party that such information has in fact been destroyed (but for a single copy retained for legal archival purposes, which shall continue to be subject to the provisions of this Agreement).

5. Nothing herein shall apply to any information which is:

(a) now generally known or readily available to the trade or public or which becomes so known or readily available without fault of the Recipient; or

(b) rightfully possessed by the Recipient without restriction prior to its disclosure hereunder by the Disclosing Party; or

(c) acquired from a third party without restriction, provided that the Recipient does not know, or have reason to know, or is not informed subsequent to disclosure by such third party and prior to disclosure by the Recipient that such information was acquired under an obligation of confidentiality.

**Exhibit S - Form of Confidentiality Agreement**

6. It is mutually understood that nothing herein shall be construed as granting or implying any right under any letters patent, or to use any Confidential and Proprietary Information claimed therein, or as permitting Recipient to unfairly obtain the right to use Confidential and Proprietary Information which becomes publicly known through an improper act or omission on its part.

7. Neither Owners, Bechtel, Westinghouse, WECTEC, nor their affiliates make any warranty or representation whatsoever to the Recipient as to the sufficiency or accuracy of the Confidential and Proprietary Information provided hereunder, the ability of Recipient to use the Confidential and Proprietary Information for its intended purpose, or as to the result to be obtained therefrom.

8. Neither Owners, Bechtel, Westinghouse, WECTEC, nor their affiliates, suppliers, or subcontractors of any tier shall be liable with respect to or resulting from the use (or the results of such use) or misuse of any Confidential and Proprietary Information furnished hereunder.

9. Nothing in this Agreement shall obligate the Disclosing Party to provide any specific information that it otherwise desires to withhold.

10. Recipient agrees to fully comply with all laws and regulations with regard to the Confidential and Proprietary Information transmitted hereunder.

11. Recipient shall not, at any time file, cause or authorize the filing of any patent application in any country in respect of any invention derived from the Confidential and Proprietary Information supplied hereunder.

12. Recipient shall not assign this Agreement. This Agreement shall be binding upon the Recipient and its successors and shall benefit and be enforceable by Owners, Bechtel, Westinghouse, or WECTEC and each of their respective successors and assigns.

13. If any of the terms of this Agreement are violated by Recipient, the Owners, Bechtel, Westinghouse, or WECTEC, as the case may be, shall be entitled to an injunction to be issued by any court of competent jurisdiction, enjoining and restraining the Recipient from such violation.

14. If any provision of this Agreement is held invalid in any respect, it shall not affect the validity of any other provision of this Agreement. If any provision of this Agreement is held to be unreasonable as to the time, scope or otherwise, it shall be construed by limiting and reducing it so as to be enforceable under then applicable law.

15. This Agreement shall be governed in accordance with the laws of the State of Georgia without giving effect to any choice of law, provision, or rule (whether of Georgia or any other jurisdiction) that would cause the application of the laws of any jurisdiction other than Georgia.

**Exhibit S - Form of Confidentiality Agreement**

**IN WITNESS WHEREOF** , the parties have hereto set their respective signatures to this Agreement.

**DISCLOSING PARTY** :

By: ____________________________

Name: ____________________________

Title: ____________________________

Address: ____________________________

____________________________

____________________________

**RECIPIENT** :

By: ____________________________

Name: ____________________________

Title: ____________________________

Address: ____________________________

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**Exhibit T - Lobbying Certificate**

**Certification for Contracts, Grants, Loans, and Cooperative Agreements**

The undersigned certifies, to the best of his or her knowledge and belief, that:

(1) No Federal appropriated funds have been paid or will be paid, by or on behalf of the undersigned, to any person for influencing or attempting to influence an officer or employee of any agency, a Member of Congress, an officer or employee of Congress, or an employee of a Member of Congress in connection with the awarding of any Federal contract, the making of any Federal grant, the making of any Federal loan, the entering into of any cooperative agreement, and the extension, continuation, renewal, amendment, or modification of any Federal contract, grant, loan, or cooperative agreement.

(2) If any funds other than Federal appropriated funds have been paid or will be paid to any person for influencing or attempting to influence an officer or employee of any agency, a Member of Congress, an officer or employee of Congress, or an employee of a Member of Congress in connection with this Federal contract, grant, loan, or cooperative agreement, the undersigned shall complete and submit Standard Form-LLL, "Disclosure Form to Report Lobbying," in accordance with its instructions.

(3) The undersigned shall require that the language of this certification be included in the award documents for all subawards at all tiers (including subcontracts, subgrants, and contracts under grants, loans, and cooperative agreements) and that all subrecipients shall certify and disclose accordingly.

This certification is a material representation of fact upon which reliance was placed when this transaction was made or entered into. Submission of this certification is a prerequisite for making or entering into this transaction imposed by section 1352, title 31, U.S. Code. Any person who fails to file the required certification shall be subject to a civil penalty of not less than $10,000 and not more than $100,000 for each such failure.

______________________________

Organization Name

______________________________

Name of Authorized Official

______________________________

Signature Date

# Exhibit U - Dispute Resolution Procedures

## Article 1. GENERAL

1.1. These Dispute Resolution Board Procedures ("DRB Procedures") specify the requirements for the DRB pursuant to Article 38 of the Construction Completion Agreement.

1.2. These DRB Procedures encompass: 1) general DRB requirements and authority; 2) regular meetings of the DRB with the Parties; 3) regular DRB hearings and determinations; 4) expedited DRB hearings and determinations; and 5) informal advisory DRB opinions. The Owners and the Contractor shall diligently cooperate with each other and with the DRB and shall perform such acts as may be necessary to obtain prompt, informed, cost-effective and expeditious resolution of any Contract Claim. These DRB Procedures do not modify the respective rights and duties of the Owners or the Contractor per the Construction Completion Agreement except as specifically provided herein.

1.3. Capitalized terms used herein are used as defined in the Construction Completion Agreement unless specifically indicated otherwise.

1.4. In the event that the Parties fail to resolve a Contract Claim, as determined by the Party asserting the Contract Claim, a Party may submit such Contract Claim to the DRB (as described in more detail below), with a copy to the other Parties.

1.5. Each Party agrees that its compliance with Article 38 and these DRB Procedures with regard to a Contract Claim is a condition precedent to such Party's commencing or pursuing any arbitration with respect to such Contract Claim.

1.6. To the extent a Party fails to submit to the authority of the DRB or fails to comply with these DRB Procedures, any such failure may be properly considered by the DRB as evidence that such Party's Contract Claim/position is not adequately supported.

1.7. "DRB Members" are the three members of the DRB, each of whom is a signatory to the DRB Member Agreement, as jointly selected by the Owners and the Contractor as provided herein, and any replacements of such DRB Members.

1.8. "DRB Member Agreement" is an agreement to which the individual DRB Members, the Owners, and the Contractor are parties, which establishes the DRB consistent with the requirements of these DRB Procedures.

1.9. "DRB Determination" means a written decision issued by the DRB on a Contract Claim submitted to it, either as a result of the Regular or Expedited hearing process. DRB Determinations shall be admissible in subsequent arbitration or other dispute resolution proceedings.

1.10. "DRB Proceeding" means the process that is commenced by submission of a Contract Claim to the DRB and that results in the issuance of a DRB Determination.

1.11. "Financial Interest" means any direct or indirect ownership interest, loans, receivables, or payables, except for holdings in mutual funds or exchange traded funds.

**Exhibit U - Dispute Resolution Procedures**

1.12. “Additional Project Parties” means past or present consultants, subconsultants, subcontractors and suppliers of all tiers engaged in connection with the Vogtle Units 3&4 project.

1.13. “Other Parties” means entities and individuals who have been engaged by any of the Owners or the Contractor in any capacity within the 10 years prior to September 30, 2017.

1.14. “Potential Conflict Parties” means, collectively, the Parties, the Additional Project Parties, the Other Parties, and the key individuals employed by each, as identified in a list compiled for this purpose by the Owners and Contractor.

1.15. Where applicable, the definition of “Contract Claim” as used in these DRB Procedures includes any related counterclaim that is asserted in accordance with these DRB Procedures.

Article 2. REQUIREMENTS FOR DRB MEMBERSHIP

2.1. Each prospective DRB Member shall individually represent that he/she is qualified and able to perform independently and impartially the duties set forth in Article 38 of the Construction Completion Agreement, these DRB Procedures and the DRB Member Agreement. It is imperative that DRB Members show no partiality to either the Contractor or the Owners, or have any conflict of interest. The DRB Members shall agree to abide by the Code of Ethics recommended by the Dispute Resolution Board Foundation.

2.2. Each DRB Member shall have the following professional experience and qualifications:

2.2.1 Experience with the interpretation and implementation of complex construction contracts and associated documents;

2.2.2 Experience in construction matters and the resolution of design and construction disputes relevant to the scope of work under the Construction Completion Agreement, and

2.2.3 Prior experience as a mediator or arbitrator with respect to complex construction disputes is preferred, but not required.

2.3. The DRB Chair shall also have administrative and dispute resolution experience and the ability to facilitate the DRB’s proceedings. It is also desirable for the DRB Chair to have substantial experience in construction dispute resolution, adjudication or arbitration, the interpretation of construction contract documents, and the analysis and resolution of construction disputes.

2.4. It is imperative that all members of the DRB be neutral, act impartially, and be free from any conflict of interest. The avoidance of an actual or perceived conflict of interest and/or bias is central to the effectiveness of the DRB. Consequently, the DRB Members shall meet the following criteria and limitations for membership:

**Exhibit U - Dispute Resolution Procedures**

2.4.1 Direct Employment: Individuals who are current or former employees of any of the Parties, or any of the Additional Project Parties that are currently engaged as to any aspect of the Vogtle Units 3&4 project, may not serve as DRB Members. Prospective DRB Members who are current or former employees of any of the Potential Conflict Parties must disclose that employment information in writing.

2.4.2 Attorney-Client Relationships: Attorneys who have been involved in the representation of any of the Parties, or Additional Project Parties in relation to the Vogtle Units 3&4 project, may not serve as DRB Members. Any past or present involvement in the representation of any of the Parties or Potential Conflict Parties must be disclosed in writing, along with any past or present representation of any of the Potential Conflict Parties by the prospective DRB Member's law firm.

2.4.3 Close Personal or Professional Relationships: Individuals with a close personal or professional relationship with a key individual of any of the Parties may not serve as DRB Members. All relationships with any individuals listed as Potential Conflict Parties or otherwise known to be associated with any of the Potential Conflicts Parties must be disclosed in writing.

2.4.4 Service on Other Mediation/Arbitration: All past and current service as a mediator or as an arbitrator on projects involving any of the Parties or Additional Project Parties must be disclosed in writing.

2.4.5 Prior Involvement: No DRB Member shall have had substantial prior involvement in the Vogtle Units 3&4 project, as determined by the Owners and the Contractor, except that prior service on a DRB relating to the Vogtle Units 3&4 project is not objectionable.

2.4.6 Financial Interest: No Member shall have any Financial Interest in any Party or any Financial Interest in the Construction Completion Agreement except for payment of its fees and expenses as provided herein or in the DRB Member Agreement. Prospective DRB Members with a Financial Interest in any of the Potential Conflict Parties, or a prior Financial Interest in any of the Project Parties or Additional Project Parties, must disclose those Financial Interests in writing.

2.4.7 Consultant: No DRB Member shall have been, nor for the duration of the DRB be, employed as a consultant or otherwise by any Party or its Personnel or, including as a representative for purposes of negotiations, unless any such relationship has been disclosed in writing to and approved by all Parties.

2.4.8 Advice: No DRB Member shall give advice to any Party or its Personnel concerning the conduct of the Construction Completion Agreement, other than in accordance with these DRB Procedures.

2.4.9 Ex-parte Communication: No DRB Member shall have any ex-parte communications with any Party at any time after their becoming a DRB Member, except as permitted otherwise by these DRB Procedures.

**Exhibit U - Dispute Resolution Procedures**

2.4.10 Confidentiality: Each DRB Member shall treat the details of the Construction Completion Agreement, all matters discussed with the DRB, and all the DRB's activities and DRB Hearings as private and confidential, and shall not publish, comment on or disclose them without the prior written consent of the Parties.

2.5. While serving as a DRB Member, no DRB Member shall participate in any discussion contemplating the creation of an agreement or making an agreement with any of the Parties, their Personnel or any current Additional Project Party regarding present or future employment or fee-based consulting services, or any other business arrangement after ceasing to act as a DRB Member or after the Construction Completion Agreement is completed.

2.6. Except for their respective participation in any DRB proceeding, none of the Parties shall solicit advice or consultation from the DRB Members, and the DRB Members shall refrain from offering or providing such advice or consultation.

Article 3. ESTABLISHMENT OF THE DRB

3.1. The Owners and the Contractor shall meet to exchange lists of the Additional Project Parties, Other Parties, and their key personnel.

3.2. The Owners and the Contractor shall discuss and establish the qualifications upon which prospective DRB Members are to be evaluated and to jointly agree on three or more prospective DRB Members. Upon agreement on a list of prospective DRB Members, such prospective DRB Members will be jointly contacted by the Parties, provided with a copy of these DRB Procedures including Attachment 1 hereto, and the list of Potential Conflict Parties, and invited to submit the following information for further consideration by the Owners and Contractor:

3.2.1 Resume showing experience and qualifications as required by these DRB Procedures.

3.2.2 Identification of past and current experience as a member of an arbitral or mediation panel. Each such assignment shall be listed separately, indicating the name and location of the project, dates of service, name of owner, name of contractor, contract value, name of nominating party, if applicable, and names of the other members.

3.2.3 Disclosure statement describing past, present, and anticipated relationships, including indirect relationships through the prospective DRB Member's employer, if any, respecting all Potential Conflict Parties and otherwise in accordance with the requirements of Article 2 above.

3.3. Disclosure is a continuing obligation of all DRB Members throughout the life of the DRB.

3.4. The Owners and the Contractor shall meet again within fifteen (15) Days of the receipt of this information to review and mutually agree on the final selection of all three DRB Members. In the event that all three DRB Members were not selected from the initial pool of candidates, the process shall be repeated as necessary.

**Exhibit U - Dispute Resolution Procedures**

3.5. Within fifteen (15) Days of completion of the selection process, the DRB Member Agreement shall be executed among the three DRB Members, the Owners, and the Contractor. The DRB Member Agreement sets forth the terms and conditions that apply to the services to be provided by the DRB Members and, if the composition of the DRB changes, shall be amended to reflect such changes. The DRB shall be deemed constituted when the DRB Member Agreement is fully executed by all signatories.

3.6. The three DRB Members shall designate the DRB chair and, in writing, notify the Owners and the Contractor of the identity of the DRB chair.

3.7. In the event any DRB Member resigns, becomes incapacitated, dies or is otherwise incapable of serving as a member of the DRB, then a replacement member shall be selected in accordance with this Section 3.7. In the event of a vacancy on the DRB, the Parties shall engage in good faith discussions to agree on a replacement DRB Member and fill the vacancy as quickly as practicable. If the vacancy has existed for thirty (30) Days and the Parties have not agreed on a replacement, the Contractor shall offer the names of two prospective replacement DRB Members and the Owners shall collectively offer two names. The information described in Section 3.2 shall be assembled for the four candidates. The four names, along with the assembled information, shall be provided to the remaining members of the DRB in alphabetical order, without any information identifying which candidates were suggested by each Party. The remaining DRB Members shall select a replacement DRB Member from the four names on the list. If two vacancies exist at the same time, the same process shall be used except the one remaining DRB Member shall select two replacement DRB Members from the four names on the list in the event the Parties are unable to fill the vacancies.

Article 4. TERMS AND TERMINATION OF THE DRB

4.1. Each DRB Member shall be appointed for the life of the Construction Completion Agreement but not beyond the dissolution of the DRB as provided in Section 4.4 below. The services of a DRB Member may be terminated without cause only by mutual agreement of the Parties. In such event, written notice of the termination, signed by the Parties, will be provided to the DRB Members, and the termination will be effective upon the date the notice is signed by the Parties. The Parties will thereafter fill the vacancy in accordance with the terms of these DRB Procedures.

4.2. The services of a DRB Member may be terminated for cause only as follows:

4.2.1 Any Party may seek removal of a DRB Member for demonstrated bias, partiality or lack of independence, inability or refusal to perform his or her duties with diligence and in good faith or other improper conduct or any other grounds for disqualification provided by applicable law.

4.2.2 If a Party becomes aware of a conflict of interest for a DRB Member, it may, by written notice copied to the other Parties and all DRB Members, request that the DRB Member with such alleged conflict explain, remedy or remove the alleged conflict. If the alleged conflict is not remedied or removed within twenty-one (21) Days of notice, then the Party may seek to terminate the DRB Member.

**Exhibit U - Dispute Resolution Procedures**

4.3. Any Party seeking to terminate a DRB Member for cause shall first confer with the other Party to determine if the other Party agrees with the termination. If there is failure to reach agreement, the Party seeking termination shall have the right to proceed to a court of competent jurisdiction as identified in the DRB Member Agreement to effect the termination.

4.4. The DRB shall be dissolved upon completion of its deliberations and delivery of a DRB Determination on any Contract Claims pending at Final Completion of Unit 4; except that if the Construction Completion Agreement is terminated, the DRB shall immediately be dissolved, except to the extent, and for the purpose of resolving, any unresolved Contract Claims previously submitted to the DRB. After the DRB is dissolved as provided herein, it shall have no further authority to consider Contract Claims.

4.5. DRB Members' Compensation

DRB Members shall be compensated in accordance with the DRB Member Agreement.

Article 5. DRB MEETINGS

5.1. The DRB will visit the Site and meet with representatives of the Parties at periodic intervals and at additional times so requested by the Parties. The DRB Chair shall schedule the regular meetings on a quarterly basis unless the Owner, Contractor and DRB agree that more frequent or less frequent meetings are appropriate given the scope, duration and current status of the Vogtle Units 3&4 project. Under no circumstances, however, shall the frequency of regular DRB meetings be less than two times per year.

5.2. As requested by the DRB, the Contractor shall provide the DRB and Owners with a current list of pending or unresolved change orders and claimed and open adjustments to the Target Completion Dates or Target Construction Cost, as well any other information, schedule, or status reports, in advance of each DRB Meeting.

5.3. Each meeting shall consist of an informal discussion and a field observation of the Work in progress. The DRB may issue verbal, non-binding advisory opinions as to current items discussed at the meeting pursuant to Article 9 below. The discussion and field observation shall be attended by personnel of the Owners and Contractor. Individual discussion or consultation with DRB Members without both Parties present is strictly prohibited

Article 6. DRB DISPUTE PROCEEDINGS - GENERAL

6.1. DRB Rules of Operation

The DRB shall formulate its own rules of operation, consistent with these procedures. The DRB need not adopt hard and fast rules for every aspect of its operation; the procedures may be kept flexible to adapt to the needs of particular situations. The DRB rules of operations shall be subject to the approval of the Parties prior to implementation, and modifications of such rules shall similarly be subject to approval by the Parties. The DRB Chair may make procedural decisions, and provide direction on other issues as provided by Article 38 or these procedures.

**Exhibit U - Dispute Resolution Procedures**

6.2. DRB Determinations

DRB Determinations shall be consistent with the Construction Completion Agreement and appropriate legal precedents. The DRB shall not supplant or otherwise interfere with the respective rights, authorities, duties, and obligations of the Owners and the Contractor as defined in the Construction Completion Agreement. In rendering DRB Determinations and providing advisory opinions, the DRB shall acknowledge the centrality of the Construction Completion Agreement and shall not make a DRB Determination or provide an advisory opinion that ignores, disregards, or undermines the intention, requirements, economic allocation of risk, or Work specified in the Construction Completion Agreement.

6.3. Date, Time and Place of DRB Hearings

The DRB shall set the date, time, and place for each DRB Hearing, provided that Hearings shall take place at the Site or in Atlanta, GA, unless otherwise agreed by the Parties.

6.4. Contract Claim and Defense Statements

All summaries of Contract Claims, defenses and arguments shall include, at minimum, a statement of the Party's position with regard to both entitlement and amount of the Contract Claim and an explanation of the basis and justification for such position with reference to relevant Construction Completion Agreement language and the supporting documentation for each element of the Contract Claim.

6.5. Production of Information

(a) *Authority of DRB* . The DRB shall have access to all such information from any Party as it deems necessary to carry out its function. A Party that is requested by the DRB to provide information and/or documents relating to the subject matter of any Contract Claim submitted to the DRB shall promptly provide such information and/or documents to the DRB, with a copy to the other Party. The DRB shall manage any necessary exchange of information among the Parties with a view to achieving an efficient and economical resolution of the Contract Claim. The DRB may request production of additional information and/or documents from any Party at any time.

(b) A Party intending to offer an outside expert's analysis at a DRB Hearing shall disclose such intention in writing to the other Party and to the DRB within the time period established by the DRB at the initial conference. The expert's name and a statement of the specific aspect of the Contract Claim that will be covered by his or her testimony shall be included in the disclosure. Upon receipt of the above disclosure, the other Party shall have the opportunity to identify an outside expert to address or respond to those issues, who shall be similarly disclosed.

6.6. General Powers of the DRB

The DRB shall have the authority to issue any additional directions needed to achieve a fair, efficient and economical DRB Determination of the Contract Claim.

**Exhibit U - Dispute Resolution Procedures**

6.7. Attendance at DRB Hearings

(a) The Parties shall limit attendance at the Hearing to individuals directly involved in the dispute or having management responsibilities with respect to the dispute or its resolution. Prior to the Hearing, each Party shall submit a list of its proposed attendees to the DRB and the other Party. Any disagreements as to proposed attendees shall be resolved by the DRB. As a matter of right, attorneys for each Party may attend as observers but not participate in the Hearing, except as provided in these procedures.

(b) Subcontractor personnel may attend Hearings involving pass-through Contract Claims by such Subcontractor, or where reasonably required due to their involvement in relevant events. The Contractor shall require that each Subcontractor involved in a dispute have present an authorized representative and personnel with actual knowledge of the underlying events.

(c) The DRB shall maintain the privacy of DRB proceedings. The DRB shall have the power to require the exclusion of any witness, other than a Party representative or other essential person, during the testimony of any other witness. It shall be discretionary with the DRB to determine the propriety of the attendance of any person other than a Party and its representative.

6.8. Transcription

No transcript of a DRB Hearing is generally contemplated. Each DRB Member may keep his/her own notes. In special cases, upon request of a Party, the DRB may allow transcription by a court reporter at the expense of the requesting Party, who shall provide copies of the transcript to the DRB and the other Party at no charge. Audio or video recordings are not permitted.

6.9. Postponements of DRB Hearings

The DRB for good cause shown may postpone any DRB Hearing or interim deadline upon agreement of the Parties, upon request of a Party, or upon the DRB's own initiative.

6.10. Conduct of Hearings

(a) Each Party to a DRB Proceeding shall have the right to present witnesses and documents as reasonably necessary to achieve full and true disclosure of the facts. The DRB has the discretion to vary the Hearing procedure, provided that the Parties are treated with equality and that each Party has the right to be heard and is given a fair opportunity to present its position on the Contract Claim, through successive rebuttals as reasonably needed until, in the DRB's opinion, all aspects of the dispute have been fully and fairly covered.

(b) The DRB, exercising its discretion, shall conduct the proceedings with a view toward expediting the resolution of the Contract Claim and may direct the order of proceeding, bifurcate proceedings, and direct the Parties to focus their presentations on issues most significant to determination of all or substantial part of the Contract Claim.

**Exhibit U - Dispute Resolution Procedures**

Either Party may request that the DRB direct a question to or clarification from the other Party, which will be granted at the discretion of the DRB. In general, the DRB will not allow one Party to be questioned directly by the other Party at Hearings conducted without attorney representation.

(c) In addressing each Contract Claim, the DRB shall (i) be neutral and act fairly and impartially as between Owners and Contractor, (ii) give each Party a reasonable opportunity to present its position regarding the Contract Claim, through witnesses, documents and arguments to support its position, and to respond to the other Party's position, (iii) adopt procedures suitable to such Contract Claim, and (iv) follow the Construction Completion Agreement and applicable Law.

(d) The DRB shall not accept evidence that is covered by the attorney-client privilege or that constitutes attorney work product. The rules of evidence in a court proceeding otherwise do not apply.

(e) In the event that any Party fails to comply with the pre-Hearing deadlines established by the DRB, the DRB shall, in its discretion, determine whether the DRB Hearing shall proceed as originally scheduled, or whether additional time shall be provided and a new date established. On the final date and time established for the DRB Hearing, the DRB shall proceed with the DRB Hearing and rendering its DRB Determination, utilizing the information that has been submitted, including if a Party fails to appear.

6.11. Site Inspections

If the DRB finds it necessary or useful to make a site inspection in connection with a DRB proceeding, the DRB shall, subject to the agreement of the Parties, set the date and time for such inspection. Absent agreement of the Parties, the DRB shall not undertake a site inspection unless both Parties are present.

6.12. Interim Measures

(a) The DRB may direct whatever interim measures it deems necessary, including ordering injunctive relief and measures for the protection or conservation of property.

(b) A request for interim measures addressed by a Party to a judicial authority shall not be deemed incompatible with the agreement for a DRB Proceeding or a waiver of the right to a DRB Proceeding.

6.13. Closing of DRB Hearing

(a) If further documents or responses are to be provided following the Hearing, the DRB Hearing shall be closed as of the final due date set by the DRB for the receipt of such documents or responses. Otherwise, the DRB Hearing will be closed as of the conclusion of the DRB Hearing.

**Exhibit U - Dispute Resolution Procedures**

(b) The time within which the DRB is required to make the DRB Determination commences upon the closing of the DRB Hearing. The DRB may extend the time limit for the rendering of the DRB Determination only in unusual and extreme circumstances.

6.14. Expenses

All DRB expenses incurred in relation to a DRB proceeding, including required travel and other expenses of the DRB Members, shall be borne equally by the Parties.

6.15. Submissions to DRB

Unless otherwise instructed by the DRB, any documents submitted by any Party to the DRB shall simultaneously be provided to the other Party.

6.16. Scope of DRB Determination

(a) The DRB may grant any remedy or relief that the DRB deems just and equitable and within the scope of the agreement of the Parties, including, but not limited to, monetary and/or equitable relief.

(b) In addition to the final DRB Determination, the DRB may make other decisions, including interim, interlocutory, or partial rulings, orders, and partial DRB Determinations, as reasonably required.

(c) The DRB Determination may include interest as provided in the Construction Completion Agreement from such date as the DRB may deem appropriate; and

(d) The effectiveness and finality of a DRB Determination shall be as provided in Article 38 of the Construction Completion Agreement.

6.17. Form of DRB Determination

A DRB Determination shall be in writing, include an explanation of the reasoning for the decisions reached, and be signed by at least a majority of the DRB Members. However, the DRB shall make every effort to reach unanimous DRB Determination. The DRB Determination shall provide a breakdown of any monetary components included in the DRB Determination, and a line item disposition of any non-monetary Contract Claim items.

6.18. Acceptance of DRB Determination

Within twenty-one (21) Days of receipt of the DRB Determination (unless extended by a request for clarification or reconsideration), each Party shall determine whether or not it will accept or reject the DRB Determination. If the Parties are able to resolve the dispute with the aid of the DRB Determination, their agreement shall be promptly reflected in an executed Change Order.

**Exhibit U - Dispute Resolution Procedures**

6.19. Court or Arbitration Proceedings

Neither the DRB nor any DRB Member is a necessary or proper party in any judicial or arbitration proceedings relating to a DRB Proceeding or DRB Determination.

Article 7. REGULAR HEARING PROCEDURE

7.1. Applicability of Regular Hearing Procedure

Unless the Parties agree, or if unable to agree, the DRB determines that the Construction Completion Agreement specifies use of the Expedited Hearing procedure, the Regular Hearing procedure shall apply to Contract Claims to be heard by the DRB.

7.2. Initial Statements of Contract Claim and Defense

(a) Within ten (10) Days after a Contract Claim is submitted to the DRB pursuant to the Regular procedure (or it is determined that the Regular procedure applies to the Contract Claim), the claiming Party shall provide the DRB and the other Party a summary of its Contract Claim including a statement of the amounts in dispute.

(b) Within twenty (20) Days after receipt of such statement, the Party against whom the Contract Claim is asserted shall submit a summary of its defenses and arguments with respect to the Contract Claim and its position with respect to the amounts in dispute, along with any counterclaim respecting the subject of the Contract Claim.

7.3. Initial Telephone Conference

Within fifteen (15) Days of submission of the responsive summary, the DRB will convene a preliminary conference via conference call to establish the Hearing date(s), location and all appropriate pre-Hearing deadlines. If requested by the DRB, the Parties shall provide more detailed statements of their respective positions at a date in advance of the pre-Hearing submission.

7.4. Pre-Hearing Submission

(a) The Owners and the Contractor shall each prepare a preHearing submission and transmit it to the DRB at least thirty (30) Days before the date of the DRB Hearing. The pre-Hearing submission, comprising a position paper with such backup data as is referenced in the position paper, shall be tabbed, indexed, and the pages consecutively numbered. When the scope of the DRB Hearing includes Target Completion Date extension requests by the Contractor, each Party’s submission shall include a CPM delay analysis utilizing the appropriate update of the Project Schedule, and considering potential concurrent causes of delay. When the scope of the DRB Hearing includes Target Construction Cost increases or decreases, the claiming Party shall provide full actual cost details.

(b) Any expert reports shall be included in the pre-Hearing submissions.

**Exhibit U - Dispute Resolution Procedures**

7.5. At least fifteen (15) Days before the date of the Hearing, the Parties shall exchange copies of all exhibits, affidavits and any other information they intend to submit at the DRB Hearing not included in the pre-Hearing submissions, and identify all witnesses they intend to present at the DRB Hearing.

7.6. Use of Legal Counsel

While it is generally contemplated that attorneys for the Parties will not participate in the Hearing (but may attend the Hearing as observers), in particularly large or complex disputes the DRB is authorized, upon request of a Party or in its own discretion, to permit legal counsel representation of the Parties at the Hearing. Any such requests must be raised in advance of the initial conference. Where permitted, both Parties must be so represented, and the DRB may vary its otherwise applicable rules of procedure to reflect such representation, such as by permitting reasonable cross-examination of witnesses and opening statements or closing arguments. In no event shall the rules of evidence applicable in a court proceeding be applied.

7.7. Additional Hearings

In difficult or complex Contract Claims, additional DRB Hearings may be necessary to facilitate full consideration and understanding of the Contract Claim. In the discretion of the DRB such additional Hearing time may be allowed as determined by the DRB.

7.8. Time for DRB Determination

The Regular Hearing is intended to be an expedited process designed to achieve disposition of Contract Claims within four (4) to six (6) months of instituting the process. The DRB Determination shall be made promptly by the DRB and, unless otherwise agreed by the Parties, no later than thirty (30) Days from closing the Hearing.

7.9. Clarification and Reconsideration

(a) Either Party may request clarification of a DRB Determination within ten (10) Days following its receipt. As expeditiously as practicable, the DRB shall provide written clarification to both Parties. Only one request for clarification per Contract Claim from each Party will be allowed.

(b) Either Party may request reconsideration of a DRB Determination within ten (10) Days following its receipt, but such requests shall be based upon new information obtained or developed after the Hearing, or when in the Party's opinion the DRB misunderstood or failed to consider critical facts respecting the Contract Claim. The DRB will not entertain requests that amount to a renewal of prior arguments or additional arguments based on facts available at the time of the Hearing, and only one request for reconsideration per Contract Claim from each Party will be allowed.

**Exhibit U - Dispute Resolution Procedures**

Article 8. EXPEDITED HEARING PROCEDURE

8.1. Applicability

The Expedited Hearing Procedure applies when so provided in the Construction Completion Agreement, or otherwise agreed by the Parties.

8.2. Initial Statements of Contract Claim and Defense

(a) At the time of submission or within (5) Days after a Contract Claim is submitted to the DRB pursuant to the Expedited procedure (or it is determined that the Expedited procedure applies to the Contract Claim), the claiming Party shall provide the DRB and the other Party a summary of its Contract Claim including a statement of the amounts in dispute.

(b) Within ten (10) Days after receipt of such statement, the Party against whom the Contract Claim is asserted shall submit a summary of its defenses and arguments with respect to the Contract Claim and its position with respect to the amounts in dispute, along with any counterclaim respecting the subject of the Contract Claim.

8.3. Initial Telephone Conference

Within five (5) Days of submission of the responsive summary, the DRB will convene a preliminary conference via conference call to establish the Hearing date(s), location and all appropriate pre-Hearing deadlines.

8.4. Pre-Hearing Submission

(a) The Owners and the Contractor shall each prepare a preHearing submission and transmit it to the DRB at least fifteen (15) Days before the date of the DRB Hearing. The pre-Hearing submission, comprising a position paper with such backup data as is referenced in the position paper, shall be tabbed, indexed, and the pages consecutively numbered. When the scope of the DRB Hearing includes Target Completion Date extension requests by the Contractor, each Party’s submission shall include a CPM delay analysis utilizing the appropriate update of the Project Schedule, and considering potential concurrent causes of delay. When the scope of the DRB Hearing includes Target Construction Cost increases or decreases, the claiming Party shall provide full actual cost details.

(b) Any expert reports shall be included in the pre-Hearing submissions.

8.5. At least ten (10) Days before the date of the Hearing, the Parties shall exchange copies of all exhibits, affidavits and any other information they intend to submit at the DRB Hearing not included in the pre-Hearing submissions, and identify all witnesses they intend to present at the DRB Hearing.

8.6. Use of Legal Counsel

Attorney representation may not be used for Expedited Hearings.

8.7. Time for DRB Determination

The Expedited Hearing is intended to be a more expedited process designed to achieve disposition of Contract Claims within no more than sixty (60) Days after the date a Contract Claim is submitted to the DRB, and more rapidly when practicable. It is normally to be expected that the Hearing shall be closed no later than forty-six (46) Days after the date the Contract Claim is submitted to the DRB, unless all Parties and the DRB agree otherwise, or the DRB extends this time in extraordinary cases when the demands of justice require it. The DRB Determination shall be made promptly by the DRB and, unless otherwise agreed by the Parties, no later than fourteen (14) Days from closing the Hearing.

8.8. Clarification

Either Party may request clarification of a DRB Determination within five (5) Days following its receipt. As expeditiously as practicable, the DRB shall provide written clarification to both Parties. Only one request for clarification per Contract Claim from each Party will be allowed. No request for reconsideration will be entertained by the DRB in the Expedited Hearing process absent the most compelling circumstances.

Article 9. ADVISORY OPINIONS

9.1. An advisory opinion serves as a method for potentially avoiding a DRB Hearing. It is not intended to replace the Hearing processes described herein, but may be implemented as part of the good-faith negotiation conducted between the Parties. An advisory opinion is not a DRB Determination.

9.2. When mutually agreed by the Owners and the Contractor, the DRB may provide an advisory opinion on any issue, whether or not the subject of a Contract Claim. Advisory opinions are generally rendered in connection with regular DRB meetings, but may be the subject of a special meeting if so agreed by the Parties.

9.3. A written submittal from each Party respecting the issue submitted for an advisory opinion shall normally be required, subject to any limitations established by the DRB, that defines the issue(s) to be considered and sets out the submitting Party's position and supporting rationale. The Parties shall submit and exchange their submittals by e-mail a minimum of five Days prior to the meeting at which the Parties desire to obtain the advisory opinion.

9.4. The Parties may make such oral presentations of their positions as the DRB determines appropriate to the issue, followed by discussion and DRB questions as needed to help ensure that the advisory opinion is suitable and appropriate for the issue presented.

9.5. The DRB Members will caucus privately prior to presenting their oral advisory opinion. Opinions will not be reduced to writing unless agreed by the Parties and the DRB.

**Exhibit U - Dispute Resolution Procedures**

9.6. The DRB in its discretion may decline to provide an advisory opinion when deemed inappropriate, in its discretion.

## Exhibit V – Legacy, WIP, and Completed Work Packages

Table 1 lists 425 Legacy Work Packages where the field work and inspections have been completed, but the Work Package has not been closed as of October 17, 2017.

Table 2 lists 1,147 Completed and Voided Work Packages which are complete and closed as of October 17, 2017.

Table 3 lists 4,614 In-Progress Work Packages which have been partially implemented as of October 17, 2017.

# Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 1. Legacy Work Packages (as of October 17, 2017) | | |
|---|---|---|
| **No.** | **Work Package Number** | **Title** |
| 1 | SV3-RNS-P0W-ME0538 | FABRICATION/INSTALLATION OF PIPING FOR ISO SV3-RNS-PLW-210 |
| 2 | SV3-VWS-PHW-ME0810 | INSTALLATION OF SMALL BORE VWS PIPING SUPPORTS FROM ISOMETRICS SV3-VWS-PLW-241, AND SV3-VWS-PLW-250 (INCLUDES SUPPORTS SV3-VWS-PH -12R24031, -12R24041, -12R26621, AND 12R9102) |
| 3 | SV3-VWS-PHW-ME0813 | INSTALLATION OF SMALL BORE VWS PIPING SUPPORTS FROM ISOMETRIC SV3-VWS-PLW-680 AND ISOMETRIC SV3-VWS-PLW-690 (INCLUDES SUPPORTS SV3-VWS-PH-12R2389, -12R2398, -12R2770) |
| 4 | SV3-VWS-PHW-ME0812 | INSTALLATION OF SMALL BORE PIPING SUPPORTS FROM ISOMETRIC SV3-VWS-PLW-390, AND SV3-VWS-PLW-490. (INCLUDES SUPPORTS VWS-PH-12R2386, VWS-PH-12R2400, VWS-PH-12R2401, & VWS-PH-12R9104) |
| 5 | SV3-VWS-PHW-ME0811 | INSTALLATION OF SMALL BORE PIPING SUPPORTS FROM ISOMETRIC SV3-VWS-PLW-280, AND SV3-VWS-PLW-290. (INCLUDES SUPPORTS VWS-PH-12R2392, VWS-PH-12R2395, VWS-PH-12R2664, & VWS-PH-12R9103) |
| 6 | SV3-SFS-P0W-ME0921 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC SV3-SFS-PLW-860 (LINE NUMBERS SFS-PL-L033 & L044) |
| 7 | SV3-WLS-PHW-ME0839 | FABRICATION/INSTALLATION OF SMALL BORE WLS PIPING SUPPORTS FOR ISOMETRIC DRAWING SV3-WLS-PLW-931 |
| 8 | SV3-CA20-S4W-CV4788 | FABRICATION OF REPLACEMENT CA20 OVERLAY PLATES |
| 9 | SV4-CB65-S4W-CV2571 | TEMPORARY ATTACHMENTS FOR CB65 |
| 10 | SV0-DRS-XDW-CV0012 | PERFORM EXCAVATION AND BACKFILL AND INSTALL BURIED DRS PIPE AND PRECAST DRAINAGE STRUCTURES |
| 11 | SV3-4042-CRW-CV3181 | U3 ANNEX AREA 2 CONCRETE REINFORCEMENT ELEVATION 100'-0" TO ELEVATION 117'-6" |
| 12 | SV3-2020-MEW-ME0849 | UNIT 3 CONDENSER B CONNECTION PIECE ASSEMBLY |
| 13 | SV3-2020-MEW-ME0556 | Unit 3 Condenser B Hot Well Assembly |
| 14 | SV3-2020-MEW-ME0557 | Unit 3 Condenser C Hot Well Assembly |
| 15 | SV3-2020-MEW-ME0737 | Install Condenser C Upper Tube Bundle |
| 16 | SV3-2020-MEW-ME0734 | Assemble Condenser C Lower Tube Bundle |
| 17 | SV3-2020-MEW-ME0850 | Install Condenser C Upper Shell Exterior Shell |
| 18 | SV3-2020-MEW-ME0733 | Install Condenser B Lower Tube Bundle |
| 19 | SV3-2020-MEW-ME0735 | Assemble Condenser A Upper Tube Bundle |
| 20 | SV3-2020-MEW-ME0846 | Install Condenser B Upper Shell Exterior Shell |
| 21 | SV3-1120-CEW-CV1593 | INSTALLATION OF EMBEDS AND ANCHOR BOLTS FOR CONTAINMENT ELEVATION 71'-6" TO 84'-6" |
| 22 | SV3-CA05-S4W-CV5324 | UNIT 3 CA05 OVERLAY PLATE REMOVAL AND REINSTALLATION |
| 23 | SV4-CWS-EQW-EL0118 | Electrical Contuinity Installation for CWS (Phases 1 & 2) |
| 24 | SV3-1120-CRW-CV1592 | Containment Concrete Reinforcement El. 71ft-6in to 84ft-6in |

# Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 1. Legacy Work Packages (as of October 17, 2017) | | |
|---|---|---|
| **No.** | **Work Package Number** | **Title** |
| 25 | SV4-2020-CCW-CV0382 | UNIT 4 TURBINE BUILDING, CONCRETE PEDESTALS, CURBS AND EQUIPMENT PADS AT 82 FT - 9 IN ELEVATION |
| 26 | SV3-CA01-S4W-CV2755 | CA01-18 UNSAT IR AND N&D REPAIRS |
| 27 | SV3-CA01-S5W-CV2498 | CA01-20 & CA01-21 INSPECTION REPORT (IR) & N&D REPAIRS |
| 28 | SV3-CA01-S5W-CV2666 | CA01-25 UNSAT IR AND N&D REPAIRS |
| 29 | SV3-CA01-S5W-CV3110 | CA01-19 PERFORM N&D & INSPECTION REPORT (IR) S561-004-14-0383 REWORK AND REPAIRS. |
| 30 | SV3-CA01-S5W-CV3270 | CA01-31 INTERNAL FABRICATION |
| 31 | SV3-CA01-S5W-CV3316 | CA01-04 STRUCTURE UNSAT IR'S AND N&D'S REWORK AND REPAIRS |
| 32 | SV3-CA01-S5W-CV3320 | CA01-05 UNSATISFACTORY IRS AND N&D REPAIRS - STUDS |
| 33 | SV3-CA01-S5W-CV4212 | CA01-15 UNSATISFACTORY IRS AND N&D REPAIRS - STUDS |
| 34 | SV3-CA01-S5W-CV4218 | CA01-33 UNSATISFACTORY IRS AND N&DS - STUDS |
| 35 | SV3-CA01-S5W-CV4223 | CA01-36 UNSAT STRUCT IR AND N&D'S |
| 36 | SV3-CA05-S4W-CV2341 | FABRICATE CA05 CONNECTION AND EMBEDMENT PLATES |
| 37 | SV3-CA20-S4W-CV1674 | CA20 SA4 LEAK CHASE ASSEMBLY |
| 38 | SV3-CA20-V2W-CV1730 | INSTALL CA20 LIFT LUGS 168 AND 169 |
| 39 | SV0-PWS-PLW-ME0042 | Fabrication and Installation of Trench 4 HDPE Potable Water System |
| 40 | SV3-R151-R1W-ME3666 | COMPLETION OF STRUCTURAL MODULE R151 |
| 41 | SV3-WLS-P0W-ME2133 | Installation of Small Bore KB12 WLS Piping (Includes Isometrics SV3-WLS-PLW-60C, 60N & 686 |
| 42 | SV4-CA20-S4W-CV6949 | INSTALLATION OF CA20-64 & 65 |
| 43 | SV4-G100-XEW-CV0543 | Unit 4 Horizontal Waterproofing Membrane |
| 44 | SV3-CA05-S4W-CV1867 | CA05 WALL ASSEMBLY |
| 45 | SV3-2020-MEW-ME0851 | Install Condenser C Upper Shell Heat Truss |
| 46 | SV3-CA02-S5W-CV5933 | CA02-01 UNSATIFACTORY IR, N&D REPAIRS - STUDS |
| 47 | SV3-CA03-S4W-CV2253 | CA03 SUBMODULE WALL ASSEMBLY (07, 08, 09, 10, 11) |
| 48 | SV4-WGS-P0W-ME6623 | INSTALLATION OF SMALL BORE WGS PIPING (INCLUDES SV4-WGS-PLW-051, 061, 071, 081, 091) |
| 49 | SV4-1208-SCW-CV6997 | Course 4 Unit 3 Shield Building |
| 50 | SV3-CA01-S4W-CV2063 | CA01-35 OVERHANG INSTALLATION |
| 51 | SV3-CA01-S4W-CV2229 | INSTALLATION OF CA01-13 |
| 52 | SV3-CA01-S4W-CV2237 | CA01-27 SUBMODULE ERECTION |
| 53 | SV3-CA01-S4W-CV2242 | CA01-34 SUBMODULE ERECTION |
| 54 | SV3-CA01-S4W-CV2554 | CA01-16 FABRICATION & ASSEMBLY |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 1. Legacy Work Packages (as of October 17, 2017) | | |
|---|---|---|
| No. | Work Package Number | Title |
| 55 | SV3-CA01-S4W-CV2556 | CA01-18 SUBMODULE ERECTION |
| 56 | SV3-CA01-S4W-CV2557 | CA01 SM 19 INSTALLATION |
| 57 | SV3-CA01-S4W-CV4217 | CA01 -21 SUPPOT LEG INSTALLATION (SA5) |
| 58 | SV3-CA01-S5W-CV2083 | CA01-32 FINISH PRE-FABRICATION, |
| 59 | SV3-CA01-S5W-CV2326 | CA01-07 REPAIRS |
| 60 | SV3-CA01-S5W-CV2707 | CA01-17 UNSAT IR AND N&D REPAIR |
| 61 | SV3-CA01-S5W-CV2844 | CA01-29 JOINING OF SECTION 100 AND 200 |
| 62 | SV3-CA01-S5W-CV3133 | CA01-39 UNSAT IRS AND N&DS - STRUCTURE REPAIRS |
| 63 | SV3-CA01-S5W-CV3325 | CA01-13 PERFORM N&D & INSPECTION REPORT (IR) S561-004-14-0451 REWORK AND REPAIRS |
| 64 | SV3-CA20-S4W-CV0428 | CA20 SA2 EL. 82FT-6IN FLOOR INSTALLATION |
| 65 | SV3-CA20-S4W-CV0437 | CA20 SA4 Wall Submodule Assembly (Includes CA20- 26, 27, 28, 29, 30, 71, 72, 73) |
| 66 | SV3-CA20-S4W-CV1406 | CA20 SA3 WALL SUBMODULE ASSEMBLY (18, 19, 20, 21, 22, 23, 24, 25 ) |
| 67 | SV3-CA20-S5W-CV1422 | CA20-05 LINER PLATE WELD MODIFICATION |
| 68 | SV3-CA20-S5W-CV1673 | CA20 SA3 MISCELLANEOUS REWORK FOR CLOSURE OF ND'S. |
| 69 | SV3-CA20-V2W-CV1727 | INSTALL CA20 LIFT LUGS 162 AND 163 |
| 70 | SV3-2020-MEW-ME1598 | Unit 3 Condenser A Flashbox Installation |
| 71 | SV3-1220-CPW-CV0950 | Unit 3 Auxilary Building Precast Concrete Floors El.82'-6" |
| 72 | SV3-2020-MEW-ME1599 | UNIT 3 CONDENSER C FLASHBOX INSTALLATION |
| 73 | SV3-KB27-KBW-ME2204 | Installation of KB27 Components |
| 74 | SV4-CA20-S5W-CV5600 | CA20-20 UNSAT IR - STUDS (LOOSE PARTS), |
| 75 | SV4-CA20-S4W-CV5608 | INSTALLATION OF SUBMODULE CA20-21 |
| 76 | SV3-CA01-S5W-CV3315 | CA01-04 PERFORM N&D & INSPECTION REPORT (IR) S540-004-14-0043 REWORK AND REPAIRS. |
| 77 | SV3-CA01-MHW-CV2162 | LIFTING FRAMES AND BRACING SUBMODULES 05 THRU 10 |
| 78 | SV4-CA05-S5W-CV6049 | CA05-08 UNSAT IRS & N&DS - STRUCTURAL, |
| 79 | SV3-CA01-S5W-CV5780 | SUBASSEMBLY 7 BASEMAT FABRICATION |
| 80 | SV4-CA05-S5W-CV6044 | CA05-07 UNSATISFACTORY IRs AND N&D REPAIRS - STUDS |
| 81 | SV4-CA20-S4W-CV5748 | INSTALLATION OF SUB MODULE CA20-28 |
| 82 | SV4-CA05-S4W-CV6030 | CA05-04 SUBMODULE INSTALLATION |
| 83 | SV4-CA05-S4W-CV6034 | CA05-05 SUBMODULE INSTALLATION |
| 84 | SV4-CA05-S4W-CV6018 | CA05-01 Upending/Submodule Installation |
| 85 | SV4-CA20-S4W-CV5753 | INSTALLATION OF SUB MODULE CA20-29 |
| 86 | SV4-CA05-S4W-CV6038 | CA05-06 UPENDING / SUB MODULE INSTALLATION ON PLATEN. |
| 87 | SV4-CA20-S5W-CV7374 | SA4-LEAK CHASE FABRICATION |

# Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 1. Legacy Work Packages (as of October 17, 2017) | | |
|---|---|---|
| **No.** | **Work Package Number** | **Title** |
| 88 | SV4-CA20-S4W-CV5773 | PRE-USE INSPECTION OF SUPER LIFT LUGS |
| 89 | SV3-CA01-S5W-CV4138 | CA01-28 UNSAT STRUCTURAL IR & N&D REPAIR |
| 90 | SV3-CA01-S5W-CV4215 | CA01-14 PERFORM STRUCTURAL N&D & INSPECTION REPORT (IR) S561-004-14-0453 REWORK AND REPAIRS. |
| 91 | SV4-CA05-S4W-CV6022 | CA05-02 UPENDING / SUB MODULE INSTALLATION |
| 92 | SV4-2040-CEW-CV5841 | 120' ELEV, STUD WELDS/SUPPORTS |
| 93 | SV4-CA05-S5W-CV6028 | CA05-03 UNSATISFACTORY IRS AND N&D REPAIRS, E&DCRS AND LOOSE PARTS - STUDS |
| 94 | SV4-CA05-S4W-CV6027 | (DESIGN SOUTH ELEV.) OLP'S AND WELDED ATTACHEMNTS INSTALLATION |
| 95 | SV4-CA01-S5W-CV6426 | (BLANK) |
| 96 | SV4-CA05-S5W-CV6036 | CA05-05 UNSATISFACTORY IRS AND N&D REPAIRS, E&DCRS AND LOOSE PARTS - STUDS |
| 97 | SV4-CA05-S4W-CV6019 | (DESIGN NORTH ELEV.) OLP'S AND WELDED ATTACHMENTS INSTALLATION |
| 98 | SV3-CA20-S4W-CV1757 | INSTALLATION OF CA20 WALL 3 EMBED PLATES |
| 99 | SV3-CA20-S4W-CV2626 | CA20 SUB ASSEMBLY 2 WORK LIST ITEMS WB-W00119, WB-W00120, WB-W00121, WB-W00122, WB-W00123, WB-W00124, WB-W00125, WB-W00126 & WB-W00128 |
| 100 | SV3-CA20-S4W-CV2627 | CA20 SUB ASSEMBLY 2 WORK LIST ITEMS |
| 101 | SV3-CA20-S4W-CV2629 | CA20 SUB ASSEMBLY 2 WORK LIST ITEMS WB-W00168, WB-W00170, WB-W00171, WB-W00172, WB-W00267, WB-W00268, WB-W00269, WB-W00271, WB-W00272 & WB-W00273 |
| 102 | SV3-CA20-S4W-CV2630 | CA20 SUB ASSEMBLY 3 WORK LIST ITEMS WB-W00173, WB-W00174, WB-W00175, WB-W00176, WB-W00177, WB-W00178, WB-W00179, WB-W000-180, WB-W00181, WB-W00182, WB-W00183, WB-W00184, WB-W00264 & WB-W00270 |
| 103 | SV3-CA20-S4W-CV2201 | Unit 3 Nuclear Island - Torquing and Welding CA20 Module Basemat Attachment Brackets |
| 104 | SV4-CA05-S4W-CV6023 | DESIGN EAST ELEV OLPs AND WELDED ATTACHMENTS INSTALLATION |
| 105 | SV3-CA20-S5W-CV5114 | INSTALLATION OF OUTSTANDING CA20 MODULE COUPLER ASSEMBLIES |
| 106 | SV4-R106-R1W-ME8128 | Installation of R106 Module |
| 107 | SV4-CA20-V2W-CV7513 | INSTALL SUPER LIFT LUG AT CA20-10 |
| 108 | SV4-CA01-S5W-CV6410 | CA01-14 UNSAT IRs/N&Ds/E&DCRs/LOOSE PARTS - STRUCTURAL |
| 109 | SV3-PXS-PHW-ME5534 | FABRICATION/INSTALLATION OF PIPE SUPPORT FOR ISOMETRIC DRAWING SV3-PXS-PLW-293 |
| 110 | SV4-CA20-S5W-CV5611 | CA20-22 AND CA20-25 INSTALL ADDITONAL BRACING AND INSTALL PENETRATION HOLES |
| 111 | SV3-CA03-S4W-CV2257 | CA03 SUBMODULE WALL ASSEMBLY (15, 16, 17) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 1. Legacy Work Packages (as of October 17, 2017) | | |
|---|---|---|
| **No.** | **Work Package Number** | **Title** |
| 112 | SV3-PXS-PHW-ME5535 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-PXS-PLW-294 |
| 113 | SV3-PXS-PHW-ME5536 | FABRICATION/INSTALLATION OF PIPE SUPPORT FOR ISOMETRIC DRAWING SV3-PXS-PLW-295 |
| 114 | SV3-WRS-PLW-ME5776 | WRS LARGE BORE PIPING INSTALLATION (INCLUDES ISOMETRIC SV3-WRS-PLW-660, 664, 665) |
| 115 | SV4-SFS-P0W-ME5408 | INSTALLATION OF KB12 PIPING ISOMETRIC SV4-SFS-PLW-088 |
| 116 | SV4-SFS-P0W-ME5411 | INSTALLATION OF KB12 PIPING ISOMETRIC SV4-SFS-PLW-60B |
| 117 | SV3-WLS-PLW-ME0897 | Fabricate and Install WLS Embedded Piping Iso SV3-WLS-PLW-57A, B, C, and D |
| 118 | SV3-WLS-PLW-ME0896 | Fabricate and Install WLS Embedded Piping Iso SV3-WLS-PLW-57E |
| 119 | SV3-WLS-PLW-ME0895 | Fabricate and Install WLS Embedded Piping Iso SV3-WLS-PLW-57T and 57U |
| 120 | SV3-WLS-PLW-ME0534 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES ISOMETRIC SV3-WLS-PLW-931) |
| 121 | SV4-CA20-V2W-CV7515 | INSTALL SUPER LIFT LUG AT CA20-18 |
| 122 | SV3-CA20-S4W-CV0440 | CA20 SA4 EL 81'-0" Floor Installation (CA20-31) |
| 123 | SV4-CA05-S8W-CV8006 | CA05 LIFT LUGS INSTALLAITON |
| 124 | SV3-CA20-S4W-CV2582 | CA20 SUB ASSEMBLY 3 & 4 WORK LIST ITEMS WB-W00011, WB-W00012, WB-W00013, WB-W00014, WB-W00015 & WB-W00016 |
| 125 | SV4-CA20-V2W-CV7514 | INSTALL SUPER LIFT LUG AT CA20-21/22 |
| 126 | SV4-CA20-V2W-CV7517 | INSTALL SUPER LIFT LUG AT CA20-26 |
| 127 | SV4-CA20-V2W-CV7516 | INSTALL SUPER LIFT LUG AT CA20-29/30 |
| 128 | SV3-CA20-S4W-CV5101 | UNIT 3 CA20 CLEAN-OUT PORT INSTALLATION |
| 129 | SV3-SFS-P0W-ME6690 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC SV3-SFS-PLW-782 (LINE NUMBER SFS-PL-L121) |
| 130 | SV4-CA01-S5W-CV6425 | CA01-18 UNSATISFACTORY IRs/N&Ds/E&DCRs AND LOOSE PARTS - STUDS |
| 131 | SV3-KB13-KBW-ME2464 | FABRICATION OF KB13 SUMP COVER |
| 132 | SV4-CA04-S4W-CV2448 | STUD AND REBAR COUPLER INSTALLATION FOR UNIT 4 CA04 |
| 133 | SV3-WLS-PHW-ME0768 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWINGS WLS-PLW-93C, -445, -940 |
| 134 | SV4-CA04-S4W-CV2328 | CA04 WALL SUBMODULE ASSEMBLY |
| 135 | SV4-CA05-S4W-CV7026 | CA05-02 Temporary Attachments |
| 136 | SV3-CA01-S4W-CV2225 | CA01-37 FINAL INSTALLATION |
| 137 | SV3-CA02-S4W-CV2565 | CA02 BASEMAT INSTALLATION |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 1. Legacy Work Packages (as of October 17, 2017) | | |
|---|---|---|
| **No.** | **Work Package Number** | **Title** |
| 138 | SV4-CA05-S4W-CV6042 | CA05-07 & CA05-08 UPENDING /SUB-MODULE INSTALLATION |
| 139 | SV3-CA20-S4W-CV0435 | Installation of CA20 SA3 EL 92'-8 1/2" Floor Submodules (Submods 47, 48, 49, 50) |
| 140 | SV3-CA20-S4W-CV2291 | CA20 SUB ASSEMBLY 2, 3, & 4 REWORK FOR CLOSURE OF N&DS |
| 141 | SV4-KB22-KBW-ME7677 | INSTALLATION OF KB22 COMPONENTS |
| 142 | SV4-CA05-S4W-CV6031 | OLPs AND WELDED ATTACHMENTS INSTALLATION |
| 143 | SV4-CA20-S5W-CV5590 | CA20-18 UNSATISFACTORY IRS/N&Ds/E&DCRs AND LOOSE PARTS - STUDS |
| 144 | SV3-ML05-MLW-ME4775 | INSTALLATION OF CA01 WALL PENETRATIONS FOR ROOM 11305/11206 |
| 145 | SV3-SFS-P0W-ME7210 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC SV3-SFS-PLW-781 (LINE NUMBER SFS-PL-L037) |
| 146 | SV3-PXS-PHW-ME5537 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-PXS-PLW-296 |
| 147 | SV3-PXS-PHW-ME5538 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-PXS-PLW-297 |
| 148 | SV4-CA20-S4W-CV5758 | INSTALLATION OF SUB-MODULE CA20_30 |
| 149 | SV3-PXS-P0W-ME3393 | ASME Section III - Fabrication/Installation of Isometric# SV3-PXS-PLW-294 (CA03 Piping) |
| 150 | SV3-PXS-P0W-ME3394 | ASME Section III - Fabrication/Installation of Isometric# SV3-PXS-PLW-295 (CA03 Piping) |
| 151 | SV3-PXS-P0W-ME3395 | ASME Section III - Fabrication/Installation of Isometric# SV3-PXS-PLW-296 (CA03 Piping) |
| 152 | SV3-PXS-P0W-ME3396 | ASME Section III - Fabrication/Installation of Isometric# SV3-PXS-PLW-297 (CA03 Piping) |
| 153 | SV3-ML05-MLW-ME5524 | ASME SECTION III – FABRICATION/INSTALLATION OF CA03 PENETRATION SV3-11305-ML-P11 |
| 154 | SV3-ML05-MLW-ME5525 | Installation of CA03 Penetrations |
| 155 | SV3-ML05-MLW-ME5527 | ASME SECTION III – FABRICATION/INSTALLATION OF CA03 PENETRATIONS: SV3-11305-ML-P14, SV3-11305-ML-P15, SV3-11305-ML-P19, SV3-11305-ML-P20 |
| 156 | SV4-CA20-S4W-CV5618 | CA20-23 UPENDING/SUB-MODULE INSTALLATION |
| 157 | SV4-CA05-S4W-CV6026 | CA05-03 UPENDING / SUB MODULE INSTALLATION |
| 158 | SV3-1000-CRW-CV1465 | INSTALLATION OF REBAR FOR UNIT 3 SHIELD BUILDING CYLINDRICAL WALL (AZ 182.25 TO 341.25) FROM EL 66-6 TO 100. |
| 159 | SV4-CA05-MHW-CV6017 | CA05 SM01 THRU 08 VERTICAL LIFTING FRAM & BRACING INSTALLATION AND REMOVAL |
| 160 | SV3-WLS-PLW-ME0688 | FABRICATE AND INSTALL WLS EMBEDDED PIPING SHOWN ON ISOMETRIC DRAWING SV3-WLS-PLW-75E |
| 161 | SV0-PWS-PLW-ME1084 | FABRICATE AND INSTALL POTABLE WATER PIPING BETWEEN BUILDING 304 TO BUILDING 305. |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 1. Legacy Work Packages (as of October 17, 2017) | | |
|---|---|---|
| No. | Work Package Number | Title |
| 162 | SV3-WLS-PLW-ME0524 | INSTALLATION OF SMALL BORE WLS PIPING. (INCLUDES:SV3-WLS-PLW-936,-93A,-990) |
| 163 | SV3-VAS-PLW-ME0574 | INSTALLATION OF LARGE BORE VAS PIPING (INCLUDES ISOMETRICS SV3-VAS-PLW-340, -350) |
| 164 | SV3-WLS-PHW-ME0842 | FABRICATION/INSTALLATION OF SMALL BORE WLS PIPING SUPPORTS FOR ISOMETRIC SV3-WLS-PLW-33E |
| 165 | SV4-2040-CRW-CV5842 | 120' Elev. Rebar |
| 166 | SV4-WGS-P0W-ME7479 | INSTALLATION OF KB14 WGS PIPING |
| 167 | SV4-WGS-PHW-ME7480 | INSTALLATION OF KB14 WGS PIPE SUPPORTS |
| 168 | SV4-WLS-P0W-ME7488 | INSTALLATION OF KB16 WLS PIPING |
| 169 | SV4-WGS-P0W-ME7491 | INSTALLATION OF KB16 WGS PIPING |
| 170 | SV4-VWS-P0W-ME7494 | INSTALLATION OF KB16 VWS PIPING |
| 171 | SV3-1000-CCW-CV1523 | PLACEMENT OF CONCRETE OUTSIDE CVBH UP TO ELEV. 82'-6" |
| 172 | SV4-CA20-S5W-CV5605 | CA20-21 UNSATISFACTORY IRS / N&DS AND E&DCRS - STUDS |
| 173 | SV4-CA20-S5W-CV7372 | SA2-LEAK CHASE FABRICATION |
| 174 | SV4-CA20-S4W-CV5301 | CA20 WALL K2 WEST FACE - OLPs AND WELDED ATTACHMENTS INSTALLATION |
| 175 | SV4-2050-CRW-CV5853 | NS 141'-3" ELEV REBAR POUR #3 |
| 176 | SV4-CA01-S4W-CV6404 | UNIT 4 SUBMODULE CA01-13 INSTALLATION |
| 177 | SV4-2050-CRW-CV5851 | NS 141'-3" ELEV. REBAR POUR 1 |
| 178 | SV4-2050-CRW-CV5858 | NS 141'3" ELEV. REBAR POUR 6 |
| 179 | SV4-2050-CRW-CV5854 | NS 141'-3" ELEV. REBAR POUR 4 |
| 180 | SV4-WRS-P0W-ME5360 | FABRICATION/INSTALLATION OF SMALL BORE WRS LEAK CHASE PIPING INCLUDING SV4-WRS-PLW-850, 855, 856, 857, 858 AND 859 |
| 181 | SV4-WRS-P0W-ME5361 | FABRICATION/INSTALLATION OF SMALL BORE WRS LEAK CHASE PIPING INCLUDING SV4-WRS-PLW-851, -852, -853, -854 |
| 182 | SV4-WRS-P0W-ME5362 | FABRICATION/INSTALLATION OF SMALL BORE WRS LEAK CHASE PIPING INCLUDING SV4-WRS-PLW-85A, -85B |
| 183 | SV4-CA20-S4W-CV3266 | CA20-05 SUB-MODULE ERECTION |
| 184 | SV4-CA02-S4W-860104 | CA02-04 Temporary Attachments |
| 185 | SV4-CA01-S4W-CV6392 | CA01-10 SUB MODULE INSTALLATION |
| 186 | SV4-CA01-S4W-CV6436 | UNIT 4 SUBMODULE CA01-21 INSTALLATION |
| 187 | SV4-CA03-S4W-860181 | CA03 Wall Submodule Assembly (03, 04, 05, 06, 07) |
| 188 | SV4-CA03-S4W-860182 | CA03 Wall Submodule Assembly (11, 12, 13, 14, 15) |
| 189 | SV4-CA03-S4W-860183 | CA03 Wall Sub module Assembly (01, 02, 03) |

# Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 1. Legacy Work Packages (as of October 17, 2017) | | |
|---|---|---|
| **No.** | **Work Package Number** | **Title** |
| 190 | SV4-CA03-S4W-860184 | CA03 Wall Submodule Assembly (15, 16, 17) |
| 191 | SV4-CA03-S4W-860188 | CA03 Lift Lugs Installation by SM |
| 192 | SV4-CA03-S4W-860190 | CA03 Wall Leak Chase Assembly |
| 193 | SV4-CA02-S4W-860152 | CA02-01 OLPs and Welded Attachments |
| 194 | SV4-WWS-PHW-ME5006 | INSTALLATION OF LARGE BORE WWS PIPING SUPPORTS (INCLUDING ISOMETRICS SV4-WWS-PLW-312, 314) |
| 195 | SV3-1233-C0W-850001 | 100'-0" ELEV, TUBE STEEL, AREA 3 |
| 196 | SV4-CA01-S5W-CV6402 | CA01-12 UNSAT IRs/N&DS/E&DCRs/LOOSE PARTS - STRUCTURAL |
| 197 | SV3-CA02-CAW-850000 | CA02 Module Installation |
| 198 | SV4-CA01-S4W-CV6388 | CA01-09 SUB MODULE INSTALLATION |
| 199 | SV3-SFS-P0W-ME3852 | FABRICATION/INSTALLATION OF PIPING FOR ISO SV3-SFS-PLW-421 |
| 200 | SV3-CA04-S4W-CV1551 | CA04 Wall Submodule Assembly (01,02,03,04,05) |
| 201 | SV3-SFS-P0W-ME3854 | FABRICATION/INSTALLATION OF PIPNG FOR ISO SV3-SFS-PLW-451 |
| 202 | SV4-CA01-S4W-CV6371 | CA01-05 SUB MODULE INSTALLATION |
| 203 | SV4-CA01-S5W-CV6462 | CA01-28 UNSAT IRs/N&Ds/E&DCRs/LOOSE PARTS - STRUCTURAL |
| 204 | SV4-CA01-S4W-CV6510 | CA01-42 SUB MODULE INSTALLATION |
| 205 | SV3-CA02-S4W-CV2567 | CA02-05 CONNECTION TO CA02-01 |
| 206 | SV4-CA01-S4W-CV6448 | CA01-24 SUB MODULE INSTALLATION |
| 207 | SV4-CA01-S5W-CV6538 | SA6 LEAK CHASE FABRICATION |
| 208 | SV4-CA01-S4W-CV6359 | CA01-02 SUB MODULE INSTALLATION |
| 209 | SV4-CA01-S4W-CV6363 | CA01-03 SUB MODULE INSTALLATION |
| 210 | SV3-WLS-PLW-ME0894 | Fabricate and Install WLS Embedded Piping Iso SV3-WLS-PLW-57J and 57K |
| 211 | SV3-WLS-PHW-ME3866 | FABRICATION/INSTALLATION OF SMALL BORE WLS PIPING SUPPORTS FOR ISOMETRICS SV3-WLS-PLW-284 |
| 212 | SV4-CA20-S4W-CV5307 | INSTALLATION OF SUB MODULE CA20-14 |
| 213 | SV4-2050-CEW-CV8153 | UNIT 4, TURBINE BUILDING 141' ELEVATION STUD WELDS POUR #5 |
| 214 | SV4-2050-CEW-CV8152 | UNIT 4, TURBINE BUILDING 141' ELEVATION STUD WELDS POUR #4 |
| 215 | SV3-WLS-PLW-ME0888 | Fabricate and Install WLS Embedded Piping Iso SV3-WLS-PLW-64E, F, G, H, I, and J |
| 216 | SV3-WLS-PLW-ME0889 | Fabricate and Install WLS Embedded Piping Iso SV3-WLS-PLW-569, 57L, M, and N |
| 217 | SV3-WLS-PLW-ME0891 | Fabricate and Install WLS Embedded Piping Iso SV3-WLS-PLW-57V,W, X, Y, Z, 640, 641, and 64R |
| 218 | SV4-2050-CEW-CV8150 | Unit 4, Turbine Building, 141' Elev. Stud Welds, Pour 2 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 1. Legacy Work Packages (as of October 17, 2017) | | |
|---|---|---|
| **No.** | **Work Package Number** | **Title** |
| 219 | SV4-2050-CEW-CV8151 | Unit 4, Turbine Building, 141' Elev. Stud Welds, Pour 3 |
| 220 | SV3-WLS-PLW-ME0886 | Fabricate and Install WLS Embedded Piping Iso SV3-WLS-PLW-64B, C, and D |
| 221 | SV0-PWS-P0W-ME1883 | FABRICATE AND INSTALL POTABLE WATER PIPING FROM BLDG. 301 CAPPED FUTURE SNC CONNECTION TO VISITOR CENTER. |
| 222 | SV3-2020-MEW-ME0736 | Assemble Condenser B Upper Tube Bundle |
| 223 | SV4-1220-EGW-EL3009 | INSTALL GROUND CABLES & GROUND PLATE INSERTS FOR AUXILIARY BUILDING OUTER WALLS ELEVATION 82'-6" TO 100'-0" & EXTEND RISERS TO ELEVATION 100'-0" |
| 224 | SV4-CA01-S4W-CV6432 | UNTI 4 SUBMODULE CA01-20 INSTALLATION |
| 225 | SV3-CWS-EQW-EL0062-C | TDL FOR SV3-CWS-EQW-EL0062-C |
| 226 | SV3-CA02-S4W-CV2562 | CA02-01 THRU CA02-03 UPEND AND ASSEMBLE |
| 227 | SV3-CA03-S5W-CV2572 | REWORK UNSAT IR'S |
| 228 | SV4-CA04-S4W-CV2624 | CA04 TOP FLANGE FABRICATION AND ASSEMBLY |
| 229 | SV3-4031-SHW-EL5454 | FABRICATE AND INSTALL CABLE TRAY SUPPORTS ANNEX BLDG AREA 1 ELEV 100' PARTIAL OF BATTERY CHARGER ROOM 40308 E OF ROW LINE (G) |
| 230 | SV4-KB11-KBW-KB4955 | MODULE KB11 STRUCTURAL FABRICATION |
| 231 | SV4-KB12-KBW-KB4956 | MODULE KB12 STRUCTURAL FABRICATION |
| 232 | SV4-CA20-S4W-CV5297 | INSTALLATION OF SUB MODULE CA20-12 |
| 233 | SV4-CA20-S4W-CV5302 | INSTALLATION OF SUB MODULE CA20-13 |
| 234 | SV3-1208-C0W-850100 | MAIN STEAM / FEED WATER PENETRATION CONCRETE PLACEMENT |
| 235 | SV4-CA20-S4W-CV5312 | CA20-15 Upending/Submodule Installation |
| 236 | SV4-CA20-S4W-CV5317 | INSTALLATION OF SUB MODULE CA20-16 |
| 237 | SV4-SFS-P0W-ME5407 | INSTALLATION OF KB12 PIPING ISOMETRICS SV4-SFS-PLW-086, -087 & SV4-WLS-PLW-60C, -60D, -60E, -60F, -60G, -60N, -672, -686 |
| 238 | SV4-CA20-S4W-CV5593 | CA20-18 UPENDING/SUB-MODULE INSTALLATION |
| 239 | SV4-CA20-S4W-CV5322 | INSTALLATION OF SUB MODULE CA20-17 |
| 240 | SV4-CA20-S4W-CV5603 | INSTALLATION OF SUB MODULE CA20-20 |
| 241 | VNC-230KV-ECW-003-C | TDL FOR VNC-230KV-ECW-003-C |
| 242 | SV4-CA20-S4W-CV5613 | INSTALLATION OF SUB-MODULE CA20-22 |
| 243 | SV4-CA20-S5W-CV5626 | CA20-25 UNSAT IR# & N&D STRUCTURAL REPAIRS |
| 244 | SV3-CA01-CAW-855000 | CA01, TOP CAP PLATE FABRICATION |
| 245 | SV4-CA20-S5W-CV5746 | CA20-28 UNSAT. IRS / N&DS - STRUCTURAL |
| 246 | SV4-CA20-S5W-CV5751 | CA20-29 UNSATISFACTORY IRS AND N&D REPAIRS - STRUCTURAL |
| 247 | VNC-CFA-CV-DRS-002-C | TDL FOR VNC-CFA-CV-DRS-002-C |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 1. Legacy Work Packages (as of October 17, 2017) | | |
|---|---|---|
| No. | Work Package Number | Title |
| 248 | SV4-CA01-S4W-CV6355 | SUBMODULE CA01-01 INSTALLATION |
| 249 | SV4-CA01-S4W-CV6375 | CA01-16 SUB MODULE INSTALLATION |
| 250 | SV4-CA01-S4W-CV6379 | CA01-07 SUBMODULE INSTALLATION |
| 251 | SV4-CA01-S4W-CV6384 | CA01-08 SUB MODULE INSTALLATION |
| 252 | WCD 08-1246058001-1275-C-ERC-002-C | TDL FOR WCD 08-1246058001-1275-C-ERC-002-C |
| 253 | SV4-CA01-V2W-860312 | CA01 INSTALL AND TEST LUG AT SM17 |
| 254 | SV4-CA01-V2W-860313 | CA01 INSTALL AND TEST LUG AT SM18 |
| 255 | SV4-CA01-V2W-860314 | CA01 INSTALL AND TEST LUG AT SM19 |
| 256 | SV4-WWS-PLW-ME0982-C | TDL FOR SV4-WWS-PLW-ME0982-C |
| 257 | SV4-CA22-CAW-850000 | CA22 MODULE FABRICATION |
| 258 | SV4-1110-CCW-CV1981-C | TDL FOR SV4-1110-CCW-CV1981-C |
| 259 | SV4-CA01-S4W-CV6444 | CA01-23 SUB MODULE INSTALLATION |
| 260 | SV4-CA01-S4W-CV6440 | CA01-22 SUBMODULE INSTALLATION |
| 261 | SV4-DWS-P0W-861278 | INSTALLATION OF DWS PIPING ON MODULE R155 |
| 262 | SV4-VWS-P0W-861284 | INSTALLATION OF VWS PIPING ON MODULE R155 |
| 263 | SV4-R155-MDW-861288 | INSTALLATION OF DUCTWORK AND SUPPORTS ON MODULE R155 |
| 264 | SV4-WRS-P0W-861343 | INSTALLATION OF WRS PIPING AND ISOMETRICS SV4-WRS-PLW-59A, 85C &85D |
| 265 | SV4-R104-R1W-861248 | STRUCTURAL FABRICATION OF R104 MODULE |
| 266 | SV4-CA03-S5W-861409 | UNSATISFACTORY IR's/ N&Ds/ loose parts |
| 267 | SV3-SFS-PHW-860255 | FABRICATION/ INSTALLATION OF PIPING SUPPORTS FOR ISO SV3-SFS-PLW-421, SV3-SFS-PLW-431, SV3-SFS-PLW-451 |
| 268 | SV4-CA03-S5W-861391 | CA03-06 UNSATISFACTORY IRs/ N&D's/E&DCRs/LOOSE PARTS |
| 269 | SV4-CA03-S5W-861399 | CA03-10 UNSATISFACTORY IRs/ N&D's/E&DCRs/LOOSE PARTS |
| 270 | SV4-CA03-S5W-861403 | CA03-12 UNSTAISFACTORY IRs/N&Ds/E&DCRs/LOOSE PARTS |
| 271 | SV4-CA03-S5W-861389 | CA03-05 UNSATISFACTORY IRs/N & Ds/ E & DCRs/ LOOSE PARTS |
| 272 | SV4-CA03-S5W-861407 | CA03-14 UNSATISFACTORY IRs/N & Ds/ E & DCRs/ LOOSE PARTS |
| 273 | SV4-CA03-S5W-861387 | CA03-04 UNSATISFACTORY IRs/N&Ds/E & DCRs/LOOSE PARTS |
| 274 | SV4-CA03-S5W-861405 | CA03-13 UNSATISFACTORY IRs/N&Ds/E&DCRs/LOOSE PARTS |
| 275 | SV4-CA03-S5W-861401 | CA03-11 UNSATISFACTORY IRs/N&Ds/E & DCRs/LOOSE PARTS |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 1. Legacy Work Packages (as of October 17, 2017) | | |
|---|---|---|
| **No.** | **Work Package Number** | **Title** |
| 276 | SV4-R155-R1W-861275 | STRUCTURAL FABRICATION OF MODULE R155 |
| 277 | SV4-R151-R1W-861256 | STRUCTURAL FABRICATION OF R151 MODULE |
| 278 | SV4-CA03-S5W-861397 | CA03-09 Unsatisfactory IRs/N&Ds/E&DCRs/Loose Parts |
| 279 | SV4-CA03-S5W-861395 | CA03-08 UNSATISFACTORY IRs/N&Ds/E&DCRs AND LOOSE PARTS |
| 280 | SV4-CA03-S5W-861383 | CA03-02 UNSATISFACTORY IRs/N&Ds/E&DCRs AND LOOSE PARTS |
| 281 | SV3-ML05-PNW-ME3173-C | TDL FOR SV3-ML05-PNW-ME3173-C |
| 282 | SV3-CWS-XEW-CV0055-C | TDL FOR SV3-CWS-XEW-CV0055-C |
| 283 | SV0-RWS-CCW-CV0238-C | TDL FOR SV0-RWS-CCW-CV0238-C |
| 284 | SV4-WWS-PLW-ME0961-C | TDL FOR SV4-WWS-PLW-ME0961-C |
| 285 | SV4-CA03-S5W-860185 | CA03 MISCELLANEOUS STUD REMOVAL/ INSTALLATION |
| 286 | SV3-FWS-PLW-ME1383-C | TDL FOR SV3-FWS-PLW-ME1383-C |
| 287 | SV4-R161-R1W-861294 | STRUCTURAL FABRICATION OF MODULE R161 |
| 288 | SV4-CA03-S5W-861393 | CA03-07 UNSATISFACTORY IRs/N&Ds/E&DCRs/LOOSE PARTS |
| 289 | SV4-CA03-S5W-861413 | CA03-17 UNSATISFACTORY IRs/N&Ds/E&DCRs/LOOSE PARTS |
| 290 | SV3-2141-SPW-850000 | FIRST BAY , 117'-6" ELEV. DECKING / GRATING |
| 291 | SV4-CA01-S4W-CV6396 | SUBMODULE CA01-11 INSTALLATION |
| 292 | SV4-CA01-S4W-CV6400 | SUBMODULE CA01-12 INSTALLATION |
| 293 | SV4-CA01-S4W-CV6416 | SUBMODULE CA01-16 INSTALLATION |
| 294 | SV4-CA01-S4W-CV6424 | SUBMODULE CA01-18 INSTALLATION |
| 295 | SV4-CA01-S4W-CV6428 | SUBMODULE CA01-19 INSTALLATION |
| 296 | SV4-CA20-S4W-CV6818 | INSTALLATION OF CA20 SA4 FLOOR (SUBMODULES CA20-31) |
| 297 | SV4-DWS-P0W-ME7497 | INSTALLATION OF KB16 DWS PIPING |
| 298 | SV4-KB27-KBW-ME7679 | INSTALLATION OF KB27 COMPONENTS |
| 299 | SV4-CA20-S5W-CV4022 | CA20-06 UNSATISFACTORY IRS / N&DS / E&DCRS AND LOOSE PARTS - STRUCTURAL |
| 300 | SV3-CAS-P0W-861068 | INSTALLATION OF CAS PIPING ON MODULE R251 |
| 301 | SV3-FPS-P0W-861076 | INSTALLATION OF FPS PIPING ON MODULE R251 |
| 302 | SV4-CA01-S4W-CV6456 | CA01-27 SUB MODULE INSTALLATION |
| 303 | SV4-CA01-S4W-CV6464 | CA01-29 SUB MODULE INSTALLATION |
| 304 | SV4-CA01-S5W-CV6360 | CA01-02 UNSATISFACTORY IRs / N&Ds / E&DCRs AND LOOSE PARTS - STUDS |
| 305 | SV4-KB28-KBW-ME7681 | INSTALLATION OF KB28 COMPONENTS |
| 306 | SV3-1000-CRW-CV2373 | FABRICATION OF REBAR FOR UNIT 3 NUCLEAR ISLAND |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 1. Legacy Work Packages (as of October 17, 2017) | | |
|---|---|---|
| **No.** | **Work Package Number** | **Title** |
| 307 | SV3-CA20-S5W-CV7519 | INSTALLATION OF COUPLERS PER APP-1230-GEF-171 |
| 308 | SV4-CA01-S4W-CV6468 | CA01-30 SUBMODULE INSTALLATION |
| 309 | SV3-CA20-S4W-CV1758 | INSTALLATION OF CA20 WALL 4 EMBED PLATES |
| 310 | SV4-CA01-V2W-860308 | CA01 INSTALL AND TEST LUG AT SM11 |
| 311 | SV4-CA01-V2W-860311 | CA01 INSTALL AND TEST LUG AT SM16 |
| 312 | SV4-CA01-V2W-860310 | CA01 INSTALL AND TEST LUG AT SM13 |
| 313 | SV4-CA01-V2W-860309 | CA01 INSTALL AND TEST LUG AT SM12 |
| 314 | SV4-CA01-V2W-860307 | CA01-INSTALL AND TEST LUG AT SM 04 |
| 315 | SV3-RNS-PHW-861211 | FABRICATION/INSTALLATION OF SV3-RNS-PLW-210 PIPE SUPPORTS |
| 316 | SV3-CA05-S4W-CV1868 | CA05 TEMPORARY ATTACHMENTS TO SHAPES |
| 317 | SV3-ML05-MLW-860961 | INSTALLATION OF PIPE PENETRATIONS 117'-135' NORTH SHIELD WALL |
| 318 | SV0-838-P0W-ME0207 | Fabrication and Installation of the Temporary Piping PWS & SDS (above slab) and Fixtures for the Material Issue, Building 122 |
| 319 | SV4-PGS-PHW-861262 | INSTALLATION OF PGS PIPE SUPPORTS ON MODULE R151 |
| 320 | SV4-WWS-PLW-ME0983 | Turbine Building WWS 82'-9" Elevation Embedded Piping Package 2 |
| 321 | SV3-FPS-P0W-ME2976-C | TDL FOR SV3-FPS-P0W-ME2976-C |
| 322 | SV3-PCS-P0W-850832 | INSTALL ISOMETRIC SV3-PCS-PLW-832 |
| 323 | SV3-CA01-S4W-CV3801 | CA01-44 SUB MODULE INSTALLATION |
| 324 | SV3-2141-ERW-862188 | ELECTRICAL CONDUIT SLEEVE FLOOR PENETRATION INSTALLATION IN THE 1ST BAY OF THE UNIT 3 TURBINE BUILDING AT ELEVATION 117' - 6" |
| 325 | SV4-CA03-S4W-860191 | CA03 Lift Lugs for NI set |
| 326 | SV4-WWS-PHW-861734 | INSTALLATION OF WWS PIPING SUPPORTS ON MODULE KB10 |
| 327 | SV4-WGS-P0W-861265 | INSTALLATION OF WGS PIPING ON MODULE R151 |
| 328 | SV4-VWS-P0W-861303 | INSTALLATION OF VWS PIPING ON MODULE R161 |
| 329 | SV3-WLS-MTW-862698 | INSTALLATION OF LEAK CHASE COLLECTION POTS SV3-WLS-MT-23A/23B |
| 330 | SV0-YFS-P0W-862359-C | TDL FOR SV0-YFS-P0W-862359-C |
| 331 | SV4-WWS-P0W-861733 | INSTALLATION OF WWS PIPING ON MODULE KB10 |
| 332 | SV3-CA01-S5W-CV4252 | CA01 POST PRODUCTION BENDING OF STUDS |
| 333 | SV3-CA01-S5W-CV5575 | SUBASSEMBLY 2: BASEMAT FABRICATION |
| 334 | SV3-CA01-S5W-CV5576 | SUBASSEMBLY 3: BASEMAT FABRICATION |
| 335 | SV3-CA01-S4W-CV3798 | CA01-40 SUB MODULE INSTALLATION |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 1. Legacy Work Packages (as of October 17, 2017) | | |
|---|---|---|
| **No.** | **Work Package Number** | **Title** |
| 336 | SV3-CA01-S5W-CV5577 | SUBASSEMBLY 4: BASEMAT FABRICATION |
| 337 | SV3-CA01-S5W-CV5579 | SUBASSEMBLY 6: BASEMAT FABRICATION |
| 338 | SV3-ML05-MLW-ME4409 | INSTALLATION OF CA01 ROOM 11303 PENETRATIONS |
| 339 | SV3-WGS-P0W-ME2972-C | TDL FOR SV3-WGS-P0W-ME2972-C |
| 340 | SV4-1210-EGW-EL1799 | INSTALL GROUNDING FOR WLL POURS 2, 6, 7, 8 & 9 |
| 341 | SV4-2020-MEW-ME1142 | Unit 4 Condenser B Upper Shell Heater Truss Assembly |
| 342 | SV4-2020-MEW-ME1143 | Unit 4 Condenser B Upper Shell Upper Truss Assembly |
| 343 | SV4-2020-MEW-ME1151 | Unit 4 Condenser C Flash Box Assembly |
| 344 | SV4-2050-CRW-CV5857 | NS 141'3" ELEV. REBAR POUR 5 |
| 345 | SV4-CA04-S4W-ME3052 | CA04 SOURCE RANGE DETECTOR WELLS INSTALLATION |
| 346 | SV4-CA04-S4W-ME3053 | CA04 POWER RANGE DETECTOR WELLS INSTALLATION |
| 347 | SV4-CA04-S4W-ME3054 | CA04 INTERMEDIATE RANGE DETECTOR WELLS INSTALLATION |
| 348 | SV3-1231-CPW-800000 | 100' Elev., Precast Panel Installation, Area 1 |
| 349 | SV3-CA20-S8W-CV2412 | CA20 MODULE CONCRETE REINFORCEMENT TERMINATORS |
| 350 | SV4-WRS-PLW-ME1581 | Installation of Large Bore WRS Piping Includes Isometrics SV4-WRS-PLW-57A, 570, 57H, 57G) |
| 351 | SV3-ML05-MLW-ME4960 | INSTALLATION OF CA01 PENETRATIONS |
| 352 | SV4-1000-CEW-CV1477 | UNIT 4 NUCLEAR ISLAND BASEMAT- EL 66'-6" EMBEDDED PLATES & ANCHOR BOLTS- AREA 1 & 2 |
| 353 | SV3-CA01-S4W-CV2064-C | TDL FOR SV3-CA01-S4W-CV2064-C |
| 354 | SV3-CA01-S4W-CV2095-C | TDL FOR SV3-CA01-S4W-CV2095-C |
| 355 | SV4-DWS-THW-861290 | HYDROSTATIC TESTING OF DWS PIPING ON MODULE R155 |
| 356 | SV4-FPS-THW-861289 | HYDROSTATIC TESTING OF FPS PIPING ON MODULE R155 |
| 357 | SV4-PGS-THW-861291 | HYDROSTATIC TESTING OF PGS PIPING ON MODULE R155 |
| 358 | SV4-WGS-THW-861293 | HYDROSTATIC TESTING OF WGS PIPING ON MODULE R155 |
| 359 | SV4-VWS-THW-861292 | HYDROSTATIC TESTING OF VWS PIPE SUPPORTS ON MODULE R155 |
| 360 | SV4-WLS-PLW-81CE-FP919 | REWORK SPOOLS SV4-WLS-PLW-81CE-1A, -1B & -2 AND SV4-WLS-PLW-81GE-1, -2A, -2B & -2C |
| 361 | SV3-VWS-PLW-05E-FP686 | MODIFY PIPE SPOOL SV3-VWS-PLW-05E-1 & -2 |
| 362 | SV3-CAS-PLW-731-FP143 | MODIFY PIPE SPOOL SV3-CAS-PLW-731-1 |
| 363 | SV4-MS12-MSW-862962 | INSTALLATION OF VAS-MS-06B |
| 364 | SV4-MS12-MSW-862961 | INSTALLATION OF VAS-MS-06A |
| 365 | SV4-PGS-THW-861272 | HYDROSTATIC TESTING OF PGS PIPING ON MODULE R151 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 1. Legacy Work Packages (as of October 17, 2017) | | |
|---|---|---|
| **No.** | **Work Package Number** | **Title** |
| 366 | SV4-FPS-THW-861270 | HYDROSTATIC OF FPS PIPING ON MODULE R151 |
| 367 | SV4-DWS-THW-861271 | HYDROSTATIC TESTING OF DWS PIPING ON MODULE R151 |
| 368 | SV4-WGS-THW-861274 | HYDROSTATIC TESTING OF WGS PIPING ON MODULE R151 |
| 369 | SV4-CAS-THW-863121 | PNEUMATIC TEST FOR CAS PIPING ON MODULE R151 |
| 370 | SV3-CCS-THW-863090 | HYDRO TESTING OF CCS PIPING ON MODULE R251 |
| 371 | SV3-WRS-THW-863095 | HDRO TESTING OF WRS PIPING ON MODULE R251 |
| 372 | SV3-FPS-THW-863093 | HYDRO TESTING OF FPS PIPING ON MODULE R251 |
| 373 | SV3-CVS-THW-863091 | HYDRO TESTING OF CVS PIPING ON MODULE R251 |
| 374 | SV3-VWS-THW-863094 | HYDRO TESTING OF VWS PIPING ON DODULE R251 |
| 375 | SV3-DWS-THW-863092 | HYDRO TESTING OF VWS PIPING ON MODULE R251 |
| 376 | SV4-CAS-PLW-081-FP612 | Modify Pipe Spools SV4-CAS-PLW-081-2 |
| 377 | SV4-KB20-KBW-863248 | SITE COMPLETION OF MODULE KB20 |
| 378 | SV3-VWS-PLW-05C-FP685 | MODIFY PIPE SPOOL SV3-3 |
| 379 | SV3-WLS-PLW-80CC-FP909 | REWORK SPOOLS SV3-WLS-PLW-80CC-1,-2A & -2B AND SV3-WLS-PLW-80GC-1,-2A,-2B & -2C |
| 380 | SV3-WLS-PLW-80CL-FP1012 | HYDROSTATIC TEST THE FABRICATED SPOOLS SV3-WLS-PLW-80CL-3A/3B |
| 381 | SV3-CVS-PLW-50A-FP313 | MODIFICATION OF PIPE SPOOL SV3-CVS-PLW-50A-1 |
| 382 | SV3-ECS-01-ET007 | 6.9KV BREAKER 2ND TRIP COIL TEST |
| 383 | SV3-R251-R1W-862870 | COMPLETE FABRICATION OF MODULE R251 STRUCTURAL |
| 384 | SV3-VWS-PLW-511-FP813 | MODIFICATION OF PIPE SPOOL SV3-VWS-PLW-511-1 |
| 385 | SV3-VWS-PLW-512-FP814 | MODIFICATION OF PIPE SPOOL SV3-VWS-PLW-512-1 |
| 386 | SV3-TCS-PLW-73AD-FP892 | MODIFICATION OF PIPE SPOOL SV3-TCS-PLW-73AD-1 |
| 387 | SV3-WRS-PLW-81E-FP990 | FABRICATION OF PIPE SPOOL SV3-WRS-PLW-81E-3 |
| 388 | SV3-VYS-PLW-163-FP846 | MODIFICATION OF PIPE SPOOL SV3-VYS-PLW-163-1 |
| 389 | SV4-WLS-PLW-81AX-FP914 | HYDROSTATIC TEST THE FABRICATED SPOOLS SV4-WLS-PLW-81AX-1/2/3A/3B |
| 390 | SV4-WLS-PLW-81CS-FP926 | Hydrostatic Test of the Fabricated Spools SV4-WLS-PLW-81CS/3A/3B |
| 391 | SV3-CFS-PLW-050-FP300 | MODIFICATION OF PIPE SPOOL SV3-CFS-PLW-050-1 |
| 392 | SV3-SFS-PHW-850411 | INSTALL LARGE BORE PIPE SUPPORTS FOR ISO SV3-SFS-PLW-411 |
| 393 | SV3-SFS-P0W-850411 | INSTALL LARGE BORE PIPE - ISOMETRIC SV3-SFS-PLW-411 |
| 394 | SV0-PWS-PLW-ME0266 | FABRICATION AND INSTALLATION OF THE POTABLE WATER SYSTEM HDPE PIPING FOR TRENCH 7 |
| 395 | SV3-2020-MEW-ME0853 | UNIT 3 CONDENSER C CONNECTION PIECE ASSEMBLY |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 1. Legacy Work Packages (as of October 17, 2017) | | |
|---|---|---|
| **No.** | **Work Package Number** | **Title** |
| 396 | SV3-CA01-S4W-CV2227 | CA01 SM 23 INSTALLATION |
| 397 | SV3-CA01-S4W-CV2558 | CA01-20 SUBMODULE INSTALLATION |
| 398 | SV3-CA01-S5W-CV2207 | CA01 SM 02 N&D REWORK & REPAIR |
| 399 | SV3-CA01-S5W-CV2278 | CA01-22 INSTALLATION OF STUDS, ANGLES, REBAR AND N&D REWORK |
| 400 | SV3-CA01-S5W-CV2376 | CA01-23 & CA01-24 N&D REWORK & REPAIRS |
| 401 | SV3-CA01-S5W-CV3027 | CA01-29 INTERNAL FABRICATION |
| 402 | SV3-CA01-S5W-CV3109 | CA01-19 PERFORM N&D & INSPECTION REPORT (IR) S540-001-14-0032 REWORK AND REPAIRS. |
| 403 | SV3-CA01-S5W-CV4140 | CA01-30 UNSAT IRS AND N&DS - STRUCTURE REPAIRS |
| 404 | SV3-CA01-S5W-CV5516 | SUBASSEMBLY 1: BASEMAT FABRICATION |
| 405 | SV3-CA01-S5W-CV5578 | SUBASSEMBLY 5: BASEMAT FABRICATION |
| 406 | SV3-CA01-S5W-CV5781 | SUBASSEBMLY 8 BASEMAT FABRICATION |
| 407 | SV3-CA01-V2W-CV4738 | PREP AND INSPECT SUPER LIFT LUGS |
| 408 | SV3-CA02-S4W-CV2563 | INSTALL CA02-01 PERMANENT WELDED ATTACHMENTS |
| 409 | SV3-CA02-S4W-CV3297 | CA02-04 SUB MODULE INSTALLATION |
| 410 | SV3-CA02-S4W-CV5778 | INSTALL CA02-02 PERMANENT WELDED ATTACHMENTS |
| 411 | SV3-CA02-S5W-CV5512 | CA02-05 Unsat IRs and N&D's - Studs |
| 412 | SV3-CA02-S5W-CV5574 | CA02-02 UNSAT IR AND N&D REPAIRS |
| 413 | SV3-CA02-S5W-CV5675 | CA02-04 STUCTURAL UNSAT IR'S AND N&D'S |
| 414 | SV3-CA02-S5W-CV5926 | CA02-01 STRUCTURAL UNSAT IR'S AND N&D'S |
| 415 | SV3-CA02-S5W-CV6185 | CA02 OVERLAY PLATE FABRICATION |
| 416 | SV3-CA01-S5W-CV3241 | CA01-31 UNSAT IR AND N&D REPAIRS |
| 417 | SV3-CA20-S4W-CV2488 | CA20 SUB ASSEMBLY 2 WORK LIST ITEMS WB-W00088, WB-W00099, WB-W00100, WB-W00101, WB-W00106, WB-W00107 & WB-W00108 |
| 418 | SV3-CA20-S4W-CV2628 | CA20 SUB ASSEMBLY 2 WORK LIST ITEMS WB-W00200,WB-W00201, WB-W00202, WB-W00203, WB-W00204, WB-W00205, WB-W00206, WB-W00207, WB-W00208, WB-W00209, WB-W00210, WB-W00211, WB-W00212, WB-W00213, WB-W00214, WB-W00215, WB-W00216, WB-W00217, WB-W00218, WB-W00219, |
| 419 | SV3-CA20-V2W-CV1848 | INSTALL STRUCTURAL BOLTING FOR CA20 LIFTING LUGS |
| 420 | SV3-WLS-PLW-ME0890 | Fabricate and Install WLS Embedded Piping Iso SV3-WLS-PLW-57O, P, Q, R, and S |
| 421 | SV3-WLS-PLW-ME0893 | Fabricate and Install WLS Embedded Piping ISO SV3-WLS-PLW-567, 568, 57F, G, and H |
| 422 | VNC-YARD-MIS-002 | INSTALL TEN 6" WELLS ONLY FOR HEAVE AND SETTLEMENT MONITORING SYSTEM |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 1. Legacy Work Packages (as of October 17, 2017) | | |
|---|---|---|
| **No.** | **Work Package Number** | **Title** |
| 423 | SV4-KB20-KBW-863104 | INSTALLATION OF KB20 |
| 424 | SV0-RWS-EWW-862861 | CABLE PULL AND TERMINATIONS FOR RWS PERMANENT WELL PUMPS 3 AND 4 |
| 425 | SV3-SFS-P0W-ME3853 | FABRICATION/INSTALLATION OF PIPING FOR ISO SV3-SFS-PLW-431 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

**Table 2. Completed and Voided Work Packages (as of October 17, 2017)**

| No. | Work Package Number | Title |
|---|---|---|
| 1 | SV3-2131-CSW-CV0217 | Turbine Building 1st Bay Stairs |
| 2 | SV3-2161-AGW-CV0218 | Turbine Building 1st Bay Roofing |
| 3 | SV3-2131-ADW-CV0215 | Turbine Building 1st Bay Doors |
| 4 | SV3-2161-SUW-CV0216 | Turbine Building 1st Helb Blowout Panels |
| 5 | SV3-2101-CCW-CV0214 | Turbine Building 1st Bay Walls |
| 6 | SV3-2131-SUW-CV0186 | Turbine Building 1st Bay Structural Steel |
| 7 | SV4-CA20-S5W-CV6856 | CA20-41 Unsat IRs & N&Ds - Structural |
| 8 | SV3-PXS-P0W-ME6982 | INSTALLATION OF SMALL BORE CA03 PXS PIPING (INCLUDES ISOMETRIC SV3-PXS-PLW-651) |
| 9 | SV3-PXS-PHW-ME6988 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-651 |
| 10 | SV0-SES-ERW-EL2298 | SV0-INSTALL SES PLANT SECURITY DUCT BANKS/EAST OF ANNEX - PHASE 6 |
| 11 | SV4-1208-SCW-CV7000 | Course 7 Unit 3 Shield Building |
| 12 | SV4-1208-SCW-CV7002 | Course 9 Unit 4 Shield Building |
| 13 | SV4-1208-SCW-CV7003 | Course 10 Unit 4 Shield Building |
| 14 | SV4-1208-SCW-CV7004 | Course 11 Unit 4 Shield Building |
| 15 | SV4-1208-SCW-CV7005 | Course 12 Unit 4 Shield Building |
| 16 | SV4-1208-SCW-CV7006 | Course 13 Unit 4 Shield Building |
| 17 | SV4-1208-SCW-CV7008 | Course 15 Unit 4 Shield Building |
| 18 | SV4-1208-SCW-CV7009 | Course 16 Unit 4 Shield Building |
| 19 | SV0-PWS-PLW-TP1259 | Fabricate & Install PWS Piping from Rest Room Trailer 205 to Rest Room Trailer on the North East Side of Turbine Conex |
| 20 | SV0-0000-M0W-MU0623 | Mock Up NI Basemat Mechanical Component Installation |
| 21 | SV0-6500-ETW-EL0881 | Install Temporary Power For The Administration Building 301 Construction |
| 22 | SV0-PWS-PPW-ME0347 | Stainless Steel Replacement of PWS piping at Tank Farm |
| 23 | SV0-892-PPW-ME0112 | Weld Test Building |
| 24 | SV0-874-PLW-TP0867 | Fabricate and Install Supports for One Fly Ash Pipe and One Cement Pipe at Batch Plant N0. 2 |
| 25 | SV0-841-EWW-EL0175 | Installation of Electrical Power to Carpenter and Sheet Metal Fab Shop (Building 133.) |
| 26 | SV0-0000-XEW-CV0020 | Install Erosion Control Measures per NOI 25 |
| 27 | SV0-851-PPW-ME0370 | Fabricate and Install Tie Ends to Craft Toilet Trailer # 128 |
| 28 | SV0-867-EWW-EL0158 | Electrical Service to Guard House at Gate 18 |
| 29 | SV0-8000-AYW-CV0166 | Install Decks, Canopies and Exterior Finishes for Temporary Construction Facilities Contract 1409 |
| 30 | SV3-CA20-S5W-CV4741 | CA20 OVERLAY PLATE REPAIR |
| 31 | SV0-892-CCW-CV0080 | Install Foundation for Weld Test Shop (Bldg. 134) |
| 32 | SV0-0000-CCW-CV0135 | Temporary Water Supply Foundations |
| 33 | SV3-RCS-PHW-ME0288 | ASME Demo Pipe Support |
| 34 | SV3-WLS-P0W-ME5927 | PERFORM REWORK OF FLOOR DRAIN SV3-WLS-PY-D08 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 35 | SV3-PY05-PYW-ME1528 | Installation of CWS Backwash Strainers (SV3-CWS-PY-S01A,B,C) |
| 36 | SV0-842-PPW-ME0114 | Pipe Fitting Shop |
| 37 | SV3-CA20-S5W-CV1459 | CA20-12 Liner Plate Weld Modification |
| 38 | SV3-WWS-PLW-ME0333 | Auxilary Building Embedded Piping |
| 39 | WCD 08-1246058001-1275-C-ERC-006 | Erosion Control - Diversion Ditch |
| 40 | SV0-0000-EWW-EL0137 | Relocation of Security Post No. 1 at the Main Entrance |
| 41 | SV0-854-EWW-EL0248 | Installation of Electrical Power to Craft Shelter - Insulation Fab Shop |
| 42 | SV3-CA20-MHW-CV0453 | Installation of Submodule Vertical Lifting Attachments (CA20-02, 06, 07A, & 07B) |
| 43 | SV0-8200-PLW-ME0313 | MAB Compressed Air & Bulk Gas Distribution |
| 44 | VNC-ED829-EL-MSC-026 | Relocation of 13.8 KV Overhead Lines at 108 |
| 45 | SV0-0000-CCW-CV0299 | Handicap Concrete Pad for Fire Training Facility |
| 46 | SV0-0000-XQW-CV0741 | Replacement Grating for Bridge Over 100 Year Ditch |
| 47 | SV0-G100-XEW-CV0404 | Nuclear Island Simulated Horizontal Waterproofing Membrane Testing |
| 48 | SV0-PWS-CCW-CV0003 | Potable Water System (PWS) Storage Tank (2) Common Foundation |
| 49 | SV3-2020-EGW-EL0401 | Electrical Grounding Installation for Turbine Building at Elevation 82'-9" |
| 50 | SV0-0000-XSW-CV0028 | River Road Improvements and Plant Entrance Roads (NOI 8) |
| 51 | SV3-KB10-KBW-ME0337 | KB10 Sump |
| 52 | SV3-PL03-PLW-ME1048 | Grit/Bristle Blasting of WRS & WWS Piping |
| 53 | SV3-WWS-PLW-ME0332 | Auxilary Building Embedded Piping |
| 54 | SV4-1200-CCW-CV1862 | UNIT 4 NUCLEAR ISLAND PLACEMENT OF CONCRETE PEDESTAL UNDER CVBH UP TO ELEV 71'-6" |
| 55 | VNC-230KV-ECW-003 | Erosion Control - NOI 13 |
| 56 | SV0-YFS-PLW-ME0043 | Fabrication and Installation of Trench 4 HDPE Yard Fire System |
| 57 | SV3-CA01-S5W-CV4150 | CA01-46 UNSAT IRs AND N&Ds - STRUCTURE REPAIRS |
| 58 | WCD 09-1246058001-1275-C-TEST-024 | Isopac Testing - Soil Isopac |
| 59 | WCD 08-1246058001-1275-C-ERC-009 | Install the Erosion Control Measures for NOI 9 |
| 60 | WCD 08-1246058001-1275-C-ERC-007 | Erosion Control - NOI 7 |
| 61 | SV0-846-EWW-EL0176 | Installation of Electrical Power to Rebar Module Pad (Building 102.) |
| 62 | SV0-832-EWW-TP0545 | Praxair Mobile Filling Station Electrical Installation |
| 63 | SV0-838-EWW-EL0261 | Electrical Installation for Material Issue Building (Bldg 122.) |
| 64 | SV0-838-PPW-ME0111 | Material Issue Building |
| 65 | SV3-1000-CEW-CV0296 | Unit Three Nuclear Island Basemat Embedded Steel Plates |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 66 | SV3-CA20-S5W-CV0900 | CA20-01 C6X13 Flange Repair |
| 67 | SV4-1000-CRW-CV1272 | Fabrication of Unit A Nuclear Island Basemat Construction Aids, Embeds and Anchor Bolts |
| 68 | SV4-1000-GCW-CV1423 | UNIT 4 NUCLEAR ISLAND TEMPORARY CONSTRUCTION STAIR CASES |
| 69 | VNC-CFA-ME-SDS-009 | Installation of Undergound Piping for the Sanitary Drainage System |
| 70 | VN3-NIA-CV-MSC-024 | Unit 3 Nulcear Island MSE Wall |
| 71 | SV3-1000-CEW-CV1063 | Replacement of Threaded No. 9 Rebar on CA20 Embed Plates |
| 72 | SV4-G100-CCW-CV0064 | Unit 4 Nuclear Island Mud Mat |
| 73 | SV0-PWS-PLW-ME0304 | Install Valve to Trench #1 |
| 74 | SV0-YFS-CCW-CV0002 | Yard Fire Protection (YFS) Storage Tank Ring Foundations |
| 75 | VN4-NIA-CV-MSC-025 | Unit 4 Nuclear Island MSE Wall |
| 76 | SV0-0000-PPW-ME0631 | Pipe Casings For Construction Support Gas/Air Lines |
| 77 | SV0-PWS-MTW-ME0036 | Potable Water System Tank Installation at Pumphouse #315 |
| 78 | SV3-WGS-THW-ME2706 | HYDROSTATIC TESTING OF KB04 WGS PIPING |
| 79 | SV0-DRS-XDW-CV0018 | Storm Drainage Plan River Road |
| 80 | SV0-YFS-PLW-ME1567 | Repair Yard Fire System (YFS) |
| 81 | WCD 08-1246058001-1275-C-ERC-023 | Erosion Control for NOI 23 |
| 82 | SV3-2020-CCW-CV0121 | U3 Turbine Bldg. Basemat EL 202'-9" (82'-9") Northwest Quad |
| 83 | SV0-1000-E0W-EL0397 | Electrical Work Package |
| 84 | SV3-1210-EGW-EL0355 | Electrical Grounding Installation for Areas 4, 5, 6 in Auxiliary Building at Elevation 66' 6" |
| 85 | VNC-CFA-CV-DRS-002 | Installation of the Storm Drainage Plan for NOI-7 |
| 86 | SV3-FWS-PLW-ME1405 | Unit 3 Turbine Building EL 100'-0' Insulation of Embedded FWS Piping |
| 87 | SV3-1210-EGW-EL0354 | Electrical Grounding Installation for Areas 1, 2, & 3 in Auxiliary Building at Elevation 66' 6" |
| 88 | SV3-CWS-PLW-ME0050 | Install PCP Piping for CWS Unit 3 Phase 2 Return Line |
| 89 | SV3-G100-CCW-CV0063 | Unit 3 Nuclear Island Mud Mat |
| 90 | SV3-CWS-PLW-ME0027 | Install PCP Piping for CWS Unit 3 Phase 1 Return Line |
| 91 | SV4-1110-CCW-CV1981 | Unit 4 Nuclear Island Placement of Grout Under CVBH - Rev. 0 |
| 92 | SV0-G100-XEW-CV0378 | Nuclear Island In-Situ Hortizontal Waterproofing Membrane Testing |
| 93 | VNC-CFA-ME-YFS-007 | Install Underground Piping for Yard Fire System |
| 94 | SV3-WRS-PLW-ME0325 | Auxilary Building Embedded Piping |
| 95 | VNC-NIA-CV-MSC-018 | Unit 3 & 4 Nuclear Island Blue Bluff Marl |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 96 | SV3-ME71-CCW-CV0093 | Unit 3 Cooling Tower Ring Beam Grading and Backfill |
| 97 | SV3-WLS-PLW-ME0684 | Fabricate and Install WLS Embedded Piping Iso SV3-WLS-PLW-756 |
| 98 | SV0-YFS-MTW-ME0031 | Yard Fire System Tank Istallation |
| 99 | VNC-CFA-ME-YFS-003 | Installation of Yard Fire System NOI 7 |
| 100 | SV3-WRS-PLW-ME0622 | Welding of WRS Piping Drain Hubs |
| 101 | SV3-CA01-S5W-CV4137 | CA01-28 UNSATISFACTORY IRS AND N&DS REPAIRS - STUDS |
| 102 | WCD 08-1246058001-1275-C-024 | Site Road Extension |
| 103 | SV3-CA20-S4W-ME4593 | REPAIR WORK OF SV3-CA20-GNR-000569 |
| 104 | VNC-COMM-SWS-007 | Temporary Pond for NOI 5 |
| 105 | SV0-CA20-VWW-CV0014 | CA20 Mockup Welding Package |
| 106 | SV0-MH90-MHW-RI0547 | For HLD Machinery Deck |
| 107 | SV3-RCS-PLW-ME0287 | ASME Demo Piping |
| 108 | VNC-CFA-ME-SDS-005 | Fabrication and Installation of Sanitary Drainage System in NOI 7 |
| 109 | SV0-SDS-PLW-ME0010 | Sanitary Drainage System Piping for Trench 6 |
| 110 | SV0-CA20-SPW-CV0038 | Setup/Disassemble of CA20 Module Mockup Platen |
| 111 | SV0-892-PPW-ME0208 | Fabrication and Installation of the Tempoary Piping PWS & SDS (above slab) and Fixtures for the Weld Test, Building 134 |
| 112 | SV0-MH90-MHW-RI0716 | Tension tie column Installation |
| 113 | SV0-0000-CCW-CV0302 | Install Foundation for (CR10) Pad 139 |
| 114 | VNC-COMM-CVW-008 | Installation of Heavy Haul Ramp |
| 115 | SV0-SAS-PLW-TP0965 | Fabricate and Install SAS Piping and a Drain line for CBI Fabrication Area |
| 116 | SV0-SDS-PLW-ME0249 | Remove Abandoned Underground Utilities (Trench 6) |
| 117 | SV0-0000-XEW-CV0019 | Erosion Control Measures for NOI 8 |
| 118 | SV0-0000-GCW-CV0283 | Demolition of Existing Warehouse |
| 119 | SV0-851-PPW-ME0278 | Fabrication and Installation of Temorary Piping PWS and SDS to craft toilet trailer #2 Bldg #125 |
| 120 | SV0-817-PPW-ME0279 | Fabrication and Installation of Temorary Piping PWS and SDS to FFD building #162 |
| 121 | SV0-854-PPW-ME0209 | Fabrication and Installation of the Tempoary Piping PWS & SDS (above slab) and Fixtures for the Craft Shelf Outer Module Fab. Area, Building 156 |
| 122 | SV0-0000-ERW-EL0066 | Electrical Race Way Installation for Temporary Construction Facilities |
| 123 | SV0-819-EWW-EL0282 | Electrical Power Installation to BLDG. 154 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 124 | SV0-PWS-CCW-CV0047 | Make up Well 3&4 Concrete Foundation |
| 125 | SV0-MH90-MHW-RI0339 | Pre-Assembly of Bigge Boom Selections |
| 126 | SV0-MH90-MHW-RI0981 | HLD Updates 505435-BIG-SCI-343L |
| 127 | SV0-802-PPW-ME0202 | Fabrication and Installation of the Tempoary Piping PWS & SDS (above slab) and Fixtures for the Truck Wash Facility, Building 136/146 |
| 128 | SV0-833-PPW-ME0212 | Fabrication and Installation of the Tempoary Piping PWS & SDS (above slab) and Fixtures for the Warehouse, Building 104 |
| 129 | SV0-804-CCW-CV0088 | Install Foundation for Air Compressor Station (Bldg. 141) |
| 130 | SV0-881-CCW-CV0016 | Installtion of the Containment Vessel Assembly Area Foundation Area 108 |
| 131 | SV4-1000-SYW-CV0411 | Welding of Steel Test Weights for Waterproofing Membrane Testing |
| 132 | SV0-891-CCW-CV0087 | Install Foundation for Material Testing Lab (Bldg. 112) |
| 133 | SV0-832-XEW-CV0714 | Excavate and Backfill for Potable Water Installation to Praxair Facility |
| 134 | SV0-841-CCW-CV0074 | Install Foundation for Carpenter Shop (Bldg. 133) |
| 135 | SV0-811-EWW-EL0168 | Electrical Feeder Installation for Time Office (Building 117) |
| 136 | SV0-MH90-MHW-RI0420 | HLD Tension Tie Column Universal Joint Installation |
| 137 | SV3-CWS-PLW-ME0026 | Install PCP Piping for CWS Unit 3 Phase 1 Supply Line |
| 138 | SV4-MG01-MGW-ME8793 | Installation of¿HSS Starter Cabinet(HSS-MP-02) |
| 139 | SV4-MG01-MGW-ME8794 | Installation of¿Generator Seal Oil Unit(HSS-MS-01) |
| 140 | SV3-1000-CRW-CV0629 | Unit 3 Nuclear Island Boot-Cleaning Station |
| 141 | SV0-0000-ELW-EL0032 | Installation of High Mast Lighting |
| 142 | SV0-8000-EWW-EL0345 | Power to New Survey Offices, Building 158, and GPS Base Tower |
| 143 | SV0-2020-PHW-ME0403 | Turbine Building Embedded Piping Support |
| 144 | SV0-PWS-PLW-ME0162 | Fabrication and Installation of Potable Water System |
| 145 | VNC-CFA-ME-YFS-001 | Installation of the Yard Fire System in NOI 6 & 7 |
| 146 | SV3-WLS-PLW-ME0685 | Fabricate and Install WLS Embedded Piping Iso SV3-WLS-PLW-758 |
| 147 | SV3-WLS-PLW-ME0687 | Fabricate and Install WLS Embedded Piping Iso SV3-WLS-PLW-75C |
| 148 | SV3-ME01-PLW-ME0920 | Condenser B Hotwell: Installation of Reheating Steam Piping |
| 149 | SV0-MH90-MHW-RI0721 | HLD Concrete Blocks |
| 150 | SV3-WWS-PLW-ME0405 | Turbine Building WWS 82'9 Elevation Embedded Piping Package 1 |
| 151 | SV0-0000-CCW-CV0157 | Concrete Foundation for Module Assembly Pad 149 |
| 152 | WCD 08-1246058001-1275-C-ERC-002 | Erosion Control - NOI 2 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 153 | SV0-YFS-PLW-ME0159 | Fabrication and Installtion of the Yard Fire System HDPE Piping for Trench #8 |
| 154 | SV3-KB13-KBW-ME0338 | KB13 Sump |
| 155 | VNC-CC87-CV-CCW-017 | Installation of Concrete Batch Plant Foundations |
| 156 | SV0-835-CCW-CV0075 | Install Foundation for Rigging Loft (Bldg. 143) |
| 157 | SV3-CA20-V2W-CV0949 | Install CA20 Guide Pin Collar Mounting Plate |
| 158 | SV0-0000-PLW-ME0140 | Temporary Piping for Construction City Water Supply |
| 159 | SV3-CA20-S4W-CV0308 | CA20 SA1 Wall Submodule Assembly (1, 2, 3, 4, 5, 6, 7, 8) |
| 160 | SV4-CWS-PLW-ME0188 | Unit 4 Phase 2 Return Line |
| 161 | SV4-CWS-PLW-ME0199 | Unit 4 CWS Phase 1 Return Line |
| 162 | SV3-CA20-S4W-ME4564 | REPAIR WORK OF SV3-CA20-GNR-000575 |
| 163 | VNC-COMM-WWS-002 | Install the Drainage CMP Pipe for NOI 4 |
| 164 | SV0-871-EWW-EL0245 | Installation of Electrical Power to Wash Pit |
| 165 | SV3-RCS-P0W-ME5583 | ASME DEMO ONLY |
| 166 | SV0-833-EWW-EL0161 | Electrical Installation for Construction Warehouse (Bldg 104) |
| 167 | SV3-CA05-S4W-CV1872 | CA05 WALL CONNECTION PLATES |
| 168 | SV3-RCS-THW-ME0289 | ASME Demo Hydrostatic Test |
| 169 | SV3-CA01-S4W-CV2062 | FABRICATE LEAK CHASE PLUG BARS AND WELD END CAPS FOR LEAK CHASE FOR CA01 SUB ASSEMBLY 3 |
| 170 | SV0-804-EWW-EL0351 | Electrical Power Installation for Compressor Building (BLDG. 141) |
| 171 | SV3-CA01-S4W-CV2243 | CA01-46 SUBMODULE ERECTION |
| 172 | SV0-1000-EWW-TP0541 | Temporary power installation to Nuclear Island |
| 173 | SV3-CA20-S5W-CV1498 | "CA20 Rebar Splice Testing" |
| 174 | SV3-CA20-S4W-CV0424 | Installation of CA20 SA1 EL 92'-6" Floor Submodules (Submods 38, 39, 40, 41, 42) |
| 175 | SV3-2101-CRW-CV8647 | Unit 3, Turbine Building, First Bay Wall – Wall Mechanical Rebar from 140’ to 154’ |
| 176 | SV3-2101-CRW-CV8648 | Unit 3, Turbine Building, First Bay Wall – Wall Mechanical Couplers from 140’ to 154’ |
| 177 | SV3-2101-CRW-CV8649 | Unit 3, Turbine Building, First Bay Wall – Floor Mechanical Couplers at 148’-10” |
| 178 | SV3-2101-CRW-CV8650 | Unit 3, Turbine Building, First Bay Wall Embeds up to 154’ |
| 179 | SV3-2101-CRW-CV8652 | Unit 3, Turbine Building, First Bay Wall – Wall Mechanical Rebar from 154’ to 169’ |
| 180 | SV3-2101-CRW-CV8653 | Unit 3, Turbine Building, First Bay Wall – Wall Mechanical Couplers from 154’ t0 169’ |
| 181 | SV3-2101-CRW-CV8654 | Unit 3, Turbine Building, First Bay Wall – Floor Mechanical Couplers at 169’ |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 182 | SV3-2101-CRW-CV8655 | Unit 3, Turbine Building, First Bay Wall Embeds up to 169’ |
| 183 | SV3-2101-CRW-CV8656 | Unit 3, Turbine Building, First Bay Wall, Terminators up to 169’ |
| 184 | SV3-2101-CRW-CV8657 | Unit 3, Turbine Building, First Bay Elev. 117’ Slab – Rebar |
| 185 | SV3-2101-CRW-CV8658 | Unit 3, Turbine Building, First Bay Elev. 117’ Slab - Mechanical Couplers |
| 186 | SV3-2101-CRW-CV8659 | Unit 3, Turbine Building, First Bay Elev. 117’ Slab – Embeds / Anchor Bolts |
| 187 | SV3-2101-CRW-CV8660 | Unit 3, Turbine Building, First Bay Elev. 117’ Slab - Formwork |
| 188 | SV3-2101-CRW-CV8661 | Unit 3, Turbine Building, First Bay Elev. 117’ Slab - Grout |
| 189 | SV3-2101-CRW-CV8662 | Unit 3, Turbine Building, First Bay Elev. 135’ Slab – Concrete |
| 190 | SV3-2101-CRW-CV8663 | Unit 3, Turbine Building, First Bay Elev. 135’ Slab – Rebar |
| 191 | SV3-2101-CRW-CV8664 | Unit 3, Turbine Building, First Bay Elev. 135’ Slab - Mechanical Couplers |
| 192 | SV3-2101-CRW-CV8665 | Unit 3, Turbine Building, First Bay Elev. 135’ Slab – Embeds / Anchor Bolts |
| 193 | SV3-2101-CRW-CV8666 | Unit 3, Turbine Building, First Bay Elev. 135’ Slab - Formwork |
| 194 | SV3-2101-CRW-CV8667 | Unit 3, Turbine Building, First Bay Elev. 135’ Slab - Grout |
| 195 | SV3-2151-CRW-CV8668 | Unit 3, Turbine Building, First Bay Elev. 148’ Slab – Concrete |
| 196 | SV3-2151-CRW-CV8669 | Unit 3, Turbine Building, First Bay Elev. 148’ Slab – Rebar |
| 197 | SV3-2151-CRW-CV8670 | Unit 3, Turbine Building, First Bay Elev. 148’ Slab - Mechanical Couplers |
| 198 | SV3-2151-CRW-CV8671 | Unit 3, Turbine Building, First Bay Elev. 148’ Slab – Embeds / Anchor Bolts |
| 199 | SV3-2151-CRW-CV8672 | Unit 3, Turbine Building, First Bay Elev. 148’ Slab - Formwork |
| 200 | SV3-2151-CRW-CV8673 | Unit 3, Turbine Building, First Bay Elev. 148’ Slab - Grout |
| 201 | SV3-2161-CRW-CV8674 | Unit 3, Turbine Building, First Bay Roof Slab – Concrete |
| 202 | SV3-2161-CRW-CV8675 | Unit 3, Turbine Building, First Bay Elev. Roof Slab – Rebar |
| 203 | SV3-2161-CRW-CV8676 | Unit 3, Turbine Building, First Bay Elev. Roof Slab - Mechanical Couplers |
| 204 | SV3-2161-CRW-CV8677 | Unit 3, Turbine Building, First Bay Elev. Roof Slab – Embeds / Anchor Bolts |
| 205 | SV3-2161-CRW-CV8678 | Unit 3, Turbine Building, First Bay Elev. Roof Slab - Formwork |
| 206 | VNC-COMM-CVW-003 | Nuclear Island Units 3 & 4 Excavation "Big Dig" |
| 207 | SV3-CA20-S5W-CV1983 | PERFORM ADDITIONAL MISC WORK ON CA20-26/30 |
| 208 | SV0-RWS-MTW-ME0030 | Raw Water System Tank Installation |
| 209 | SV0-ER02-ERW-EL0358 | Electrical Feeder to Morgan's Pig Container |
| 210 | SV3-WRS-P0W-ME3650 | SV3-WRS-GNR-000058 REPAIR WORK FOR SV3-WRS-PLW-81G |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 211 | SV3-CA20-S4W-CV0883 | Installation of VAS-MS-06A/B Support Steel |
| 212 | SV3-WLS-PLW-ME0856 | Fabricate and Install WLS Embedded Piping shown on Isometric Drawing SV3-WLS-PLW-751 |
| 213 | SV3-ME71-CCW-CV0367 | Unit 3 Micropile Installation |
| 214 | VNC-COMM-CVW-004 | Geotechnical Borings for Balance of Plant Structures (3 Books) |
| 215 | SV3-CA20-S4W-CV1882 | CA20 WALL N OVERLAY PLATES INSTALLATION |
| 216 | SV3-CA20-S4W-CV2486 | CA20 SUB ASSEMBLT 2 WORK LIST ITEMS WB-W00002, WB-W00005 & WB-W00006 |
| 217 | SV3-CA20-S4W-CV1836 | FABRICATION OF CA20 OVERLAY PLATE |
| 218 | SV0-867-EWW-EL0251 | Installation of Electrical Power to Guard Shack & Non Manual Turnstiles |
| 219 | SV3-CA01-S5W-CV3310 | CA01-10 UNSATISFACTORY IRs AND N&D REPAIRS-STRUCTURAL REPAIRS |
| 220 | SV0-MH90-EGW-EL0236 | Electrical Grounding for the Heavy Lift Derrick |
| 221 | SV0-1000-EWW-TP0970 | Temp Power Feeder to Material Assembly Center |
| 222 | SV0-8000-EWW-TP0971 | Temporary Power to N.O.I.G 6 Mock Up Pad |
| 223 | SV4-WWS-PLW-ME0982 | Turbine Building WWS 82'-9" Elevation Embedde Piping Package 1 |
| 224 | SV0-SDS-PLW-ME0133 | INSTALLATION OF THE TRENCH #4 SANITARY DRAINAGE SYSTEM GRINDER PUMPS |
| 225 | VNC-CFA-ME-PWS-008 | Installation Of Underground Piping for the Potable Water System |
| 226 | SV3-WLS-PLW-ME0686 | Fabricate and Install WLS Embedded Piping Iso SV3-WLS-PLW-759 |
| 227 | SV3-2030-CCW-CV0132 | 100' EL Slab Mud Mat (Includes 1st Bay) |
| 228 | SV0-0000-CCW-CV0005 | Install Chemical Skid and Tanks Foundation |
| 229 | SV0-862-EWW-EL0254 | Electrical Feeder Installation to Safety, Medical, & Fire Facility (Building 142) |
| 230 | SV0-843-PPW-ME0104 | FABRICATION AND INSTALLATION OF THE TEMPORARY PIPING (BELOW SLAB) FOR THE ELECTRICAL SHOP |
| 231 | VNC-CFA-CV-MSC-010 | QORE CONCRETE |
| 232 | SV4-1210-EGW-EL0356 | Electrical Grounding Installation for Areas 1, 2, & 3 in Auxiliary Building at Elevation 66' 6" |
| 233 | SV0-652-E0W-EL0398 | Control Room Simulator Assembly |
| 234 | SV0-SDS-PLW-ME0048 | INSTALLATION OF GRINDER PUMP STATIONS FOR TRENCH 2&3 |
| 235 | VNC-09-COMM-WW-ME-000-0001 | WELL WATER FILL STATION FOR DUST CONTROL |
| 236 | WP 09-124658001-1275-M-DEMO-002 | NEW TITLE |
| 237 | VNC-COMM-CVW-009 | Installation of Erosion Control Measures for NOI 18 |
| 238 | SV0-0000-CCW-MU0632 | Nuclear Island Concrete Mock-up |

## Exhibit V – Legacy, WIP, and Completed Work Packages

**Table 2. Completed and Voided Work Packages (as of October 17, 2017)**

| | | |
|---|---|---|
| 239 | SV0-SDS-PPW-ME0259 | FIELD ROUTE SDS FROM BLDG. #121 AND 165 TO GRINDER PUMP 601A |
| 240 | SV0-0000-EKW-860957 | REPLACE TRIP LEVERS FOR LOAD CENTERS SV0-ZRS-EK-21 & 22 AT 315 BLDG |
| 241 | VNC-COMM-WWS-001 | INSTALLATION OF Y-DRAINAGE PIPE IN LAYDOWN AREA (NOI-7) |
| 242 | SV3-PGS-THW-ME3964 | HYDRO TESTING OF R161 MODULE PGS PIPING |
| 243 | VNC-YARD-MIS-002A | VNC-YARD-MIS-002A |
| 244 | WCD 09-1246058001-1275-C-YARD-025 | Top Soil Removal |
| 245 | SV0-846-PPW-ME0203 | Fabrication and Installation of the Tempoary Piping PWS & SDS (above slab) and Fixtures for the Rebar Fab. Shop, Building 102 |
| 246 | VNC-CFA-ME-RWS-001 | Installation of the Raw Water System in NOI 6 & 7 |
| 247 | SV3-CA01-S4W-CV2240 | CA01-30 SUBMODULE ERECTION |
| 248 | SV3-CWS-CCW-CV0155 | Install temporary pipi restraints on the Phase 1 CWS piping 90 degree elbow. |
| 249 | SV4-ME71-CCW-CV0321 | Installation of the Hot Water Inlet Tunnel (Unit 4) |
| 250 | VNC-CFA-ME-SDS-001 | Sanitary Drainage System Installation |
| 251 | WCD 09-1246058001-1270-M-PWS-001 | WORK CONTROL DOCUMENT - POTABLE WATER SYSTEM (PWS) |
| 252 | WCD 08-1246058001-1275-C-ERC-010 | The purpose of this Work Control Document is to document the installation of a portion of the Erosion Control Measures designated as NOI 10. The work plan is broken into 3 stages. |
| 253 | SV0-867-EWW-TP1054 | D&R AND INSTALLATION OF TEMPORARY POWER TO POST 8B SECURITY BOOTH |
| 254 | SV0-0000-CCW-CV0091 | Soil Screening Equipment Foundations |
| 255 | SV3-KB16-KBW-ME3710 | KB16-TEMPORARY REMOVAL AND RE-ATTACHMENT OF MODULE ASSEMBLY LIFTING LUG |
| 256 | SV3-KB04-KBW-ME3671 | SITE COMPLETION OF KB04 STRUCTURAL STEEL |
| 257 | SV0-YFS-EWW-EL0303 | Temporary Electrical Service To YFS |
| 258 | SV0-SDS-EWW-EL0300 | Electrical Installation of SDS Grinder Pumps MS-600G and MS-602C |
| 259 | SV0-SDS-EWW-EL0269 | ELECTRICAL INSTALLATION OF SDS GRINDER PUMPS MS-601A AND MS-600C |
| 260 | VNC-CFA-ME-CAS-010 | Installation of Piping for the Compressed Air System |
| 261 | WCD 08-1246058001-1275-C-ERC-004 | Erosion Control - NOI 4 |
| 262 | SV0-EFS-EFW-EL0139 | Installation of Generator at Building 147 |
| 263 | WCD 08-1246058001-1275-C-ERC-06A | Erosion Control - NOI 6A |
| 264 | SV0-EFS-EFW-EL0044 | Telecommunications for Construction City |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| | | |
|---|---|---|
| **Table 2. Completed and Voided Work Packages (as of October 17, 2017)** | | |
| 265 | SV4-WGS-MVW-ME6121 | Installation of KB04 / WGS Mechanical Equipment |
| 266 | SV0-804-PPW-ME0311 | Piping and Components for Air Compressor House |
| 267 | SV0-CA20-SPW-CV0065 | Installation of CA20 Platen in MAB |
| 268 | SV0-SDS-EWW-EL0314 | ELECTRICAL INSTALLATION OF SDS GRINDER PUMPS MS-600B, MS-602A & MS-602B |
| 269 | VNC-JE01-EL-MSC-029 | Temporary Water Solution for the Concrete Batch Plant and Dust Control |
| 270 | SV4-EZ80-EWW-EL0144 | Installation of Temporary 13.8 kV Cable to Facilitate Installation of CWS Piping |
| 271 | VNC-ED829-EL-MSC-028 | Temporary Power to 108 (CB&I Containment Vessel Assembly Area) |
| 272 | SV0-821-SSW-CV0263 | Installation of CA01 Platen in MAB |
| 273 | SV0-802-EWW-EL0252 | Installation of Electrical Power to Vehicle Repair Shop |
| 274 | SV3-CA20-S4W-CV2295 | REMOVAL OF CA20 LIFTING LUGS 168 AND 169 |
| 275 | SV0-8000-EWW-TP0763 | Electrical Installation to Form Fabrication Area |
| 276 | SV0-SDS-EWW-EL0250 | Electrical Installation of SDS Grinder Pump MS-601B and SDS Sewage Lift Station MS-503 |
| 277 | SV0-MH90-EWW-TP0624 | Electrical Power Installation to HLD area |
| 278 | SV3-2020-MEW-ME0947 | Assemble Condenser C Flash Box |
| 279 | SV0-8000-EWW-TP0446 | Temporary power installtion to MAB mini mobiles and itaac trailer |
| 280 | SV3-CAS-THW-ME4413 | HYDROSTATIC TESTING OF KB15 MODULE CAS PIPING |
| 281 | SV4-KB10-KBW-ME0962 | KB10 Sump (WWS-MT-06) Installation - Including Legs & Portion 1 only |
| 282 | SV3-CA20-S5W-CV1353 | CA20-01 Liner Plate Weld Rework |
| 283 | SV3-WWS-PLW-ME0334 | Embedded Pipe Installation |
| 284 | SV3-CA20-S5W-CV1420 | CA20-05 Submodule Stud Welding, Rebar Modifications and Misc. Rework/Repairs |
| 285 | SV3-WWS-PLW-ME0409 | Turbine Building WWS 82'9 Elevation Embedded Piping Package 3 |
| 286 | SV4-2020-CCW-CV0381 | U4 Turbine Building Condenser Pedestals |
| 287 | SV3-CA20-S5W-CV1460 | CA20-14 Liner Plate Weld Modification |
| 288 | SV3-WLS-PLW-ME0681 | Fabricate and Install WLS Embedded Piping Iso SV3-WLS-PLW-753 |
| 289 | SV3-KB04-KBW-ME2478 | SITE COMPLETION OF MODULE KB04 |
| 290 | SV3-MS12-MSW-ME0884 | Installation of VAS-MS-06A/B |
| 291 | SV0-RWS-CCW-CV0001 | Raw Water System (RWS) Storage Tank Ring Foundation |
| 292 | SV4-1000-CRW-CV1265 | INSTALLATION OF UNIT4 NUCLEAR ISLAND BASE MAT REINFORCING STEEL |
| 293 | VN4-XC10-CV-MSC-016 | Safety Related Backfill for Nuclear Island Unit 4 (18 Books) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| | | |
|---|---|---|
| **Table 2. Completed and Voided Work Packages (as of October 17, 2017)** | | |
| 294 | SV0-0000-ERW-EL0007 | Installation of Electrical Wmbeds Through the Module Assembly Building's (BLDG. #150) foundation. The electrical embeds will accomodate the future electrical service to BLDG. #150 |
| 295 | SV0-8700-PLW-ME0069 | Installation of Ive Plant piping and piping components |
| 296 | SV0-8200-MHW-CV0145 | OVERHEAD CRANE INSTALLATION IN THE MODULE ASSEMBLY BUILDING |
| 297 | SV0-8200-SSW-CV0090 | Module Assembly Building Crane Rail Installation |
| 298 | VNC-NIA-CV-MSC-027 | Category 1 & 2 Screening Operation |
| 299 | SV0-817-EWW-EL0344 | Temporary Power to Office Trailers for River Water Intake Contractor |
| 300 | SV4-CWS-XEW-CV0151 | Excavate and Backfill (Bedding) for CWS Piping (Phase 2 Supply and return lines) |
| 301 | SV0-0000-PLW-ME0025 | Installation of CAS Underground Piping for Trench 5 |
| 302 | VNC-CFA-ME-PWS-001 | INSTALLATION OF THE POTABLE WATER SYSTEEM IN NOI 6 & 7 |
| 303 | SV0-SM01-CSW-MU0898 | Fabrication and Field Erection(Except Concrete Placement) for the AP1000 Shield Building RS/SC Connection Zone and Air Inlet/Tension Ring |
| 304 | SV0-846-PPW-ME0106 | REBAR FAB SHOP |
| 305 | SV0-817-EWW-EL0410 | Power and Data Installation to Field Offices for Turbine and Reactor Buildings |
| 306 | SV0-804-PPW-ME0281 | The installation of the floor drain piping for the Air Compressor building #141 |
| 307 | VNC-CFA-EL-MSC-003 | EXCAVATION |
| 308 | SV4-CWS-CCW-CV0154 | Install Temporary Pipe Restaints for Supply/Return Elbows |
| 309 | SV0-874-PLW-ME0691 | Fabricate and Install Sprinkler Piping and Sprinklers for the the Batch Plant |
| 310 | SV0-0000-CCW-CV0117 | Bridge Slope Repairs |
| 311 | SV0-0000-PLW-TP1053 | Installation of Piping & Components to Temporary Toilet Trailer East of Units 3 Nuclear Island |
| 312 | SV0-812-CCW-CV0084 | Install Foundation for Dynamic Learning Center (Bldg. 154) |
| 313 | SV0-PWS-PPW-ME0256 | Flush and Chlorinate Potable Water Header in Building 120 |
| 314 | SV0-MH90-EWW-TP0448 | Assemble and Install Electrical Systems and Components for the Bigge 125 D Heavy Lift Derrick |
| 315 | SV0-8800-E0W-EL0293 | Electrical Service Installation for CB&I Office Trailers |
| 316 | SV0-843-PPW-ME0201 | Fabrication and Installation of the Tempoary Piping PWS & SDS (above slab) and Fixtures for the Electrical Shop, Building 132 |
| 317 | SV0-821-EWW-EL0262 | Electrical Power Installation to Welders in MAB building (Bldg 150.) |
| 318 | SV0-PWS-PLW-TP1127 | Fabricate and Install Potable Water from Building 156 to AMEC Trailer on East Side of Roadway |
| 319 | SV0-010-EWW-TP0625 | Electrical Power Installation to 111 pad |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 320 | SV0-854-CCW-CV0086 | Install Foundation for Craft Shelter (Bldg. 156) |
| 321 | SV0-853-CCW-CV0081 | Install Foundation for Craft Change Facility (Bldg. 124) |
| 322 | SV0-0000-PLW-TP1106 | Tie-In of Potable Water (PWS) and Sanitary Drains (SDS) Piping to Temporary Trailer 117 Annex |
| 323 | SV0-853-CCW-CV0082 | Install Foundation for Craft Change Facility (Bldg. 130) |
| 324 | SV3-2020-MEW-ME0948 | Area 111 Satellite: Condensers A & C Flash Box Temporary Supports |
| 325 | SV0-838-CCW-CV0085 | Install Foundation for Material Issue Warehouse (Bldg. 122) |
| 326 | SV3-CA20-ERW-EL1047 | Conduit Rework |
| 327 | SV0-0000-CCW-CV0046 | High Mast Lighting Concrete Foundation |
| 328 | SV0-833-CCW-CV0073 | Construction Warehouse Foundation |
| 329 | SV0-0000-CCW-CV0139 | Construction and Erection of Soil Screening in NOI-25 and NOI-28 |
| 330 | SV0-852-EWW-EL0298 | 120V/208V Electrical Service at Ice House |
| 331 | SV3-CA20-MHW-CV0923 | Installation of CA20-03 Vertical Lift Attachment Stiffeners |
| 332 | SV0-0000-ELW-TP0412 | Lighting for Gate 18 Heavy Haul Road |
| 333 | WCD 08-1246058001-1275-C-ERC-005 | Erosion Control - NOI 5 |
| 334 | SV0-MH90-VWW-CV0371 | Thermite Welding & Installation of HLD Crane Rail |
| 335 | SV0-0000-C0W-CV0359 | SCBA - Hazmat Training System |
| 336 | SV0-ME71-CCW-CV1031 | Testing of Lenton Position P9 Mechanical Rebar Splice for Cooling Tower Foundations |
| 337 | SV0-MH90-CCW-CV0292 | Installation of the HLD Ring Foundation and Associated Work Activities |
| 338 | SV3-1000-CRW-CV1017 | MECHANICAL COUPLER POST INSTALLATION THREAD INSPECTION |
| 339 | SV0-851-PPW-ME0554 | Construction Toilet Trailer 129 PWS, SDS, Piping from the Trailer to Tie-In Point |
| 340 | SV0-MH90-MHW-RI0350 | Assembly of the Bigge HLD Lower Slew Carriage |
| 341 | SV0-833-EWW-TP0978 | Building 104 Level C Storage Lighting |
| 342 | SV0-MH90-MHW-RI0859 | Receiving of the HLD |
| 343 | SV0-PWS-PLW-ME0029 | Fabrication and Installation of Temporary Piping for Batch Plant Operation |
| 344 | SV0-843-EWW-EL0170 | Installation of Electric Power to Electrical Shop (Building 132) |
| 345 | SV0-804-PPW-TP0418 | Assemble and Install Piping Supports for Air Compressor Piping, Bldg. 141 |
| 346 | VNC-COMM-CVW-005 | Erosion and Sediment Control Plan for NOI 11 |
| 347 | SV0-0000-ETW-EL0017 | Construction Temporary Power for Building 315 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 348 | SV0-851-PPW-ME0273 | Fabrication and Installation of Temp Piping (for PWS and SDS) between toilet trailer 127 and tie-in point |
| 349 | SV0-0000-PLW-ME0377 | Installation of Piping and Components to Bath Room Trailer |
| 350 | SV0-851-PPW-ME0272 | Fabrication and Installation of Temp Piping (for PWS and SDS) between toilet trailer 126 and tie-in point |
| 351 | SV0-MH90-MHW-RI0967 | Load Test of HLD |
| 352 | SV0-841-PPW-ME0108 | Carpenter Shop |
| 353 | SV0-EFS-EFW-EL0189 | Interchange of UPS at Building 147 |
| 354 | SV0-804-PPW-ME0396 | Install Air Compressor Equipment at Building 141 |
| 355 | SV0-874-PLW-ME0673 | Rotate One Fly Ash Pipe and One Cement Pipe 90 degrees West from Present Location at Batch Plant 2 |
| 356 | SV0-829-EWW-EL0160 | Electrical Installation for 30 Ton and 50 Ton Overhead Cranes at Modular Assembly Building |
| 357 | SV0-CA20-MHW-RI1909 | CONSTRUCTING HAMMERHEAD FOR TESTING CA20 LIFTING LUG ATTACHMENTS |
| 358 | SV0-8800-EWW-TP0414 | Temporary Power to CBI Trailors and Thomarios Trailors |
| 359 | SV0-851-PPW-ME0271 | Fabrication and Installation of Temp Piping (for PWS and SDS) between toilet trailer 119 and tie-in point |
| 360 | WCD 08-1246058001-1275-C-ERC-003 | Erosion Control - NOI 3 |
| 361 | SV0-853-EWW-EL0169 | Installation of Electric Power to Craft Change House No. 2 (Building 130) |
| 362 | SV0-832-PPW-TP0667 | Provide Potable Water to Praxair Facility |
| 363 | SV0-RWS-PLW-ME0634 | Fabricate and Install an Alternate Raw Water Supply to the Batch Plant |
| 364 | SV3-CA20-MHW-CV0765 | Installation of Submodule CA20-01 Vertical Lifting Attachments |
| 365 | SV0-851-PPW-TP0766 | InstallRestroom Trailer (PWS & SDS Piping) on South East Side Of Unit3 |
| 366 | SV0-853-PPW-ME0206 | Fabrication and Installation of the Tempoary Piping PWS & SDS (above slab) and Fixtures for the Craft Change #1, Building 124 |
| 367 | SV4-1000-VTW-CV0150 | Perform Shear Wave Velocity Testing of Nuclear Island Backfill |
| 368 | SV0-832-PPW-TP0703 | Fabricate and Install Compressed Gas Piping/Supports for Weld Test Bldg 134 |
| 369 | SV0-0000-XEW-CV0342 | Area 111 Excavation Preparation |
| 370 | SV0-833-PPW-ME0116 | Fabrication and Installation of the Temporary Piping (Below Slab) for the Warehouse |
| 371 | SV0-832-PPW-TP0882 | Provde compressed air service to buliding 136- |
| 372 | SV0-832-PPW-TP0704 | Install Compressed Air and Welding Gases to the 131 Bldg (Pipe Shop) |
| 373 | SV0-0000-CBW-CV0213 | Prefabricated CJ Bulkhead Panels for the Turbine Building |
| 374 | SV0-804-PPW-TP1094 | Route Condensate Drain from BLDG. 141 to Sanitary Sewer |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 375 | SV0-843-CCW-CV0079 | Install Foundation for Electrical I&C Shop (Bldg. 132) |
| 376 | SV0-834-CCW-CV0076 | Install Foundation for Bottle Gas Storage (Bldg. 135) |
| 377 | SV0-853-EWW-EL0174 | Installation of Electrical Power to Craft Change House No. 1 (Building 124.) |
| 378 | SV0-891-PPW-ME0253 | Fabrication and Installation of Temp. Piping Below Slab and to tie-in points) for the Test Slab |
| 379 | SV0-853-PPW-ME0110 | Craft Change #1 |
| 380 | SV0-8000-EWW-EL0242 | Installation of Electrical Power to Weld Test Shop and Gas Bottle Storage Building (Buildings 134 & 135.) |
| 381 | SV0-802-PPW-ME0105 | Truck Washing Facility |
| 382 | SV0-0000-CRW-MU0619 | Mock Up Basemat |
| 383 | SV0-852-PPW-ME0406 | Fabrication and Installation PWS & SDS Piping to Ice House Buildings No.144 |
| 384 | SV0-817-PPW-ME0109 | Dynamic Learning Center |
| 385 | SV0-8200-EWW-EL0067 | Electrical Installation for Modular Assembly Building (BLDG. 150) |
| 386 | SV4-2020-CEW-CV0968 | Unit 4 Turbine Building Construction Aids |
| 387 | SV0-0000-CCW-CV0617 | "Mock Up" Basemat Mudat |
| 388 | SV0-841-PPW-ME0205 | Fabrication and Installation of the Tempoary Piping PWS & SDS (above slab) and Fixtures for the Carpenter Shop, Building 133 |
| 389 | SV0-DRS-XDW-CV0011 | Install Storm Drainage System in NOI-10 Area (Construction Parking lot) |
| 390 | SV3-WRS-PLW-ME0328 | Auxilary Building Embedded Piping |
| 391 | SV3-PXS-THW-ME6275 | HYDROSTATIC TESTING OF KQ10 PXS PIPE |
| 392 | SV4-KB13-KBW-ME0963 | KB13 Sump (WRS-MT-01) Installation - Including Legs & Portion 1 only |
| 393 | SV3-1210-EGW-EL1065 | Unit 3 Auxillary Bldg EL.66'-6" Grounding Work Package for Walls 1, 2 |
| 394 | SV3-DWS-THW-ME3442 | HYDROSTATIC TESTING OF KB12 DWS PIPING |
| 395 | SV3-G100-XEW-CV0246 | Unit 3 Nuclear Island Horizontal Waterproof Membrane |
| 396 | SV3-CA01-S5W-CV3321 | CA01-05 UNSAT IRS AND N&DS REPAIRS - STRUCTURAL REPAIRS |
| 397 | SV4-WGS-PHW-ME6123 | INSTALL KB04 WGS PIPE SUPPORTS |
| 398 | SV3-WLS-P0W-ME2769 | KB16-INSTALLATION OF SMALL BORE SEAL WATER PIPING (ISOMETRICS SV3-WLS-PLW-110 & 113) |
| 399 | SV3-WWS-PLW-ME0408 | Turbine Building WWS 82'9 Elevation Embedded Piping Package 2 |
| 400 | SV0-813-EWW-EL0171 | Installation of Power to Communication Rooms in Building 120. |
| 401 | SV0-0000-XSW-CV0395 | Asphalt Repairs for the Existing Roadway into Units 1 & 2. |
| 402 | SV0-853-PPW-ME0211 | Construction Craft Change #2 Building above slab piping and fixtures. |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 403 | SV0-RWS-PLW-ME0291 | Water Supply from Shaw's Raw Water System (RWS) Tank to Morgan's Dust Control. |
| 404 | SV0-8700-PLW-ME0034 | TEMPORARY PIPING FOR BATCH PLANT |
| 405 | SV0-835-PPW-ME0204 | Construction Tool Room & Rigging Loft above slab piping and fixtures |
| 406 | SV0-0000-JTW-IC8995 | INSTALL REMAINING TUBING RUNS AT THE 315 BUILDING |
| 407 | SV3-CA20-S4W-CV2322 | CA20 SUB ASSEMBLY 1 PUNCH LIST ITEMS WB-W00064 |
| 408 | SV0-PWS-PLW-ME0305 | Install PVC water line and faucet from PWS outside of building #150 |
| 409 | SV0-DRS-XDW-CV0138 | Installation of 15" HDPE Storm Drain Pipe in Existing Concrete Ditch |
| 410 | VNC-PL87-ME-SDS-032 | Fabrication and Installation of the Sanitary Drainage System in NOI 12 |
| 411 | SV0-8200-SSW-RI0172 | Functional Testing, 125% Load Testing of the 30 Ton, 50 Ton Northern and 50 Ton Southern Overhead Cranes (MAB) |
| 412 | SV0-MH90-CCW-CV0164 | Installation of the HLD Counterweight Mudmat and Associated Work Activities |
| 413 | SV3-CWS-XEW-CV0055 | Excavate and Backfill (Bedding) for CWS Piping (Phase 2 Supply and Return Lines) |
| 414 | SV0-842-CCW-RI0268 | Installation of the 15 Ton Overhead Cran Hoist in Building 131 |
| 415 | SV0-RWS-CCW-CV0238 | Raw Water System- Pipe Stanchion Support Foundations |
| 416 | SV0-SDS-PLW-ME0023 | The Installation of the Sanitary Drainage System HDPE Piping for Trench 5 |
| 417 | SV0-8700-GCW-CV0040 | Installation of Temporary Concrete Batch Plant Structures. |
| 418 | SV3-WRS-PLW-ME0327 | Auxilary Building Embedded Piping |
| 419 | SV3-WRS-PLW-ME0329 | Auxilary Building Embedded Piping |
| 420 | SV3-WRS-PLW-ME0977 | Installation of Large Bore WRS Piping to KB13 |
| 421 | VN3-XC10-CV-MSC-015 | NUCLEAR ISLAND BACKFILL UNIT 3 |
| 422 | VNC-CFA-EL-MSC-002 | Temporary Power for the Unit #4 Makeup Well. |
| 423 | SV0-835-PPW-ME0107 | Construction Tool Room, M&TE, and Rigging Loft below slab and embedded piping. |
| 424 | SV0-YFS-CCW-CV0237 | Yard Fire System - Pipe Stanchion Support Foundations |
| 425 | SV0-RWS-PLW-ME0260 | Well water supply to Auger Cast Drilling Subcontractor area NOI-6 for Support of Construction for Cooling Towers Units 3 & 4 |
| 426 | SV0-851-PPW-ME0324 | Fabricate and install the temporary potable water and sanitary drainage piping for Construction City Trailers #101 and #115 for Construction City |
| 427 | SV0-8000-EWW-EL0264 | Electrical Service Installation for Morgan's Pug Mill. |
| 428 | SV0-854-PPW-ME0113 | Construction Craft Shelter/Insulation Fab Shop below slab and embedded piping. |
| 429 | SV0-8000-EWW-EL0255 | Electrical Service Installation for Morgan's Repair Shop and Cooling Tower Subcontractor |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 430 | SV0-CWS-PLW-ME0290 | CWS Rework Activities |
| 431 | SV3-RNS-MPW-ME1193 | Disassembly of Residual Heat Removal Pump A (SV3-RNS-MP-01A) |
| 432 | SV0-ME71-EWW-EL0317 | Temporary Power for Cooling Tower Subcontractor |
| 433 | SV4-CWS-PLW-ME0187 | Unit 4 CWS Phase 2 Supply Line |
| 434 | SV0-CWS-PLW-ME0369 | Miscellaneous Items for CWS |
| 435 | SV3-1000-VTW-CV0149 | Shear Wave Testing of NI Backfill |
| 436 | SV0-010-EWW-EL0136 | Electrical Installation for Pumphouse Switchgear Building |
| 437 | SV0-8000-EWW-TP1093 | Temporary Power to N.O.I. 7 South Subcontractor Complex |
| 438 | SV0-8700-GCW-CV0041 | Installation and erection of Ice Plant (all equipment and components) |
| 439 | SV0-YFS-PPW-ME0284 | Start-up and Flush the Yard Fire Water System for Construction City. The Yard Fire Water System Motor Driven Electrical Fire Pump start-up will be performed by the vendor. |
| 440 | SV4-WRS-PLW-ME0951 | Auxilary Building Embedded Piping |
| 441 | SV4-WRS-PLW-ME0952 | Unit 4 Condenser A: Installation of Hotwell Piping |
| 442 | SV4-WRS-PLW-ME0953 | Auxilary Building Embedded Piping |
| 443 | SV4-WRS-PLW-ME0954 | Auxilary Building Embedded Piping |
| 444 | SV4-WRS-PLW-ME0955 | Auxilary Building Embedded Piping |
| 445 | SV4-WRS-PLW-ME0956 | Installation of WRS Embedded Drain Piping and Drain Hubs |
| 446 | SV4-WRS-PLW-ME0957 | Auxilary Building Embedded Piping |
| 447 | SV4-WRS-PLW-ME0958 | Auxilary Building Embedded Piping |
| 448 | SV3-CA20-S4W-CV2165 | CA20 SUB ASSEMBLY 1 PUNCH LIST ITEMS WB-W00047 & WB-W00048 |
| 449 | SV3-ML05-MLW-ME1519 | Attachment of Welded Nelson Studs to Embedded Piping Penetrations 66'-6"-82'-6" Walls only |
| 450 | SV3-CA04-S5W-CV1550 | Fabrication of Submodule CA04-05 |
| 451 | SV3-RNS-MPW-ME1743 | Disassembly of Residual Heat Removal Pump B (SV3-RNS-MP-01B) |
| 452 | SV4-RWS-PLW-ME0070 | Miscellaneous Work on Makeup Well #4 |
| 453 | SV4-2020-CCW-CV0379 | U4 Turbine Building Condensate Pump Pit and WWS Sump |
| 454 | SV3-WRS-PLW-ME0330 | Auxilary Building Embedded Piping |
| 455 | SV4-2020-EGW-EL0402 | ELECTRICAL GROUNDING INSTALLATION FOR TURBINE BUILDING AT ELEVATION 82'9" |
| 456 | SV3-WLS-THW-ME6276 | HYDROSTATIC TESTING OF KQ10 WLS PIPE |
| 457 | VNC-PL87-ME-YFS-030 | Fabrication and Installation of the Yard Fire Water System for NOI 12 |
| 458 | SV4-CWS-CYW-CV0153 | Phase 1 Joint Grouting and Flowable Fill |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 459 | SV3-WLS-PHW-ME2221 | INSTALLATION OF PIPE SUPPORTS ON KB12 (FOR ISOMETRICS SV3-WLS-PLW-60A, 60M, 608) |
| 460 | SV3-WLS-THW-ME7062 | HYDROSTATIC TESTING OF KB15 WLS PIPING |
| 461 | SV3-CA20-S8W-CV1847 | Temporary Bracing for CA20 Lift |
| 462 | SV3-KQ11-KQW-ME6222 | KQ11 - WELDED TUBE FITTINGS AT COVER |
| 463 | SV0-0000-CCW-CV0148 | Concrete Repair of flume in 100 year ditch. |
| 464 | SV3-CA04-S5W-CV1549 | Fabrication of Submodule CA04-04 |
| 465 | VNC-CC00-CV-CCW-033 | Replacement of Concrete Liner for the 100 Year Ditch |
| 466 | SV0-PWS-PLW-ME0022 | Installation of PWS Underground Piping for Trench 5 |
| 467 | SV3-CA20-S5W-CV1393 | CA20-03 LINER PLATE WELD MODIFICATION |
| 468 | SV3-CA20-V0W-CV1852 | Unit 3 CA20 Installation of Alignment/Guide Pins |
| 469 | SV3-CA20-S5W-CV1436 | CA20-10 Liner Plate Weld Modification |
| 470 | SV3-CA02-S4W-CV5918 | CA02- LEAK CHASE FABRICATION |
| 471 | SV3-CA04-S5W-CV1547 | Fabrication of Submodule CA04-02 |
| 472 | SV3-WLS-PHW-ME2224 | INSTALLATION OF PIPE SUPPORTS ON KB12 (FOR ISOMETRICS SV3-WLS-PLW-60D, 672) |
| 473 | SV4-ME71-CCW-CV0098 | Unit 4 Cooling Tower Drilled Shaft Foundations |
| 474 | SV3-CWS-EQW-EL0062 | Electrical Continuity Installation for CWS-Phase 1 &2 |
| 475 | SV3-CA20-S4W-CV2292 | REMOVAL OF CA20 LIFTING LUGS 162 AND 163 |
| 476 | SV3-CA20-S4W-CV2294 | REMOVAL OF CA20 LIFTING LUGS 166 AND 167 |
| 477 | SV3-CA20-S4W-CV5148 | INSTALLATION OF REMAINING COUPLERS IN UNIT 3 CA20 MODULE |
| 478 | SV3-CA05-S5W-CV2211 | CA05 MILL OUT FILLET WELDS CA05-01 & CA05-06 PER E&DCR APP-CA05-GEF-055 |
| 479 | SV3-CA01-S4W-CV2094 | CA01-36 ERECTION |
| 480 | SV3-VWS-PHW-ME3158 | FABRICATE/INSTALL VWS PIPE SUPPORTS IN MODULE KB16 |
| 481 | SV3-SFS-P0W-ME2131 | INSTALLATION OF SMALL BORE KB12SFS PIPING (INCLUDING ISOMETRICS SV3-SFS-PLW-086,087,088,089) |
| 482 | SV0-1220-CPW-MU1652 | Fabrication of Auxiliary Bldg. Precast Concrete Panel Mockup Elevation 82ft 6in |
| 483 | SV3-1230-CYW-850000 | GROUT 100' ELEV., BEAM GAPS |
| 484 | SV3-4032-SHW-EL4036 | INSTALL CABLE TRAY SUPPORTS ANNEX BLDG AREA 2, ROOM 40326 SOUTH WEST |
| 485 | SV3-WLS-PHW-ME5869 | Fabrication/Installation of Pipe Supports for Isometric Drawing SV3-WLS-PLW-450. |
| 486 | SV3-4032-SHW-EL4037 | INSTALL CABLE TRAY SUPPORTS ANNEX BLDG AREA 2, ROOM 40326 SOUTH EAST |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 487 | SV3-4032-SHW-EL4038 | INSTALL CABLE TRAY SUPPORTS ANNEX BLDG AREA 2, ROOM 40326 NORTH EAST AREA |
| 488 | SV3-4032-SHW-EL4035 | INSTALL CABLE TRAY SUPPORTS ANNEX BLDG AREA 2, ROOM 40350 |
| 489 | SV3-WLS-PHW-ME5870 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-WLS-PLW-451 |
| 490 | SV3-MSS-P0W-800000 | U3 INSTALL MAIN STEAM SYSTEM (MSS) PIPING FROM AUX BLDG TO HP TURBINE |
| 491 | SV3-WLS-THW-ME2433 | HYDROSTATIC TESTING OF KB11 WLS PIPING |
| 492 | SV3-4032-SHW-EL5580 | FABRICATE AND INSTALL CABLE TRAY SUPPORTS ANNEX BLDG AREA 2, ELEV 100' ADDED SUPPORTS |
| 493 | SV3-WLS-THW-ME3954 | HYDROSTATIC TESTING OF CLASS E WLS PIPING IN MODULE KB38 |
| 494 | SV4-2101-CCW-CV0390 | UNIT 4, TURBINE BUILDING FIRST BAY WALLS, CONCRETE UP TO 122', POUR 1W |
| 495 | SV3-CA05-S5W-CV3400 | CA05 - OUT OF PLANE SHEAR REBAR #4 INSTALLATION |
| 496 | SV3-CA20-S4W-CV0425 | Installation of CA20 SA1 EL 100'-0" Floor Submodules (Submods 52 & 53)- RESERVED FOR RUSSELL FINDLEY |
| 497 | SV3-CA01-S5W-CV3311 | CA01-06 UNSATISFACTORY IRs AND N&D REPAIRS - STUDS |
| 498 | SV0-0000-XSW-CV0141 | Installation of Access Roads |
| 499 | SV3-CA01-S4W-CV2080 | CA01-21 SUBMODULE ERECTION |
| 500 | SV3-1200-CRW-CV1410 | UNIT 3 AUXILIARY BUILDING EL.66-6 "TO 82'-6" REBAR FOR WALLS,5,2,6 |
| 501 | SV3-CA01-S5W-CV3322 | CA01-10 UNSATISFACTORY IRs AND N&D REPAIRS-STUDS |
| 502 | SV4-WRS-PLW-ME1685 | Installation of Large Bore WRS Piping to KB13 |
| 503 | SV0-691-CRW-850000 | BUILDING 305, COMMUNICATION SUPPORT CENTER REBAR FABRICATION |
| 504 | SV4-WLS-THW-ME5555 | HYDROSTATIC TESTING OF KB11 PIPING ISOMETRICS SV4-WLS-PLW-67W |
| 505 | SV3-WLS-PLW-ME0680 | Fabricate and Install WLS Embedded Piping Iso SV3-WLS-PLW-752 |
| 506 | SV3-WRS-PLW-ME0331 | Auxilary Building Embedded Piping |
| 507 | SV3-1208-SCW-CV2709 | ADMINISTRATION WORK PACKAGE FOR TRIAL FIT-UP OF UNIT 3 SHIELD WALL PANELS PRIOR TO INSTALLATION |
| 508 | SV3-CA20-S4W-CV0319 | Installation of CA20 SA1 EL 66'-6" Floor Submodules (Submods 64, 65) |
| 509 | SV0-842-CCW-RI0258 | Installation of the 15 Ton Overhead Crane, Girders, and Rails in Building 131 |
| 510 | SV3-CA01-S5W-CV3307 | CA01-11 UNSAT IR & N&D STRUCTURE REPAIRS |
| 511 | SV4-WGS-PHW-ME7492 | INSTALLATION OF KB16 WGS PIPE SUPPORTS |
| 512 | SV3-WWS-PLW-ME0612 | Installation of Large Bore WWS Piping |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 513 | SV3-CA04-S5W-CV1548 | Fabrication of Submodule CA04-03 |
| 514 | SV4-1210-EGW-EL0357 | Electrical Grounding Installation for Areas 4, 5, 6 in Auxiliary Building at Elevation 66' 6" |
| 515 | SV3-CA20-S4W-CV2167 | CA20-SUB ASSEMBLY 1 PUNCH LIST ITEMS WB-W00049, WB-W00050, WB-W00051, WB-W00052, WB-W00053 |
| 516 | SV3-KQ10-KQW-ME4602 | SITE COMPLETION OF MODULE KQ10 |
| 517 | SV0-PWS-THW-TP1708 | Hydro Test Potable Water System (PWS) From Bldg 146 to BLdgs 184 & 181 |
| 518 | SV0-ZRS-EWW-TP1158 | Temp Power Feed to River Intake |
| 519 | SV3-CPS-PLW-ME1216 | Unit 3 Turbine Building EL 100'-0" Embedded CPS Piping |
| 520 | SV4-WWS-PLW-ME1649 | UNIT 4 TURBINE BUILDING EL 100'-0": EMBEDDED WWS PIPING PACKAGE #4 |
| 521 | SV3-CA01-S4W-CV2085 | CA01-07 SUBMODULE ERECTION |
| 522 | SV4-WLS-THW-ME5551 | HYDROSTATIC TESTING OF KB11 PIPING ISOMETRICS SV4-WLS-PLW-660 & -661 |
| 523 | SV3-1110-CCW-CV1482 | Grouting Under CVBH |
| 524 | SV4-WLS-THW-ME5552 | HYDROSTATIC TESTING OF KB11 PIPING ISOMETRICS SV4-WLS-PLW-60K, -60L, -602, -603, -604, -605, -606, -607, -609, -676, -678, -679, -67D, -67E, -67F, -67G, -67H, -67K, -67L, -67N, -67P, -67U, -682, -684, -685, -687, -688, -68D, & -68E |
| 525 | SV4-WLS-THW-ME5553 | HYDROSTATIC TESTING OF KB11 PIPING ISOMETRICS SV4-WLS-PLW-67C |
| 526 | SV3-FWS-PLW-ME1383 | Unit 3 Turbine Building EL 100’-0” Embedded FWS Piping |
| 527 | SV4-KB16-KBW-ME8899 | INSTALLATION OF VAPOR CONDENSER AND DEGASIFIER SEPARATOR ON KB16 |
| 528 | SV4-WLS-THW-ME5556 | HYDROSTATIC TESTING OF KB11 PIPING ISOMETRICS SV4-WLS-PLW-683 |
| 529 | SV0-8200-SSW-RI0241 | Overhead Crane: Reeving, and Load Block Set Up |
| 530 | SV4-WLS-THW-ME5554 | YDROSTATIC TESTING OF KB11 PIPING ISOMETRICS SV4-WLS-PLW-67Q & 67S |
| 531 | SV3-WLS-P0W-ME2136 | Installation of Small Bore KB12 WLS Piping (Includes Isometrics SV3-WLS-PLW-67X & 68A) |
| 532 | SV3-SFS-PHW-ME2217 | INSTALLATION OF PIPE SUPPORTS ON KB12 (FOR ISOMETRICS SV3-SFS-PLW-086, 087, 088, 089) |
| 533 | SV4-WWS-PLW-ME0961 | Auxilary Building Embedded Piping |
| 534 | SV3-WLS-P0W-ME2768 | KB16 - Installation of Small Bore Piping at Degasifier Separator Pumps (Isometrics SV3-WLS-PLW-111 & 112) |
| 535 | SV3-CA20-S5W-CV1510 | CA20 Miscellaneous Rework for Closure of N&D's |
| 536 | SV3-CA20-MHW-CV1387 | Installation of Submodule CA20-18, 19, 20, 21, 22A, 22B, 23, 24 25 Vertical LIfting Attachments |
| 537 | SV3-1200-CEW-CV0707 | U3 Auxiliary Building Embedded Steel Survey Verfication |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 538 | SV3-2000-X4W-CV0857 | Unit 3 Turbine Building Survey Verification |
| 539 | SV4-1200-CEW-CV1472 | Unit 4 Auxiliary Building Embedded Steel Survey Verification |
| 540 | SV3-2040-MLW-ME2938 | INSTALLATION OF EMBEDDED PIPING PENETRATION FLOOR SLEEVES (SLAB 3) |
| 541 | SV4-2000-X4W-CV1214 | Unit 4 Turbine Building Survey Verification |
| 542 | SV3-CA20-S5W-CV1018 | CA20-04 Stud Welding |
| 543 | SV3-WRS-PLW-ME0326 | Auxilary Building Embedded Piping |
| 544 | SV0-8000-EWW-TP1080 | Dismantle and Remove Electrical and Fiber Optic Components for the Amec Complex |
| 545 | SV3-1200-CRW-CV1408 | UNIT 3 AUXILIARY BUILDING WALLS EL.66'-6 "TO 82'-6" REINFORCING STEEL FOR WALLS,1,4,25 |
| 546 | SV4-WWS-PLW-ME0960 | Auxilary Building Embedded Piping |
| 547 | SV3-KB16-KBW-ME3058 | KB16 - INSTALLATION OF DEGASIFIER VACUUM PUMPS WLS-MP-03A & WLS-MP-03B |
| 548 | SV3-CA01-S5W-CV4222 | CA01-36 UNSATISFACTORY IRs AND N&D REPAIRS-STUDS |
| 549 | SV3-2060-MLW-ME3175 | TURBINE-GENERATOR DECK PIPE SLEEVE PENETRATIONS |
| 550 | SV3-2020-MEW-ME0946 | ASSEMBLE CONDENSER A FLASH BOX |
| 551 | SV3-1200-CRW-CV1412 | UNIT 3 AUXILIARY BUILDING EL.66-6 "TO 82'-6" REBAR FOR WALLS,3,7,15 |
| 552 | SV0-DRS-XDW-CV0045 | Storm Water Drainage System (DRS) Installation in NOI-7 Area |
| 553 | VNC-PL87-ME-PWS-031 | Fabrication and Installation of the Potable Water System for NOI 12 |
| 554 | SV3-2020-CCW-CV0120 | U3 Turbine Bldg. Basemat EL 202'-9" (82'-9") Southwest Quad |
| 555 | SV3-2020-CCW-CV0125 | Turbine Building 89’-2" to 100’ Walls |
| 556 | SV3-2020-CCW-CV0122 | Turbine Building Condenser Piers 82’-9" |
| 557 | SV3-WRS-PLW-ME0596 | Installation of Large Bore WRS Piping |
| 558 | SV0-838-PPW-ME0207 | Fabrication and Installation of the Tempoary Piping PWS & SDS (above slab) and Fixtures for the Material Issue, Building 122 |
| 559 | SV3-ME01-PLW-ME1001 | INSTALLATION OF REHEATER A & B EMERGENCY VENT PIPING (1ST AND 2ND REHEATERS) FOR UNIT 3 CONDENSER A |
| 560 | SV3-ML05-PNW-ME3173 | INSTALL INSULATION OF PENETRATIONS 11504-ML-P04 & P05 IN CA01 |
| 561 | SV3-CA01-S5W-CV4225 | CA01-38 UNSAT IRs AND N&Ds - STUD REPAIRS |
| 562 | SV3-MG01-MEW-ME4878 | FRONT AND MID STANDARD (F-STD & M-STD) SOLE PLATE INSTALLATION |
| 563 | SV3-KB10-MEW-ME2495 | Fabrication/Installation of North Sump Pumps WWS-MP-02A and WWS-MP-02B and associated equipment |
| 564 | SV3-CA20-S4W-CV2489 | CA20 SUB ASSEMBLY 3 & 4 WORK LIST ITEMS WB-W00037, WB-W00223, WB-W00224, WB-W00225, & WB-W00226 |
| 565 | SV3-CA01-S4W-CV2061 | FABRICATE LEAK CHASE PLUG BARS AND END CAPS |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 566 | SV4-1200-CRW-CV1740 | UNIT 4 NUCLEAR ISLAND AUXILIARY BUILDING-INSTALLATION OF REINFORCING STEEL ON EXTERIOR WALLS UP TO ELEVATION 82"-6" (WALL PLACEMENTS 1 THRU 8) |
| 567 | SV4-WLS-P0W-ME5415 | INSTALLATION OF KB12 PIPING ISOMETRIC SV4-WLS-PLW-68A |
| 568 | SV4-WLS-P0W-ME5414 | INSTALLATION OF KB12 PIPING ISOMETRIC SV4-WLS-PLW-67X |
| 569 | SV3-WLS-PHW-ME2223 | INSTALLATION OF PIPE SUPPORTS ON KB12 (FOR ISOMETRICS SV3-WLS-PLW-60B, 60H, 60J) |
| 570 | SV3-ML05-MLW-ME3412 | INSTALLATION OF CA03 PENETRATION |
| 571 | SV4-PL03-THW-ME1502 | Pressure Testing of WRS and WWS in the Unit 4 Auxiliary Building |
| 572 | SV3-CA01-S5W-CV4219 | CA01-33 IR STRUCTURAL AND N&D'S |
| 573 | SV3-2020-MEW-ME0740 | Assemble Condenser A Upper Shell Upper Truss |
| 574 | SV3-MG01-MEW-ME4879 | LOW PRESSURE TURBINES A, B, C AND TURNING GEAR SOEL PLATE INSTALLATION |
| 575 | SV3-1120-CYW-850000 | GROUT, REACTOR VESSEL SUPPORTS |
| 576 | SV0-RWS-JEW-861612 | INSTALL PRESSURE GAUGES AT WELL WATER PUMP 4 |
| 577 | SV3-CA01-S4W-CV2239 | CA01-29 SUBMODULE ERECTION |
| 578 | SV3-2020-MEW-ME0847 | Install Condenser B Upper Shell Heater Truss |
| 579 | SV3-CA01-S5W-CV3314 | CA01-48 UNSAT IRs AND N&Ds |
| 580 | SV3-CA01-S4W-CV2084 | CA01-06 Submodule Erection |
| 581 | SV3-WGS-THW-ME3960 | HYDRO TESTING OF R155 MODULE WGS PIPING |
| 582 | SV0-PWS-MTW-861924 | REMOVE AND RE-INSTALL THE PWS TANKS AT THE 315 BUILDING |
| 583 | SV0-0000-JEW-IC8994 | INSTALL REMAINING INSTRUMENTS AT THE 315 BUILDING |
| 584 | SV4-WRS-P0W-861251 | INSTALLATION OF WRS PIPING ON MODULE R104 |
| 585 | SV3-2060-MEW-ME3176 | TURBINE/GENERATOR DECK FIXATOR INSTALLATION |
| 586 | SV3-ML05-MLW-ME1499 | INSTALLATION OF EMBEDDED PIPING PENETRATIONS 66'-6"-82'-6" WALLS ONLY |
| 587 | SV4-1210-EGW-EL1811 | UNIT 4 GROUNDING SHIELD BUILDING WALL EL 66-6" TO 82'-6" |
| 588 | SV3-ML05-MLW-ME4926 | INSTALLATION OF CA01 PENETRATION 11502-ML-P03 |
| 589 | SV3-ML05-MLW-ME4912 | INSTALLATION OF CA01 WALL PENETRATION FOR ROOM 11206/11202 |
| 590 | SV0-ZRS-SSW-862411 | FABRICATE BASEPLATE ANS INSTALL ANCHOR BOLTS FOR DIESEL GENERATOR HVAC SUPPORTS |
| 591 | SV3-WWS-PHW-ME0784 | INSTALLATION OF LARGE BORE WWS PIPING SUPPORTS (INCLUDES ISOMETRICS SV3-WWS-PLW-313, 31C, 31D) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 592 | SV3-ML05-MLW-ME5526 | Installation of CA03 Penetration |
| 593 | SV0-RWS-MPW-ME1404 | Install Raw Water Pumps in Building 315 |
| 594 | SV0-YFS-P0W-862359 | REMOVE EXISTING ACTUATORS AND INSTALL NEW AUMA ACTUATORS ON SV0-YFS-PL-V003A & V003B |
| 595 | SV3-DWS-THW-ME3422 | HYDRO TESTING OF DWS PIPING IN MODULE R151 - ISO SV3-DWS-PLW-621 |
| 596 | SV3-ML05-MLW-ME6177 | Installation of Temp-Mat Wrap for Penetrations 11209-ML-P09, P12, P13 & P14 |
| 597 | SV3-WGS-P0W-ME2721 | Installation of Small Bore WGS Piping (Includes SV3-WGS-PLW-050, 101, 103, 105, 107) |
| 598 | SV0-YFS-THW-ME8750 | HYDROTEST YFS AT BLDG 315 |
| 599 | SV3-DWS-THW-ME3956 | HYDRO TESTING OF R155 MODULE DWS PIPING |
| 600 | SV0-YFS-P0W-ME9000 | YFS PIPING INSTALLATION AT BLDG 315 |
| 601 | SV3-ML05-MLW-ME7580 | INSTALLATION OF HALF-COUPLINGS AND THERMOWELLS PXS-JE-TE041/042/043/044 |
| 602 | SV3-1208-SCW-CV3087 | COURSE 3 UNIT 3 SHIELD BUILDING |
| 603 | SV0-RWS-P0W-ME6002 | FABRICATE AND INSTALL THE RWS WELL WATER TRANSFER PUMPS EQUIPMENT DRAINS |
| 604 | SV0-PWS-MPW-ME1403 | INSTALL POTABLE WATER PUMPS, HYPOCHLORITE SKID AND THE HYPOCHLORITE TANKS IN BUILDING 315 |
| 605 | SV0-YFS-PLW-ME0071 | YFS- Tank Area Installation- Balance of Plant Components Supporting Temporary Supply |
| 606 | SV0-ZRS-PLW-ME0919 | FABRICATE AND INSTALL DIESEL FUEL OIL LINES FOR BUILDING 315 |
| 607 | SV3-WLS-THW-ME3947 | HYDRO TESTING OF KB15 MODULE WLS PIPING |
| 608 | SV4-WGS-P0W-861305 | INSTALLATION OF WGS PIPING ON MODULE R161 |
| 609 | SV4-1110-CRW-CV1853 | CONTAINMENT CONCRETE REINFORCEMENT - EL. 71'-6" |
| 610 | SV3-CA20-S4W-CV2168 | CA20 Sub Assembly 1 Punch List Items WB-W00062, WB-W00063, & WB-W00065 |
| 611 | SV3-WLS-THW-ME3952 | HYDRO TESTING OF KB37 MODULE WLS CLASS D PIPING |
| 612 | SV3-WLS-THW-ME6277 | Hydro Testing of R216 WLS Piping |
| 613 | SV3-VWS-PHW-ME3155 | INSTALL VWS PIPE SUPPORTS ON R161 MODULE |
| 614 | SV3-FPS-THW-ME3957 | HYDRO TESTING OF R155 MODULE FPS PIPING |
| 615 | SV3-CA05-S8W-CV1871 | CA05 LIFT LUGS INSTALLATION |
| 616 | SV3-CA04-S5W-CV1546 | Fabrication of Submodule CA04-01 |
| 617 | SV0-EDS-EWW-EL3564 | 315 BLDG CBL. PULLING & TERMINATIONS FOR EDS/EDS9 SYSTEM |
| 618 | SV0-EHS-EWW-EL7450 | HEAT TRACE SYSTEM @ 315 BUILDING |
| 619 | SV0-846-CCW-CV0077 | Install Foundation for Rebar Fab Shop (Bldg. 102) |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 620 | SV0-PWS-M0W-862038 | INSTALL SUN SCREEN OVER THE PWS CHEMICAL INJECTION SKID |
| 621 | SV0-ZRS-ERW-EL2746 | FABRICATE SUPPORTS AND INSTALL OUTSIDE CABLE TRAY NXT004BB FROM LOAD BANK SV0-ZRS-LB-001 BACK TOWARDS 315 BLDG. |
| 622 | SV0-ZRS-EWW-860203 | INSTALL CABLE FROM SWITCHGEAR EK21 GATEWAY TO PLC MODBUS INTERFACE |
| 623 | SV3-VWS-P0W-ME2971 | FABRICATE AND INSTALL VWS PIPING FOR MODULE R161 (INCLUDES DRAWINGS SV3-VWS-PLW-320, SV3-VWS-PLW-350, SV3-VWS-PLW-420 & SV3-VWS-PLW-450) |
| 624 | SV3-CA01-S5W-CV4144 | CA01-39 UNSATISFACTORY IRS AND N&D REPAIRS-STUDS |
| 625 | SV4-WLS-P0W-861249 | INSATLLATION OF WLS PIPING ON MODULE R104 |
| 626 | SV0-YFS-PHW-ME9001 | YFS SUPPORT INSTALLATION OF BLDG 315 |
| 627 | SV0-EDS9-DCW-862001 | SV0-EDS9-DC-02 BATTERY CHARGER #2 |
| 628 | SV0-ZRS-PHW-ME5486 | INSTALL PIPE SUPPORTS ON THE DIESEL FUEL OIL LINES FOR BUILDING 315 |
| 629 | SV0-YFS-PHW-ME0926 | FABRICATE AND INSTALL PIPE SUPPORTS ON THE YARD FIRE WATER LINES FOR BUILDING 315 |
| 630 | SV0-PWS-P0W-861445 | FABRICATE AND INSTALL THE CPVC AND OTHER PLASTIC PIPING SYSTEMS ASSOCIATED WITH THE POTABLE WATER SYSTEM (PWS) AT 315 BUILDING |
| 631 | SV3-CA01-S4W-CV2148 | CA01-10 SUBMODULE ERECTION |
| 632 | SV3-WGS-PHW-ME2985 | INSTALLATION OF WGS PIPING SUPPORTS IN MODULE R151 |
| 633 | SV0-RWS-PHW-ME0925 | Install Pipe Supports on Raw Water lines for Building #315 |
| 634 | SV3-WLS-MVW-ME2559 | Installation of KB11/WLS Mechanical Equipment |
| 635 | SV3-R104-R1W-ME0722 | INSTALLATION OF R104 MODULE |
| 636 | SV0-ZRS-PHW-ME8799 | Fabricate and Install Pipe Supports on the Diesel Fuel Oil Lines for Building 315 |
| 637 | SV3-WRS-P0W-ME2189 | UNIT 3 KB13: INSTALLATION OF LARGE BORE PIPING TO WRS-MP-01A (INCLUDES ISOMETRICS SV3-WRS-PLW-550 & 552) |
| 638 | SV4-ML05-MLW-ME6235 | Install CA05 Penetration SV4-11209-ML-I18 |
| 639 | SV3-WRS-P0W-ME2190 | UNIT 3 KB13: INSTALLATION OF LARGE BORE PIPING TO WRS-MP-01B (INCLUDES ISOMETRICS SV3-WRS-PLW-553, 557 & 55E) |
| 640 | SV3-WLS-PLW-ME0523 | INSTALLATION OF SMALL BORE WLS PIPING. (INCLUDES: SV3-WLS-PLW-720) |
| 641 | SV4-ML05-MLW-ME7960 | INSTALL SV4 CA01 PENETRATION SV4-11300-ML-P53 & SV4-11300-ML-P54 |
| 642 | SV3-CA01-S4W-CV2553 | INSTALLATION OF CA01-15 |
| 643 | SV0-SDS-PLW-TP0870 | Installation of SDS Cleanouts for Temporary Building |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| | | |
|---|---|---|
| **Table 2. Completed and Voided Work Packages (as of October 17, 2017)** | | |
| 644 | SV3-WGS-P0W-ME2770 | KB16 - INSTALL MISCELLANEOUS SMALL BORE PIPING (ISOMETRICS SV3-WGS-PLW-010, & 543) |
| 645 | SV3-1208-CCW-CV8408 | CONCRETE IN COURSE 2 SHIELD BUILDING PANELS |
| 646 | SV3-KB16-KBW-ME2759 | KB16 - INSTALLATION OF LIQUID SEAL WATER HEAT EXCHANGER |
| 647 | SV3-WRS-P0W-ME2192 | UNIT 3 KB13: INSTALLATION OF SMALL BORE PIPING (INCLUDES ISOMETRICS SV3-WRS-PLW-551, 554, 555, 55F & 55G) |
| 648 | SV4-WLS-P0W-ME5413 | INSTALLATION OF KB12 PIPING ISOMETRICS SV4-WLS-PLW-60B, 60H, 60J |
| 649 | SV4-WLS-P0W-ME5412 | INSTALLATION OF KB12 PIPING ISOMETRICS SV4-WLS-PLW-60A, -60M, -608 |
| 650 | SV3-CA05-S4W-CV1873 | CA05 ANGLE SEATS |
| 651 | SV3-WLS-P0W-ME2134 | INSTALLATION OF SMALL BORE KB12 WLS PIPING (INCLUDES ISOMETRICS SV3-WLS-PLW-60E, 60F & 60G) |
| 652 | SV3-CA01-S5W-CV4214 | PERFORM REWORK ON IDENTIFIED STUD RELATED DEFICIENCIES FROM INSPECTION REPORT (IR) S540-001-14-0061 FOR CA01-14, ALSO PERFORM N&D REWORK AND REPAIRS AS INDICATED IN THE APPROVED DISPOSITIONS |
| 653 | SV3-CA01-V2W-CV2104 | CA01 INSTALL AND TEST LUG AT SM19 |
| 654 | SV0-RWS-PLW-ME0163 | Fabrication and Installation of the Trench #7 Raw Water System Piping |
| 655 | SV3-CA01-S5W-CV2475 | CA01-08 UNSAT IR REPAIR |
| 656 | SV3-KB16-KBW-ME2761 | KB16 - INSTALLATION OF DEGASIFIER SEPARATOR PUMP WLS-MP-05B |
| 657 | SV4-KB04-KBW-ME6120 | FABRICATION OF KB04 MECHANICAL EQUIPMENT MODULE |
| 658 | SV0-0000-XGW-CV0663 | Pumphouse Switchgear Building #315 Grade for BLDG. Slab |
| 659 | SV0-0000-PLW-ME2477 | INSTALL PIPING AND PUMP FOR BATCH PLANT CHILLER CONDENSATE |
| 660 | SV3-WLS-THW-ME2432 | HYDROSTATIC TESTING OF KB12 WLS PIPING |
| 661 | SV0-RWS-PVW-862686 | CORRECT VALVE POSITION INDICATOR AND ROTATE VALVE 90 DEGREES BETWEEN PIPING FLANGES ON RWS VALVE #SV0-RWS-V012B IN ACCORDANCE WITH N&D SV0-RWS-GNR-000071 |
| 662 | SV0-YFS-EWW-EL3562 | 315 BLDG CBL PULLING & TERMINATIONS FOR YFS SYSTEM |
| 663 | SV3-CA01-S4W-CV4207 | CA01-02 Support Leg Installation (SA4) |
| 664 | SV3-WGS-PHW-ME3154 | INSTALL WGS PIPE SUPPORTS ON R161 MODULE |
| 665 | SV3-PGS-THW-ME3958 | HYDRO TESTING OF R155 MODULE PGS PIPING |
| 666 | SV3-CA20-S4W-CV2625 | CA20 SUB ASSEMBLY 2 WORK LIST ITEMS WB-W00117 & WB-W00118 |
| 667 | SV3-CA01-S4W-CV3800 | CA01-43 SUBMODULE INSTALLATION |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 668 | SV3-WLS-THW-ME3035 | KB16 - HYDROSTATIC TESTING OF WLS PIPING |
| 669 | SV0-010-CYW-CV5566 | Install Drywell Sump for Building 315. |
| 670 | SV0-PWS-PHW-861572 | FABRICATE AND INSTALL THE PIPE SUPPORTS AND BASEPLATES ASSOCIATED WITH ISOMETRICS SV0-PWS-PLW-980 |
| 671 | SV3-WLS-P0W-ME2144 | INSTALLATION OF SMALL BORE KB11 WLS PIPING (INCLUDING SV3-WLS-PLW-660, 661, 676, 67K, 67U, 684, 685, 687, & 68E) |
| 672 | SV3-WGS-P0W-ME2676 | Fabrication/Installation of WGS Piping Module KB14(Isometrics SV3-WGS-PLW-02A,04A,06A,07A,8A,9A,10E,030, 110 AND 130) |
| 673 | SV0-YFS-PLW-ME0024 | Installation of YFS Underground Piping for Trench 5 |
| 674 | SV3-CA01-V2W-CV2097 | CA01 INSTALL AND TEST LUG AT SM 04 |
| 675 | SV0-RWS-EWW-EL0943 | PUMPHOUSE SWITCHGEAR BLDG 315 CABLE PULLING AND TERMINATIONS - RWS |
| 676 | SV0-YFS-PVW-862706 | TROUBLESHOOT/ADJUST TRAVEL STOPS ON YSF VALVES # SV0-YFS-V008, AND SVO-YFS-PVW-V010 |
| 677 | SV3-WRS-P0W-ME2191 | UNIT 3 KB13: INSTALLATION OF LARGE BORE PIPING (INCLUDES ISOMETRICS SV3-WES-PLW-556 & 559) |
| 678 | SV3-WGS-P0W-ME2722 | INSTALLATION OF SMALL BORE WGS PIPING (INCLUDES SV3-WGS-PLW-051, 061, 071, 081, 091) |
| 679 | SV4-VWS-PHW-861285 | INSTALLATION OF VWS PIPE SUPPORTS ON MODULE R155 |
| 680 | SV4-DWS-P0W-861299 | INSTALLATION OF DWS PIPING ON MODULE R151 |
| 681 | SV4-CAS-P0W-861267 | INSTALLATION OF CAS PIPING ON MODULE R151 |
| 682 | SV3-R161-R1W-ME0726 | Installation of R161 Commodity Module |
| 683 | SV3-FPS-PHW-ME2977 | INSTALLATION OF FPS PIPING SUPPORTS IN MODULE R151 |
| 684 | SV3-KB38-KBW-ME2346 | INSTALLATION OF KB38 COMPONENTS |
| 685 | SV4-WLS-PHW-861250 | INSTALLATION OF WLS PIPIPE SUPPORTS ON MODULE R104 |
| 686 | SV4-DWS-PHW-861300 | INSTALLATION OF DWS PIPE SUPPORT ON MODULE R161 |
| 687 | SV3-DWS-P0W-ME2978 | INSTALLATION OF DWS PIPING IN MODULE R151 ISO SV3-DWS-PLW-621 |
| 688 | SV3-CCS-PHW-ME0801 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-CCS-PLW-522, 540 |
| 689 | SV3-CA20-S5W-CV1752 | PERFORM MISC REWORK/REPAIRS ON FLOOR MODULES FOR CA20 |
| 690 | SV0-010-PHW-ME9016 | Install Baseplates and Anchor Bolts for the Potable Water System (PWS) System at the 315 Building |
| 691 | SV0-RWS-P0W-862358 | FABRICATION & INSTALLATION OF THE #4 WELL PIPING TO THE RWS STORAGE TANK |
| 692 | SV3-KB13-KBW-ME7437 | Installation of Radioactive Drain Sump Pump Cover |
| 693 | SV4-CA20-CAW-850001 | CA20 SHIMS AND GUIDE PINS |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 694 | SV3-CA01-V2W-CV2103 | CA01 INSTALL AND TEST LUG AT SM 18 |
| 695 | SV3-ME71-CCW-CV0092 | Unit 3 Cooling Tower Drilled Shaft Foundations |
| 696 | SV0-YFS-PLW-ME1198 | RELOCATE THE ELECTRIC FIRE WATER PUMP SKID TO THE 315 PUMP HOUSE |
| 697 | SV3-ML05-MLW-ME7638 | 100' SHIELD BUILDING FLOOR PENETRATIONS |
| 698 | SV0-817-EWW-TP1394 | TEMPORARY POWER FOR CONSTRUCTION STARTUP BUILDING 207 |
| 699 | SV0-ZRS-MGW-EL5569 | INSTALL AND ANCHOR THE DIESEL GENERATOR SV0-ZRS-MGW-001 AND ASSOCIATED COMPONENTS IN BUILDING 315 |
| 700 | SV0-ZRS-P0W-ME8858 | Fabricate and Install Piping for the above ground Diesel Fuel Oil Lines for Building 315 |
| 701 | SV4-KQ11-KQW-ME8910 | FABRICATION OF KQ11 LID |
| 702 | SV4-2020-CCW-CV0380 | U4 Turbine Building Condenser Bay 82’-9" Slab |
| 703 | SV0-ZRS-MTW-ME5567 | INSTALL DIESEL FUEL OIL TANK AND PUMP SKID @ BUILDING 315 |
| 704 | SV0-CWS-VRW-ME0053 | Rework Damaged Circulation Water System (CWS) (PCCP) Pipe Fittings |
| 705 | SV3-PY05-PYW-ME1462 | Installation of SWS In-Line Automatic Backwash Strainers in the Unit 3 Turbine Building El. 82'-9" (SWS-PY-S06A&SWS-PY-S06B) |
| 706 | SV3-VWS-P0W-ME2765 | KB16 - INSTALLATION OF SMALL BORE CHILLED WATER PIPING (ISOMETRIC SV3-VWS-PLW-385 &485) |
| 707 | SV3-ML05-MLW-ME1500 | Attachment of welded couplings to embedded piping penetrations 66'-6"-82'-6" Walls only |
| 708 | SV3-1000-CRW-CV0295 | Unit 3 Nuclear Island Reinforcing Steel |
| 709 | SV3-CA01-V2W-CV2102 | CA01 INSTALL AND TEST LUG AT SM17 |
| 710 | SV3-WLS-THW-ME3949 | HYDRO TESTING OF KB22 MODULE WLS PIPING |
| 711 | SV3-WLS-THW-ME3953 | HYDROSTATIC TESTING OF CLASS D WLS PIPING IN MODULE KB38 |
| 712 | SV3-WLS-THW-ME3950 | Hydro Testing of KB27 Module WLS Piping |
| 713 | SV3-WGS-THW-ME3966 | HYDROSTATIC TESTING OF WGS PIPING ON MODULE R161 |
| 714 | SV0-YFS-PLW-ME0918 | Fabricate and Install Yard Fire Water Lines for Building 315 |
| 715 | SV0-ZRS-EKW-EL2745 | INSTALL ELECTRICAL EQUIPMENT LOAD BANK SV0-ZRS-LB-001 AT PUMPHOUSE SWITCHGEAR BLDG. 315 |
| 716 | SV0-ZRS-THW-ME6273 | PERFORM HYDROSTATIC/PNEUMATIC TESTING ON THE DIESEL FUEL OIL LINES @ BUILDING 315 |
| 717 | SV0-PWS-P0W-862331 | SUPPORT FLUSH PLAN SV0-PWS-TFP-401 FLUSH PLAN |
| 718 | SV3-R155-KBW-ME3672 | SITE COMPLETION OF R155 SRUCTURAL STEEL |
| 719 | SV0-YFS-CCW-CV5434 | GROUT FOR ELECTRIC YARD FIRE WATER PUMP |
| 720 | SV0-PWS-EWW-EL3561 | 315 BLDG CBL PULLING & TERMINATIONS FOR PWS SYSTEM |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 721 | SV0-ZRS-EKW-EL5901 | INSTALLATION OF FLEXI-BAR BUS CONNECTIONS FOR LOAD CENTERS SV0-ZRS-EK-21 & 22 AT 315 BLDG |
| 722 | SV0-RWS-P0W-861787 | SUPPORT FLUSH PLAN SV0-14-RWS-001 FOR BUILDING 315 PIPING |
| 723 | SV3-SFS-THW-ME2431 | HYDROSTATIC TESTING OF KB12 SFS PIPING |
| 724 | SV3-CA05-S4W-CV1874 | CA05 NORTH SIDE WALL OVERLAY PLATES AND BEAM SEATS INSTALLATION |
| 725 | SV3-VWS-THW-ME4460 | HYDROSTATIC TESTING OF R161 VWS PIPING (CLASS E) |
| 726 | SV4-KB16-KBW-ME7487 | INSTALLATION OF KB16 DEGASIFIER VACUUM PUMPS |
| 727 | SV3-DWS-THW-ME3963 | HYDRO TESTING OF R161 MODULE DWS PIPING |
| 728 | SV3-VWS-THW-ME3959 | HYDRO TESTING OF R155 MODULE VWS PIPING |
| 729 | SV3-CCS-THW-ME3962 | HYDRO TESTING OF R161 MODULE CCS PIPING |
| 730 | SV3-ML05-MLW-ME4821 | INSTALLATION OF PENETRATION 1120-ML-P03 |
| 731 | SV4-CAS-PHW-861296 | INSTALLATION OF CAS PIPE SUPPORTS ON MODULE R161 |
| 732 | SV4-WWS-PLW-ME0959 | Installation of WWS Embedded Drain Piping and Drain Hubs |
| 733 | SV3-KB13-MEW-ME2462 | INSTALLATION OF KB13 SUMP PUMPS WRS-MP-01A & 01B |
| 734 | SV3-CWS-PLW-ME0049 | Unit 3 Circulating Water System (CWS) Phase 2 Supply Lines. |
| 735 | SV3-CA01-V2W-CV2099 | CA01 INSTALL AND TEST LUG SM12 |
| 736 | SV3-VWS-THW-ME3965 | HYDROSTATIC TESTING OF VWS PIPING ON MODULE R161 |
| 737 | SV3-CA01-V2W-CV2098 | CA01 INSTALL AND TEST LUG AT SM 11 |
| 738 | SV3-SFS-MTW-ME2202 | INSTALLATION OF KB12 DEMINERALIZER TANKS (SFS-MV-01A & SFS-MV-01B) |
| 739 | SV3-CA01-S4W-CV2060 | FABRICATE LEAK CHASE PLUG BARS AND END CAPS SUBASSEMBLY 06 |
| 740 | SV3-WGS-P0W-ME2984 | Installation of WGS Piping in Module R151 Per ISO SV3-WGS-PLW-541 |
| 741 | SV3-SFS-PHW-ME7022 | FABRICATION/INSTALLATION OF CA03 CLASS D PIPE SUPPORTS SV3-SFS-PH-11R2024; SV3-SFS-PH-11R2025; & SV3-SFS-PH-11R2026 |
| 742 | SV3-WGS-P0W-ME2972 | FABRICATE AND INSTALL WGS PIPING FOR MODULE R161 (INCLUDES DRAWING SV3-WGS-PLW-540) |
| 743 | SV0-0000-SSW-CV7453 | MISCELLANEOUS STRUCTURAL STEEL |
| 744 | SV0-PWS-CCW-CV0415 | Pipe Support Level Foundations |
| 745 | SV3-CA01-V2W-CV2100 | CA01 INSTALL AND TEST LUG AT SM13 |
| 746 | SV3-WWS-P0W-ME2701 | WWS EMBEDED PIPING INSTALLATION (INCLUDING ISOMETRIC SV3-WWS-PLW-310, 31E, 319, & 31A) |
| 747 | SV4-KB16-KBW-ME7485 | INSTALLATION OF LIQUID SEAL HEAT EXCHANGER SV4-WLS-ME-03 |
| 748 | SV3-CA01-S4W-CV2241 | CA01-31 SUBMODULE ERECTION |
| 749 | SV3-CA01-S4W-CV2552 | INSTALLATION OF CA01-14 |
| 750 | SV3-CA01-V2W-CV2101 | CA01 Install and Test Lug at SM 16 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

**Table 2. Completed and Voided Work Packages (as of October 17, 2017)**

| | | |
|---|---|---|
| 751 | SV4-CWS-PLW-ME0198 | Unit 4 CWS Phase 1 Supply Line |
| 752 | SV0-PWS-PVW-862469 | DISASSEMBLE/TROUBLESHOOT, PWS VALVE #SV0-PWS-V591B, AND GEAR BOX |
| 753 | SV3-WLS-PLW-ME0903 | Fabricate and Install WLS Embedded Piping Iso SV3-WLS-PLW-562, 566, 573, 574, and 575 |
| 754 | SV4-WGS-PHW-861287 | INSTALLATION OF WGS PIPE SUPPORTS ON MODULE R155 |
| 755 | SV3-WLS-PLW-ME0904 | Fabricate and Install WLS Embedded Piping Iso SV3-WLS-PLW-564, 565, 570, 571, and 572 |
| 756 | SV0-RWS-PHW-861105 | FABRICATE AND INSTALL RWS SUPPORTS SV0-RWS-PH-00R0185 & SV0-RWS-PH-00R0189 @ BLDG 315 |
| 757 | SV0-RWS-EKW-EL0679 | Installation of Electric Load Centers and Misc. Equipment Commodities for the RWS and Tank Farm Pump House Switchgear Bldg. 315 |
| 758 | SV0-PWS-PHW-861991 | FABRICATE AND INSTALL THE PIPE SUPPORTS AND BASEPLATES ASSOCIATED WITH ISOMETRIC SV0-PWS-PLW-981 |
| 759 | SV0-RWS-PHW-ME8406 | Fabricate and Install the RWS Pipe Supports On the RWS Transfer Pumps |
| 760 | SV4-KB15-KBW-ME7476 | INSTALLATION OF KB15 COMPONENTS |
| 761 | SV4-FPS-PHW-861258 | INSTALLATION OF FPS PIPE SUPPORTS ON MODULE R151 |
| 762 | SV0-0000-CCW-CV1583 | Construction of Concrete Transformer Foundations and Other Appurtenant Concrete for the 300 Series Buildings |
| 763 | SV0-0000-CCW-860201 | MISCELLANEOUS CONCRETE FOUNDATIONS FOR THE 315 BUILDING |
| 764 | SV3-CA01-S4W-CV2206 | CA01 SM 02 INSTALLATION |
| 765 | SV3-CA01-S4W-CV2147 | CA01-9 Submodule Erection |
| 766 | SV3-1208-SCW-CV3034 | COURSE 2 UNIT 3 SHIELD BUILDING |
| 767 | SV4-KB16-KBW-ME7486 | INSTALLATION OF KB16 DEGASIFIER SEPARATOR PUMPS |
| 768 | SV3-CA01-S5W-CV4226 | CA01-38 UNSAT IRS AND N&DS- STRUCTURE REPAIRS |
| 769 | SV3-CA05-S4W-CV1877 | CA05 EMBED PLATES AND BEAM SEATS WEST SIDE |
| 770 | SV3-CA01-S4W-CV2081 | FABRICATE LEAK CHASE PLUG BARS AND WELD END CAPS FOR LEAK CHASE FOR CA01 SUB ASSEMBLY 5 |
| 771 | SV3-CA01-S5W-CV3319 | CA01-27 UNSAT IRS AND N&DS - STRUCTURE REPAIRS |
| 772 | SV3-CA01-S4W-CV2096 | CA01-33 SUBMODULE ERECTION |
| 773 | SV4-R161-MDW-861307 | INSTALLATION OF DUCTWORK AND SUPPORTS ON MODULE R161 |
| 774 | SV4-CAS-P0W-861276 | INSTALLATION OF CAS PIPING ON MODULE R155 |
| 775 | SV0-ZRS-EWW-EL3563 | 315 BLDG CBL PULLING & TERMINATIONS FOR ZRS SYSTEM |
| 776 | SV3-CA01-S4W-CV2226 | CA01 SM24 INSTALLATION |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 777 | SV3-KB11-KBW-ME2284 | FABRICATION OF KB11 MECHANICAL EQUIPMENT MODULE |
| 778 | SV4-R151-MDW-861269 | INSTALLATION OF HVAC DUCTWORK AND SUPPORTS ON MODULE R151 |
| 779 | SV3-CA01-S5W-CV2817 | CA01-47 REPAIR WORK |
| 780 | SV3-CA20-V2W-CV1728 | INSTALL CA20 LIFT LUGS 164 AND 165 |
| 781 | SV0-ZRS-MTW-ME8969 | Install Diesel Generator's Day Tank--SV0-ZRS-MT-002 @ Bldg 315 |
| 782 | SV4-FPS-P0W-861257 | INSTALLATION OF FPS PIPING ON MODULE R151 |
| 783 | SV4-PGS-PHW-861302 | INSTALLATION OF PGS PIPE SUPPORTS ON MODULE R161 |
| 784 | SV4-PGS-P0W-861282 | INSTALLATION OF PGS PIPING ON MODULE R155 |
| 785 | SV0-PWS-P0W-ME8001 | FABRICATE AND INSTALL THE PWS DISCHARGE PIPING FROM THE PWS PUMP SKID TO THE EXISTING UNDERGROUND PIPE FLANGE @ BLDG. 315 |
| 786 | SV4-CAS-PHW-861277 | INSTALLATION OF CAS PIPE SUPPORTS ON MODULE R155 |
| 787 | SV3-KB10-KBW-ME2469 | Fabrication/Installation of KB10/WWS sump pit and drain structure and pipe supports |
| 788 | SV4-PGS-PHW-861283 | INSTALLATION OF PGS PIPE SUPPORTS ON MODULE R155 |
| 789 | SV4-FPS-P0W-861280 | INSTALLATION FPS PIPING ON MODULE R155 |
| 790 | SV3-4032-CCW-CV1886 | Unit 3 Annex Area 2 East SUmp and Elevator Pit Installation |
| 791 | SV3-CA01-S4W-CV2377 | CA01-07-CORRECT UNSAT IR AND N&Ds |
| 792 | SV3-CA20-S4W-CV2210 | Unit 3 CA20 Coupler Installation at Weld Seams |
| 793 | SV3-EDS-DBW-EL3129 | INSTALL ANNEX BLDG EDS02-DB1 BATTERY RACKS, ROOM 40309 |
| 794 | SV4-0000-CRW-CV8074 | UNIT 4 TRANSFORMER REINFORCEMENT (PLACEMENT 2) |
| 795 | SV3-KQ11-KQW-ME0566 | Install Module KQ11 Portion 1 |
| 796 | SV4-FPS-PHW-861281 | INSTALLATION OF FPE PIPE SUPPORTS ON MODULE R155 |
| 797 | SV4-SDS-PLW-ME1266 | INSTALL SANITARY DRAIN LIFT STATION MS-500 |
| 798 | SV4-ML05-MLW-ME1746 | Attachment of Welded Nelson Studs to Embedded Piping Penetrations 66'-6"-82'-6" Walls Only |
| 799 | SV4-WGS-PHW-861266 | INSTALLATION OF PIPE SUPPORTS OF MODULE R151 |
| 800 | SV3-ME01-PLW-ME0913 | Condenser A Turbine Bypass Piping & Supports |
| 801 | SV4-KB04-KBW-ME5676 | Installation of Module KB04 |
| 802 | SV4-CA20-P0W-860236 | INSPECTION/ VERIFICATION OF CA20 EMBEDDED PIPING |
| 803 | SV3-CA03-S4W-CV2266 | CA03 INSTALL LIFTING LUGS FOR NI SET |
| 804 | SV4-0000-CRW-CV8076 | UNIT 4 TRANSFORMER REPLACEMENT (PLACEMENT 4) |
| 805 | SV4-WGS-PHW-861306 | INSTALLATION OF WGS PIPE SUPPORTS ON MODULE R161 |
| 806 | SV3-CA01-S4W-CV2064 | CA01-37 PRELIMINARY SUB-MODULE FIT-UP |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 807 | SV3-CA01-S5W-CV4213 | CA01-15, PERFORM STRUCTURAL N&D & INSPECTION REPORT (IR) S561-004-14-0467 REWORK AND REPAIRS |
| 808 | SV3-DWS-PHW-ME2979 | INSTALLATION OF DWS PIPING SUPPORTS IN MODULE R151 |
| 809 | SV4-WLS-P0W-ME5395 | INSTALLATION OF KB11 PIPING ISOMETRICS SV4-WLS-PLW-660 & -661 |
| 810 | SV3-1208-CCW-CV8997 | CONCRETE IN COURSE 3 SHIELD BUILDING PANELS |
| 811 | SV3-CA05-S5W-CV2230 | CA05-PAPERCLIP REBAR REMOVAL AND RE-INSTALLATION |
| 812 | SV3-CA05-S5W-CV1869 | CA05 WORK N&Ds FROM SUPPLIER |
| 813 | SV3-WLS-PLW-ME0683 | Fabricate and Install WLS Embedded Piping Iso SV3-WLS-PLW-755 |
| 814 | SV3-KB12-KBW-ME2258 | Installation of KB12 Structural Steel |
| 815 | SV3-RNS-P0W-861215 | REMOVE MODULE Q240 VALVE OPERATORS |
| 816 | SV3-KB10-KBW-ME2129 | INSTALLATION OF WWS PIPING - MODULE KB10 (ISOMETRICS: WWS-PLW-010, 011, 017, 01G) |
| 817 | SV3-ML05-MLW-850000 | INSTALLATION OF SV3-11206-ML-P01 PENETRATION |
| 818 | SV4-CAS-PHW-861268 | INSTALLATION OF CAS PIPE SUPPORTS ON MODULE R151 |
| 819 | SV0-PWS-PHW-ME0924 | INSTALL PIPE SUPPORTS ON THE POTABLE WATER LINES FOR BUILDING 315 |
| 820 | SV4-CCS-PHW-861298 | INSTALLATION OF CCS PIPE SUPPORTS ON MODULE R161 |
| 821 | SV4-VWS-P0W-861263 | INSTALLATION OF VWS-PIPING ON MODULE R151 |
| 822 | SV3-CA01-S5W-CV2082 | CA01-32 FABRICATION & ASSEMBLY |
| 823 | SV3-CA01-S4W-CV3799 | CA01-42 SUBMODULE INSTALLATION |
| 824 | SV4-VWS-PHW-861264 | INSTALLATION OF VWS PIPE SUPPORTS ON MODULE R151 |
| 825 | SV4-WGS-P0W-861286 | INSTALLATION OF WGS PIPING ON MODULE R155 |
| 826 | SV3-CA01-S4W-CV4145 | CA01-39 SUBMODULE ERECTION |
| 827 | SV3-WLS-PHW-ME2481 | FABRICATION/INSTALLATION OF KB11/WLS TUBING SUPPORTS(GR.35) |
| 828 | SV4-VWS-PHW-861304 | INSTALLATION OF VWS PIPE SUPPORTS ON MODULE R161 |
| 829 | SV4-CA20-S5W-CV4001 | CA20-01 UNSATISFACTORY IRs/N&Ds/E&DCRs AND LOOSE PARTS - STUDS |
| 830 | SV4-KB14-KBW-ME7083 | INSTALLATION OF THE KB14 MODULE |
| 831 | SV3-CA03-S4W-CV2261 | CA03 TOP WALKWAY SUPPORT STEEL |
| 832 | SV4-PGS-P0W-861301 | INSTALLATION OF PGS-PIPING ON MODULE R161 |
| 833 | SV4-KB14-KBW-ME8945 | KB14 STRUCTURAL FRAME REWORK |
| 834 | SV4-KQ11-KQW-ME1684 | INSTALL MECHANICAL EQUIPMENT MODULE KQ11 (MT-02) - PORTION 1 |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 835 | SV3-CA01-S5W-CV4221 | CA01-35 UNSAT IR'S AND N&D'S REWORK AND REPAIRS |
| 836 | SV4-CAS-P0W-861295 | INSTALLATION OF CAS PIPING ON MODULE R161 |
| 837 | SV3-KB10-KBW-ME2130 | INSTALLATION OF WWS PIPING - MODULE KB10 (ISOMETRICS: WWS-PLW-012, 013, 015, 016) |
| 838 | SV3-CA01-S5W-CV4148 | CA01-41 UNSAT IRs AND N&Ds - STRUCTURE REPAIRS |
| 839 | SV3-WLS-P0W-ME4603 | INSTALLATION OF WLS PIPING IN R216 MODULE |
| 840 | SV3-CA02-S5W-CV2564 | CA02-05 Unsatisfactory IRs and N&D Repairs - Structual Repairs |
| 841 | SV0-PWS-PVW-862794 | PULSATION DAMPENER 0-PWS-Y50A IS LEAKING AND NOT HOLDING AIR CHARGE ABOVE ZERO PSIG ON AIR SIDE OF DAMPENER |
| 842 | SV3-CA01-S5W-CV3042 | CA01-12 UNSAT IR AND N&D REPAIRS |
| 843 | SV3-CA20-S5W-CV1433 | Miscellaneous Rework for Closure of N&D's |
| 844 | SV4-WWS-PHW-ME5003 | Installation of Large Bore WWS Piping Supports (Includes Isometrics: SV4-WWS-PLW-31C, 31D, 313) |
| 845 | SV3-CA01-S5W-CV3308 | CA01-09 UNSATISFACTORY IRS AND N&D REPAIRS - STUDS |
| 846 | SV3-CA20-S5W-CV1904 | CA20-30 INSTALLATION OF ADDITIONAL REBAR COUPLERS AND REPLACEMENT OF REBAR COUPLERS RLREADY INSTALLED |
| 847 | SV0-0000-CCW-CV5528 | MISCELLANEOUS GROUTING IN 300 SERIES BUILDINGS/YARD |
| 848 | SV3-WLS-PHW-ME2222 | INSTALLATION OF PIPE SUPPORTS ON KB12 (FOR ISOMETRICS SV3-WLS-PLW-67X,68A) |
| 849 | SV3-VCS-MXW-CT8035 | U3 VCS Ductwork Coatings Rework |
| 850 | SV3-WLS-PHW-ME2219 | INSTALLATION OF PIPE SUPPORTS ON KB12 (FOR ISOMETRICS SV3-WLS-PLW-60C, 60N, 686) |
| 851 | SV0-0000-MEW-ME0715 | CONDENSER FABRICATION AREA PREPARATION (111 SATELLITE) |
| 852 | SV3-WLS-PHW-ME2368 | FABRICATION/INSTALLATION OF KB11/WLS PIPING SUPPORTS (SV3-WLS-PH-12R0443, 12R0450, 12R0459, 12R0466, 12R0478, 12R0777, 12R0778, 12R0779, 12R0781, & 12R0782) |
| 853 | SV3-CA03-S5W-CV2932 | CA03 REWORK UNSAT ITEMS- SUBMODULES 03 THRU 06 |
| 854 | SV3-CA20-S4W-CV0858 | Installation of CA20 SA1 EL. 107'-2" Floor Submodules (Submodules 52 & 53) |
| 855 | SV4-CA20-S4W-CV3262 | CA20-01 SUB-MODULE ERECTION |
| 856 | SV4-DWS-P0W-861259 | INSTALLATION OF DWS PIPING ON MODULE R151 |
| 857 | SV3-CA02-S4W-CV5779 | INSTALL CA02-03 PERMANENT WELDED ATTACHMENTS |
| 858 | SV4-CCS-P0W-861297 | INSTALLATION OF CCS PIPING ON MODULE R161 |
| 859 | SV3-VWS-P0W-ME2982 | Installation of VWS Piping in Module R151 Per ISO SV3-VWS-PLW-381, & 481 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 860 | SV3-WLS-PHW-ME2372 | FABRICATION/INSTALLATION OF KB11/WLS PIPING SUPPORTS (SV3-WLS-PH-12R0002, 12R0439, 12R0467, 12R0480, 12R0481, 12R0486, 12R0488, 12R0490, & 12R0491) |
| 861 | SV4-PGS-P0W-861261 | INSTALLATION OF PGS PIPING ON MODULE R151 |
| 862 | SV3-1000-CPW-CV5117 | CUTTING OF SOUTH SIDE UNIT 3 NUCLEAR ISLAND MSE WALL PANEL |
| 863 | SV3-CA03-S5W-CV2933 | CA03 RE-WORK UNSAT IR'S AND N&D FOR SUBMODULES 12 THRU 17 |
| 864 | SV0-CA01-SSW-CV4231 | CA01 PLATEN MODIFICATIONS FOR SUPPORT LEGS BELOW CA01-01 AND CA01-21 |
| 865 | SV3-2020-MEW-ME0845 | Attach Condenser A Upper Shell to Upper Tube Bundle RESERVED FOR Oran Poe |
| 866 | SV3-WLS-PHW-ME5371 | INSTALLATION OF WLS PIPE SUPPORTS IN R216 MODULE |
| 867 | SV0-YFS-JEW-863014 | DISSEMBLE/REMOVE/REPLACE WITH NEW, TRANSMITTER WSV0-YFS-JE-TT002A |
| 868 | SV0-ZRS-PVW-863155 | rOTATE SV0-ZRS-PL-V002 90 DEGREES (UP-RIGHT POSITION), BETWEEN PIPING FLANGES. |
| 869 | SV3-2030-M6W-ME1704 | INSTALL PIPING SUPPORTS FOR "A" TO "B" CONDENSER CROSSOVER PIPING |
| 870 | SV3-CA01-S4W-CV2228 | CA01 SM 22 INSTALLATION |
| 871 | SV4-4033-CRW-CV8103 | (BLANK) |
| 872 | SV3-2020-MEW-ME0739 | Install Condenser A Upper Shell Heater Truss |
| 873 | SV3-VCS-MXW-CT7413 | U3 CONTAINMENT BUILDING MD01 VCS DAMPERS COATINGS REWORK |
| 874 | SV3-CA03-S4W-CV2256 | CA03 SUBMODULE WALL ASSEMBLY (01, 02, 03) |
| 875 | SV3-CA20-S4W-CV0429 | Installation of CA20 SA2 EL 92'-6" Floor Submodules (Submods 43, 44, 45, 46) |
| 876 | SV3-ME01-PLW-ME1003 | Unit 3 Condenser A: Installation of MSR A&B Shell Drains |
| 877 | SV3-CA01-S4W-CV2551 | CA01-12 SUBMODULE INSTALLATION |
| 878 | SV3-CA20-V2W-CV1729 | INSTALL CA20 LIFT LUGS 166 AND 167 |
| 879 | SV3-CA01-S5W-CV3055 | CA01-12 UNSAT IR & N&D STUD REPAIRS |
| 880 | SV3-CA01-S4W-CV4277 | CA01-11 N&D APP-CA01-GNR-850354 REWORK |
| 881 | SV3-CA20-S4W-CV0423 | Installation of Subassembly 1 EL 82'-6" Floor Submodules |
| 882 | SV3-CA01-S5W-CV3309 | CA01-09 UNSATISFACTORY IRs AND N&D REPAIRS - STRUCTURAL REPAIRS |
| 883 | SV3-CA01-S4W-CV2079 | CA01-05 SUBMODULE ERECTION |
| 884 | SV3-R104-R1W-ME3033 | STRUCTURAL FABRICATION OF R104 MODULE |
| 885 | SV3-CA01-S5W-CV2270 | CA01-03 REPAIRS |
| 886 | SV3-KB15-KBW-ME2344 | INSTALLATION OF KB15 COMPONENTS |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 887 | SV4-DWS-PHW-861279 | INSTALLATION OF DWS PIPE SUPPORTS ON MODULE R155 |
| 888 | SV3-CA01-S4W-CV2238 | CA01-28 SUBMODULE ERECTION |
| 889 | SV4-WRS-PHW-861252 | INSTALLATION OF WRS PIPE SUPPORTS ON MODULE R104 |
| 890 | SV3-CA02-MHW-CV2561 | CA02 LIFTING FRAMES AND BRACING |
| 891 | SV3-CAS-P0W-ME2986 | INSTALLATION OF CAS PIPING IN MODULE R151 PER ISO SV3-CAS-P0W-421, & 321 |
| 892 | SV3-KB22-KBW-ME2203 | INSTALLATION OF KB22 COMPONENTS |
| 893 | SV3-2020-MEW-ME0852 | Install Condenser C Upper Shell to Upper Truss RESERVED FOR Oran Poe |
| 894 | SV4-CA20-CAW-850000 | CA20 MODULE INSTALLATION |
| 895 | SV3-PXS-PHW-ME7021 | FABRICATION/INSTALLATION OF CA03 CLASS E PIPE SUPPORT SV3-PXS-PH-11R0573 |
| 896 | SV3-MG20-MEW-ME4880 | Main Generator Sole Plate Installation |
| 897 | SV3-ML05-MLW-ME3413 | INSTALLATION OF CA03 PENETRATION |
| 898 | SV3-CA03-S4W-CV2265 | CA03 INSTALLATION OF LIFT LUGS (SUB-MODULE CA03-01 THRU CA03-17) |
| 899 | SV4-WLS-P0W-ME5400 | INSTALLATION OF KB11 PIPING ISOMETRIC SV4-WLS-PLW-683 |
| 900 | SV4-WLS-P0W-ME5397 | INSTALLATION OF KB11 PIPING ISOMETRIC SV4-WLS-PLW-67C |
| 901 | SV3-2030-M6W-ME1702 | INSTALL CWS CROSSOVER PIING FROM "A" TO "B" CONDENSER |
| 902 | SV3-CA20-S4W-CV2323 | CA20 SUB ASSEMBLY 1 WORK LIST ITEMS WB-W00054, WB-W00055, WB-W00077, WB-W00080, WB-W00081, WB-W00085 & WB-W00116 |
| 903 | SV4-0000-CRW-CV8073 | UNIT 4 TRANSFORMER REINFORCEMEN (PLACEMENT 1) |
| 904 | SV3-CA05-S4W-CV1875 | CA05 EAST SIDE WALL OVERLAY PLATES AND BEAM SEATS INSTALLATION |
| 905 | SV4-WLS-P0W-ME5398 | INSTALLATION OF KB11 PIPING ISOMETRICS SV4-WLS-PLW-67Q & -67S |
| 906 | SV4-WLS-P0W-ME5399 | INSTALLATION OF KB11 PIPING ISOMETRIC SV4-WLS-PLW-67W |
| 907 | SV3-KB20-KBW-ME1675 | Installation of Module KB20 (WLS Chemical Waste Pump) |
| 908 | SV3-WLS-P0W-ME2760 | KB16-Install Bore Separator Pump Suction Piping (Isometric SV3-WLS-PLW-120) |
| 909 | SV3-SFS-P0W-ME2132 | Installation of Large Bore KB12 SFS Piping (Including Isometrics SV3-SFS-PLW-60A, 60B) |
| 910 | SV3-WLS-P0W-ME2766 | KB16 - INSTALLATION OF SMALL BORE CONDENSER PIPING (ISOMETRICS SV3-WLS-PLW-102, 103, 104, 105, 106, & 107) |
| 911 | SV3-2020-MEW-ME0555 | Unit 3 Condenser A Hot Well Assembly |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 912 | SV0-RWS-PHW-ME9004 | FABRICATE AND INSTALL THE RAW WATER PIPE SUPPORTS ON ISOMETRIC SV0-RWS-PLW-500, 502, 512, 524, 525, 737 & 738 |
| 913 | SV0-RWS-PLW-ME0917 | Install Raw Water Lines for Building 315 |
| 914 | SV3-CA01-S5W-CV4211 | CA01-16 IR STRUCTURAL AND N&DS |
| 915 | SV4-2020-MEW-TP1407 | Unit 4 Condenser Upper Shell Construction Aid Support Platform |
| 916 | SV4-CA01-S5W-CV6458 | CA01-27 UNSAT IRs/N&Ds/E&DCRs/LOOSE PARTS - STRUCTURAL |
| 917 | SV3-2040-MLW-ME2937 | INSTALLATION OF EMBEDDED PIPING PENETRATION FLOOR SLEEVES (SLABS 1 AND 6). |
| 918 | SV3-PGS-PHW-ME2981 | INSTALLATION OF PGS PIPING SUPPORTS IN MODULE R151 |
| 919 | SV4-CA20-S5W-CV5294 | CA20-12 UNSATISFACTORY IRs/N&DS/E&DCRs AND LOOSE PARTS - STUDS |
| 920 | SV3-KB22-KBW-ME1667 | Installation of Module KB22-WLS Effluent Holdup Pump B |
| 921 | SV0-RWS-THW-ME8937 | PERFORM HYDROSTATIC TESTING ON THE RAW WATER LINES @ BUILDING 315 |
| 922 | SV4-CA20-S5W-CV5766 | CA20-72 UNSAT IR# & N&D STRUCTURAL REPAIRS |
| 923 | SV4-CA20-S5W-CV5285 | CA20-10 UNSAT IR, N&D AND SHIP LOOSE MATERIAL STRUCTURAL REPAIRS |
| 924 | SV3-1208-ITW-CV4392 | PRE-ITAAC MEASUREMENTS |
| 925 | SV4-WLS-P0W-ME5394 | INSTALLATION OF KB11 PIPING ISOMETRICS SV4-WLS-PLW-602, -603, -604, -605, -606, -607, -609, -60K, & -60L |
| 926 | SV3-CA20-S4W-CV2487 | CA20 SUB ASSEMBLY 3 WORK LIST ITEMS WB-W00019, WB-W00024, WB-W00025, WB-W00026, WB-W00027 & WB-W00028 |
| 927 | SV0-RWS-CWS-CV6291 | RAW WATER INTAKE FOUNDATION(S) |
| 928 | SV3-2030-M6W-ME1703 | INSTALL CWS CROSSOVER PIPING FROM "B" TO "C" CONDENSER |
| 929 | SV3-CA20-S4W-CV2609 | FABRICATION OF ADDITIONAL CA20 OVERLAY PLATES |
| 930 | SV3-WGS-THW-ME3037 | KB16-HYDROSTATIC TESTING OF WGS PIPING |
| 931 | SV3-CA01-S4W-CV2384 | CA01-08 SUBMODULE PRE-ASSEMBLY FABRICATION |
| 932 | SV0-PWS-THW-ME2702 | HYDRO TEST THE POTABLE WATER SYSTEM (PWS) AT BUILDING 315 |
| 933 | SV4-ML05-MLW-ME7941 | INSTALL CA01 PROCESS PIPE PENETRATIONS SV4-11501-ML-P03, SV4-11501-ML-P04, & SV4-11502-ML-P03 |
| 934 | SV3-CA05-S5W-CV1870 | MODIFY CA05-02 AND CA05-03 PER EDCR APP-CA05-GEF-068 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| | | |
|---|---|---|
| **Table 2. Completed and Voided Work Packages (as of October 17, 2017)** | | |
| 935 | SV3-1208-SCW-CV3078 | COURSE 1 UNIT 3 SHIELD BUILDING |
| 936 | SV3-CA03-S4W-CV2264 | CA03 FLOOR LEAK CHASE PLATES INSTALLATION |
| 937 | SV4-CA20-S5W-CV5771 | CA20-73 UNSAT IR# & N&D STRUCTURAL REPAIRS |
| 938 | SV3-2040-MLW-ME2939 | INSTALLATION OF EMBEDDED PIPING PENETRATION FLOOR SLEEVES (SLAB 2). |
| 939 | SV3-WLS-PHW-ME2369 | FABRICATION/INSTALLATION OF KB11/WLS PIPING SUPPORTS (SV3-WLS-PH-12R0006, 12R0453, 12R0457, 12R0460, 12R0464, 12R0470, 12R0475, & 12R0780) |
| 940 | SV4-VCS-MXW-CT7415 | U4 CONTAINMENT BUILDING MD01 VCS DAMPERS COATINGS REWORK |
| 941 | SV3-2030-M6W-ME1705 | INSTALL PIPING SUPPORTS FOR "B" TO "C" CONDENSER CROSSOVER PIPING |
| 942 | SV4-CA20-S4W-CV3267 | INSTALLATION OF SUBMODULE CA20-06 |
| 943 | SV3-R151-R1W-ME0724 | R151 COMMODITY MODULE INSTALLATION |
| 944 | SV3-WLS-P0W-ME2135 | INSTALLATION OF SMALL BORE KB12 WLS PIPING (INCLUDES ISOMETRICS SV3-WLS-PLW-60A, 60M & 608) |
| 945 | SV3-WRS-PHW-ME0781 | INSTALLATION OF LARGE BORE WRS PIPING SUPPORTS: SV3-WRS-PH-12A0807, 12R0083 |
| 946 | SV3-WLS-P0W-ME2767 | KB16 - INSTALLATION OF SMALL BORE VACUUM PUMP PIPING (ISOMETRIC SV3-WLS-PLW-090, 100, & 101 |
| 947 | SV3-2050-MLW-ME6296 | INSTALLATION OF MECHANICAL PIPE SLEEVES FOR SLAB(S) 4 ELEVATION 140' |
| 948 | SV4-ML05-MLW-ME4812 | Attachment of welded nelson studs to embedded piping penetrations 82'-6" Floors only" |
| 949 | SV3-CA01-S5W-CV4142 | CA01-34 UNSATISFACTORY IRs AND N&D REPAIRS - STUDS |
| 950 | SV4-WWS-P0W-ME1978 | WWS EMBEDDED PIPING INSTALLATION (INCLUDING ISOMETRIC SV3-WWS-PLW-31C, 31D, 31K, & 313) |
| 951 | SV4-SFS-P0W-ME5409 | INSTALLATION OF KB12 PIPING ISOMETRIC SV4-SFS-PLW-089 |
| 952 | SV4-4031-CCW-CV5068 | UNIT 4 ANNEX BUILDING AREA 1 ELEVATOR PIT |
| 953 | SV4-CA20-S5W-CV5761 | CA20-71 UNSAT IR# & N&D STRUCTURAL REPAIRS |
| 954 | SV4-VWS-PHW-ME7495 | INSTALLATION OF KB16 VWS PIPE SUPPORTS |
| 955 | SV4-CA20-V2W-CV7511 | INSTALL SUPER LIFT LUG AT CA20-01 |
| 956 | SV4-WGS-P0W-ME2014 | INSTALLATION OF SMALL BORE WGS PIPING (INCLUDES SV4-WGS-PLW-050, 101, 103, 105, 107) |
| 957 | SV3-WLS-P0W-ME2137 | INSTALLATION OF SMALL BORE KB12 WLS PIPING (INCLUDES ISOMETRICS SV3-WLS-PLW-60B, 60H & 60J) |
| 958 | SV3-WLS-PHW-ME2371 | FABRICATION/INSTALLATION OF KB11/WLS PIPING SUPPORTS (SV3-WLS-PH-12R0445, 12R0705, 12R0438, 12R0446, 12R0783, 12R0700, 12R0440, 12R0001, 12R0452, 12R0474) |
| 959 | SV3-VAS-MDW-ME2975 | R155 MODULE HVAC AC COMPLETION |
| 960 | SV4-CA20-S4W-CV3263 | CA20-02 SUB-MODULE ERECTION |
| 961 | SV3-FPS-P0W-ME2976 | INSTALLATION OF FPS PIPING IN MODULE R151 PER ISO SV3-FPS-PLW-721 |
| 962 | SV0-0000-XGW-CV0447 | RWI Site Development |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 963 | SV3-WLS-P0W-ME2138 | INSTALLATION OF SMALL BORE KB12 WLS PIPING (INCLUDES ISOMETRICS SV3-WLS-PLW-60D & 672) |
| 964 | SV3-R155-R1W-ME0725 | INSTALLATION OF R155 COMMODITY MODULE |
| 965 | SV3-PGS-P0W-ME2980 | INSTALLATION OF PGS PIPING IN MODULE R151 PER ISO SV3-PGS-PLW-121 |
| 966 | SV4-R104-MDW-861253 | INSTALLATION OF HVAC DUCTWORK AND SUPPORTS ON MODULE R104 |
| 967 | SV4-CB65-S5W-CV4419 | INSTALL COUPLERS ON SV4 CB65 OLP's |
| 968 | SV3-CAS-PHW-ME2987 | INSTALLATION OF CAS PIPING SUPPORTS IN MODULE R151 |
| 969 | SV3-CA02-S5W-CV5943 | CA02-03 STRUCTURAL UNSAT IR'S AND N&D'S |
| 970 | SV3-VWS-PHW-ME2983 | Installation of VWS Piping Supports in Module R151 |
| 971 | SV4-WGS-P0W-ME6122 | INSTALL KB04 WGS PIPING |
| 972 | SV3-CA20-S4W-CV2324 | CA20 SUB ASSEMBLY 1 PUNCH LIST ITEMS WB-W00029, WB-W00067, WB-W00075, & WB-W00093 |
| 973 | SV3-WLS-PHW-ME0841 | Installation of Small Bore WLS Piping Supports for Isometric SV#-WLS-PLW-33D |
| 974 | SV3-CA03-SUW-CV7094 | CA03 - PROCEDURES AND SPECIFICATIONS BOOK |
| 975 | SV4-WLS-MVW-ME5402 | INSTALLATION OF KB11/WLS MECHANICAL EQUIPMENT |
| 976 | SV3-CA01-S4W-CV0400 | CA01 SM 01 INSTALLATION |
| 977 | SV3-CA05-S4W-CV1876 | CA05 EMBED PLATES AND BEAM SEATS SOUTH SIDE |
| 978 | SV3-CA20-S4W-CV1386 | Pre-Assembly of CA20 Floor Submodules (CA20-43, 44, 45, 46, 47, 48, 49, 50, 56, 57) |
| 979 | SV3-CA20-S4W-CV0433 | CA20 WALL J2 OVERLAY PLATES INSTALLATION |
| 980 | SV3-VAS-MDW-ME2988 | INSTALLATION OF VAS HVAC DUCT IN MODULE R151 |
| 981 | SV4-CA01-S4W-CV6408 | CA01-14-SUB MODULE INSTALLATION |
| 982 | SV4-CA20-S5W-CV4010 | UNSAT IR# & N&D STRUCTURAL REPAIRS, |
| 983 | SV3-1208-SCW-CV4914 | COURSE 5 UNIT 3 SHIELD BUILDING |
| 984 | SV3-2040-MLW-ME2940 | INSTALLATION OF EMBEDDED PIPING PENETRATION FLOOR SLEEVES (SLABS 4 AND 5). |
| 985 | SV3-2060-MLW-ME8897 | FABRICATION AND INSTALLATION OF MECHANICAL PIPING PENETRATIONS EL. 196' |
| 986 | SV3-2060-MLW-ME8896 | FABRICATION AND INSTALLATION OF MECHANICAL PIPING PENETRATIONS FOR SLABS 1&2 ON ELEVATION 170' |
| 987 | SV3-2060-MLW-ME8895 | INSTALLATION OF MECHANICAL PIPE SLEEVES FOR SLAB(S) 5 & 6 ELEVATION 170' |
| 988 | SV4-SFS-MVW-ME5417 | INSTALLATION OF KB12/SFS MECHANICAL EQUIPMENT |
| 989 | SV4-ML05-MLW-ME4810 | ATTACHMENT OF WELDED COUPLINGS 82'-6" FLOOR PENETRATIONS |
| 990 | SV0-8100-EWW-TP1212 | Temporary Power For Bldg. 203 Westinghouse Field Offices |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 991 | SV0-852-EWW-TP0407 | Power to Icehouse (144) and Well 3 |
| 992 | SV0-0000-CCW-CV0008 | Installation of the Module Assembly Building Foundation |
| 993 | VNC-COMM-ZRS-001 | Electrical Phase 2 and Fiber Optic |
| 994 | SV3-FPS-THW-ME3421 | HYDRO TESTING OF FPS PIPING IN MODULE R151 - ISO SV3-FPS-PLW-721 |
| 995 | SV3-PGS-THW-ME3423 | HYDRO TESTING OF PGS PIPING IN MODULW R151-IS0 SV3-PGS-PLW-121 |
| 996 | SV3-VWS-THW-ME3424 | HYDRO TESTING OF VWS PIPING IN MODULE R151-ISO SV3-VWS-PLW-381, & 481 |
| 997 | SV3-WGS-THW-ME3425 | HYDRO TESTING OF WGS PIPING IN MODULE R151 - ISO SV3-WGS-PLW-541 |
| 998 | SV0-PWS-PPW-ME0257 | Start-Up for the Temporary Potable Water Solution and Disinfect of PWS Header and Building 120 |
| 999 | SV4-CA01-S4W-CV6521 | CA01-46 SUB MODULE INSTALLATION |
| 1000 | SV4-CA20-S5W-860207 | CA20 FABRICATION OF BULK FLAT BAR |
| 1001 | SV3-WLS-PHW-ME2367 | FABRICATION/INSTALLATION OF KB11/WLS PIPING SUPPORTS (SV3-WLS-PH-12R0444, 12R0447, 12R0451, 12R0454, 12R0458, 12R0461, 12R0465, 12R0468, 12R0471, & 12R9025) |
| 1002 | SV3-CA20-S4W-CV0310 | CA20 SA2 Wall Submodule Erection (10, 11, 12, 13, 14, 15, 16, 17) |
| 1003 | SV4-CB65-S4W-CV2568 | UNIT 4 CB65 ASSEMBLY |
| 1004 | SV3-CA20-S4W-CV0441 | CA20 WALL L2 OVERLAY PLATES INSTALLATION |
| 1005 | SV3-WLS-P0W-ME2143 | INSTALLATION OF SMALL BORE KB11 WLS PIPING (INCLUDING SV3-WLS-PLW-678, 679, 67D, 67E, 67G, 67H, 67L, 67N, 682, & 688) |
| 1006 | SV3-WLS-P0W-ME2145 | Installation of Small Bore KB11 WLS Piping(Including SV3-WLS-PLW-67C, 67F, 67P, 67Q, 67S, 67W, 683, & 68D) |
| 1007 | SV3-CA01-S5W-CV2351 | CA01-01 REPAIR WORK |
| 1008 | SV3-CA01-S4W-CV2095 | INSTALLATION OF CA01-32. |
| 1009 | SV3-SFS-PHW-ME2218 | INSTALLATION OF PIPE SUPPORTS ON KB12 (FOR ISOMETRICS SV3-SFS-PLW-60A, 60B) |
| 1010 | SV3-CA01-S5W-CV2327 | Finish Fabrication and Perform Work per Miscellaneous N&Ds |
| 1011 | SV4-DWS-PHW-861260 | INSTALLATION OF DWS PIPE SUPPORTS ON MODULE R151 |
| 1012 | SV3-WLS-PHW-ME2220 | INSTALLATION OF PIPE SUPPORTS ON KB12 (FOR ISOMETRICS SV3-WLS-PLW-60E, 60F, 60G) |
| 1013 | SV0-8400-EWW-EL0061 | Electrical Service to the Sign Shop |
| 1014 | SV0-874-EWW-TP0702 | Control Power Installation For Sprinkler System at Batch Plant |
| 1015 | SV3-WLS-P0W-ME2142 | INSTALLATION OF SMALL BORE KB11 WLS PIPING (INCLUDING SV3-WLS-PLW-602, 603, 604, 605, 606, 607, 609, 60K, & 60L) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1016 | SV4-ML05-MLW-ME1742 | INSTALLATION OF EMBEDDED PIPING PENETRATIONS 66'-6"-82'-6" WALLS ONLY |
| 1017 | SV3-CA01-S5W-CV3318 | CA01-27 UNSATISFACTORY IRs AND N&D REPAIRS-STUDS |
| 1018 | SV3-WLS-PHW-ME2370 | FABRICATION/INSTALLATION OF KB11/WLS PIPING SUPPORTS (SV3-WLS-PH-12R0479, 12R0489, 12R0487, 12R0485, 12R0482, 12R0437, 12R0484, & 12R0483) |
| 1019 | SV3-2050-MLW-ME6295 | INSTALLATION OF MECHANICAL PIPE SLEEVES FOR SLAB(S) 1 ELEVATION 140' |
| 1020 | SV3-CA01-S5W-CV4143 | CA01-34 UNSAT STRUCT IR AND N&D'S |
| 1021 | SV3-KB37-KBW-ME2345 | INSTALLATION OF KB37 COMPONENTS |
| 1022 | SV3-CA01-S4W-CV2550 | CA01-11 SUBMODULE INSTALLATION |
| 1023 | SV4-2050-CRW-CV5852 | NS 141'-3" ELEV. REBAR POUR 2 |
| 1024 | SV4-CA20-S4W-CV3265 | CA20-04 SUB-MODULE ERECTION, |
| 1025 | SV4-CA20-S4W-CV5623 | CA20-24 UPENDING/SUB-MODULE INSTALLATION |
| 1026 | SV0-ZRS-ECW-863146 | REPLACE SIMOCODE PRO V |
| 1027 | SV3-CA01-S5W-CV3324 | CA01-13 UNSAT IR & N&D STUD REPAIRS |
| 1028 | SV0-SDS-PLW-ME0240 | Installation of All Remaining Grinder Pump Stations |
| 1029 | SV3-CA01-S4W-CV2059 | CA01-04 INSTALLATION |
| 1030 | SV0-891-EWW-EL0318 | Electrical Power Installation to Test Lab |
| 1031 | SV0-848-CCW-CV0177 | Area 158 Carpenter Pad Assembly |
| 1032 | SV0-842-CCW-CV0083 | Install Foundation for Mechanical/ Structural Fab Shop (Bldg. 131) |
| 1033 | SV0-ZRS-EWW-TP0540 | Installation of 13.8 KV line from Switchgear #5 to 3 way junction Northeast of Nuclear Island |
| 1034 | SV0-805-CCW-CV0078 | Install Foundation for Mechanical Shop (Bldg. 136) |
| 1035 | SV0-ME71-CCW-CV0626 | Fabrication of End Wall Plates |
| 1036 | SV0-842-EWW-EL0173 | Installation of Electrical Power to Mechanical Fab Shop (Building 131) |
| 1037 | SV0-812-EWW-EL0270 | Electrical Feeder Installation to New Hire Office (Bldg 118.) |
| 1038 | SV4-12171-CYW-800000 | Room 12171 Grout, WLS Waste Effluent Holdup Tank A (WLS-MT-05A) |
| 1039 | SV4-KB15-KBW-ME5677 | INSTALLATION OF MODULE KB15 (DEGASIFIER DISCHARGE PUMP) |
| 1040 | SV3-2050-MLW-ME6294 | INSTALLATION OF MECHANICAL PIPE SLEEVES FOR SLAB(S) 2 & 3 ELEVATION 140' |
| 1041 | SV3-VAS-MHW-ME2989 | INSTALLATION OF STRUCTURAL FRAMES AROUND HVAC DUCT IN MODULE R151 |
| 1042 | SV0-842-PPW-ME0210 | Fabrication and Installation of the Tempoary Piping PWS & SDS (above slab) and Fixtures for the Piping Fitting Shop, Building 131 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1043 | SV0-YFS-CCW-CV0005 | Install Yard Fire System (YFS) Diesel Pumphouse Building Foundation |
| 1044 | SV0-ZRS-EWW-EL0243 | Installation of 1000 kVA transformer and ZRS tie-into the north loop |
| 1045 | SV3-CA20-S4W-CV2166 | CA20 SUB ASSEMBLY 1 PUNCH LIST ITEMS WB-W00042, WB-W00057, WB-W00058, WB-W00060, WB-W00073, WB-W000872, WB-W00084, WB-W00087 |
| 1046 | SV3-CA20-MHW-CV1388 | Installation of Submodule CA20-26,27,28,29,30,71,72,73 Vertical Lifting Attachments |
| 1047 | SV0-MH90-MHW-RI0558 | Assembly of the HLD Boom and Mast |
| 1048 | SV3-KB27-KBW-ME1665 | INSTALLATION OF KB27 MECHANICAL MODULE |
| 1049 | SV4-SFS-P0W-ME5410 | INSTALLATION OF KB12 PIPING ISOMETRIC SV4-SFS-PLW-60A |
| 1050 | SV4-CA05-S4W-CV7028 | CA05-04 Temporary Attachments |
| 1051 | SV3-KB28-KBW-ME1666 | INSTALLATION OF MODULE KB28-WLS WASTE HOLDUP PUMP B |
| 1052 | SV3-2060-MLW-ME8894 | INSTALLATION OF MECHANICAL PIPE PENETRATIONS ELEVATION 170' SLAB(S) 3 & 4 |
| 1053 | SV4-KB04-MXW-CT7675 | COATINGS - U4 KB04 MODULE |
| 1054 | SV3-KB28-KBW-ME2205 | INSTALLATION OF KB28 COMPONENTS |
| 1055 | SV0-039-CCW-CV0309 | Installation of Foundation for Gas Storage Modules Bldgs 131 and 150 |
| 1056 | SV0-829-CCW-CV0179 | Area 111 CH80 and CH82 Module Fabrication Pads |
| 1057 | SV4-CA20-S5W-CV5615 | CA20-23 UNSAT IR - STUDS & LOOSE PARTS, |
| 1058 | SV0-MH90-CCW-CV0142 | Installation of the Heavy Lift Derrick Counterweight and Ring Foundation |
| 1059 | SV3-ME71-CCW-CV0320 | Installation fo the Hot Water Inlet Tunnel (Unit 3) |
| 1060 | SV0-PWS-PLW-ME0916 | Install Potable Water LInes for Building 315 |
| 1061 | SV3-CA03-S4W-CV2263 | CA03 WALL LEAK CHASE ASSEMBLY |
| 1062 | SV3-2020-MEW-ME0732 | Install Condenser A Lower Tube Bundle |
| 1063 | SV3-ME01-MEW-ME1290 | Condensers A,B & C: Addition of Omitted Welds on Upper Shell Baffle Plates and Turbine Bypass Piping |
| 1064 | SV4-12172-CYW-800000 | Room 12172 Grout, WLS Waste Effluent Holdup Tank B (WLS-MT-05B) |
| 1065 | SV4-CA20-S4W-CV3269 | CA20-08 SUB-MODULE ERECTION |
| 1066 | SV3-CA01-S5W-CV2496 | CA01-20 & CA01-21 INSTALLATION OF PAPER CLIP REBARS PER N&D AND E&DCR'S |
| 1067 | SV3-CA02-S5W-CV5573 | CA02-02-UNSAT IRS AND N&Ds - STUDS |
| 1068 | SV3-WLS-PLW-ME0892 | Fabricate and Install WLS Embedded Piping ISO SV3-WLS-PLW-642, 643, 644, 645, and 646 |
| 1069 | SV3-CA01-S4W-CV2065 | SUBMODULE CA01-25, CA01-47, AND CA01-48 ERECTION |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1070 | SV3-WLS-PLW-ME0902 | Fabricate and Install WLS Embedded Piping Iso SV3-WLS-PLW-577, 578 |
| 1071 | SV4-2020-SSW-CV1824 | TURBINE BUILDING CONDENSERS TEMPORARY HYDRO SUPPORT |
| 1072 | SV0-RWS-PVW-863439 | TROUBLESHOOT/REPLACE LEAKING PIPING FLANGE GASKET ON SV0-RWS-PL-V027A |
| 1073 | SV4-CA20-V2W-CV7510 | INSTALL SUPER LIFT LUG AT CA20-04/05 |
| 1074 | SV3-CA01-S5W-CV2277 | CA01-22 FABRICATION COMPLETION |
| 1075 | SV4-CA20-S4W-CV5628 | INSTALLATION OF SUB-MODULE CA20-25 |
| 1076 | SV4-CA20-S4W-CV5738 | INSTALLATION OF SUB-MODULE CA20-26 |
| 1077 | SV3-MV50-MLW-850000 | CONTAINMENT VESSEL-FUEL TRANSFER TUBE: INSTALLATION OF GUARD PIPE ANNULAR RING |
| 1078 | SV3-WLS-PLW-ME0887 | Fabricate and Install WLS Embedded Piping Iso SV3-WLS-PLW-647, 648, 649, and 64A |
| 1079 | SV3-CA01-S5W-CV2832 | CA01-29 UNSAT AND N&D REWORK |
| 1080 | SV4-WLS-PHW-ME5401 | INSTALLATION OF KB11 PIPE STRAPS |
| 1081 | SV4-CA01-S5W-CV6535 | SA3 LEAK CHASE FABRICATION |
| 1082 | SV3-CA02-S5W-CV6055 | SUBMODULE CA02-03 STUD UNSAT IR AND N&D REPAIR |
| 1083 | SV4-WLS-PHW-ME7489 | INSTALLATION OF KB16 WLS PIPE SUPPORTS |
| 1084 | SV3-CA01-S4W-CV2146 | CA01-08 SUBMODULE ERECTION |
| 1085 | SV3-R161-KBW-ME3696 | SITE COMPLETION OF R161 STRUCTURAL STEEL |
| 1086 | SV4-1208-SCW-CV6994 | COURSE 1 UNIT 4 SHIELD BUILDING |
| 1087 | SV4-WLS-P0W-ME5396 | INSTALLATION OF KB11 PIPING ISOMETRICS SV4-WLS-PLW-676, -678, -679, -67D, -67E, -67F, -67G, -67H, -67K, -67L, -67N, -67P, -67U, -682, -684, -685, -687, -688, -68D, & -68E |
| 1088 | SV3-CA01-S5W-CV2091 | CA01-32 UNSAT IR AND N&D REPAIRS |
| 1089 | SV4-CA20-V2W-CV7512 | INSTALL SUPER LIFT LUG AT CA20-13/14 |
| 1090 | SV4-SFS-PHW-ME5416 | INSTALLATION OF KB12 PIPE STRAPS |
| 1091 | SV3-CA03-S4W-CV2254 | CA03 SUBMODULE WALL ASSEMBLY (03, 04, 05, 06, 07) |
| 1092 | SV3-CA03-S4W-CV2255 | CA03 SUBMODULE WALL ASSEMBLY (11, 12, 13, 14, 15) |
| 1093 | SV3-CA01-S5W-CV3225 | CA01-31 SUBMODULE ASSEMBLY |
| 1094 | SV3-CA01-S5W-CV4141 | CA01-30 Unstatisfactory IRs and N&D Repairs - Studs |
| 1095 | SV3-CA01-S5W-CV3305 | CA01 SM 11 N&D AND INSPECTION REPORT STUD REWORK |
| 1096 | SV3-2020-MEW-ME0738 | UNIT 3 CONDENSER A UPPER SHELL EXTERIOR SHELL ASSEMBLY |
| 1097 | SV3-CA01-S5W-CV4210 | PERFORM N&D REWORK AND REPAIRS PER (IR) S540-001-14-0066 |
| 1098 | SV3-1208-SCW-CV4387 | COURSE 4 UNIT 3 SHIELD BUILDING |
| 1099 | SV3-CA20-S4W-CV0427 | CA20 Wall J1 Overlay Plates Installation |
| 1100 | SV0-8100-EWW-EL0060 | Temporary Power to Construction Office Trailers (Bldg:150 & Bldg:120) |
| 1101 | VNC-CFA-ME-PWS-004 | Potable Water System Installation |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1102 | VNC-EL861-EL-MSC-006 | New Security Entrance Roadway Lighting. |
| 1103 | VNC-EW87-EL-MSC-005 | Electrical Service to the Concrete Batch Plant |
| 1104 | VNC-CFA-ME-CAS-006 | Fabrication and Installation of Compressed Air System in NOI 7 |
| 1105 | SV0-8000-EWW-TP0636 | Electirical Power FEED to FFD Complex |
| 1106 | SV0-MH90-EWW-TP0668 | Installation of Electrical Power Feeder to HLD |
| 1107 | SV0-832-PLW-TP0546 | Install Praxair Bulk Storage Tanks & Associated Piping |
| 1108 | SV3-RNS-PVW-862966 | RE4-INSTALLATION OF Q240 VALVE ACTUATORS |
| 1109 | SV3-WLS-THW-ME3951 | HYDRO TESTING OF KB28 MODULE WLS PIPING |
| 1110 | SV0-853-PPW-ME0115 | Construction Craft Change House #2 below slab and embedded piping |
| 1111 | SV3-CA01-S4W-CV0549 | CA01 SM 03 INSTALLATION |
| 1112 | SV4-DWS-PHW-ME7498 | INSTALLATION OF KB16 DWS PIPE SUPPORTS |
| 1113 | SV4-RWS-JEW-863156 | REPLACE LEVEL TRANSMITTER SV4-RWS-JE-LT007B |
| 1114 | SV4-WRS-P0W-ME5337 | FABRICATION/INSTALLATION OF SMALL BORE WRS LEAK CHASE PIPING INCLUDING SV4-WRS-PLW-80L |
| 1115 | SV0-SDS-PLW-ME0039 | Trench #4 Sanitary Drainage System |
| 1116 | SV0-RWS-PLW-ME0072 | RWS- Tank Area Installation- Balance of Plant Components Supporting Temporary Supply |
| 1117 | SV3-WLS-PHW-ME2764 | KB16 - INSTALLATION OF PIPE SUPPORTS |
| 1118 | SV4-CA01-S5W-CV6368 | CA01-04 UNSATISFACTORY IRs/N&Ds/E&DCRs AND LOOSE PARTS - STUDS |
| 1119 | SV3-CA01-S5W-CV4149 | CA01-46 UNSATISFACTORY IRS AND N&DS REPAIR - STUDS |
| 1120 | SV3-CA02-S8W-CV2566 | INSTALL LIFTING LUGS FOR NI SET |
| 1121 | SV4-CA20-S5W-CV4013 | UNSAT IR# & N&D STUD REPAIRS, |
| 1122 | SV3-2050-MLW-ME6297 | INSTALLATION OF MECHANICAL PIPE SLEEVES FOR SLAB(S) 5 & 6 ELEVATION 140' |
| 1123 | SV4-CA20-S5W-CV4009 | UNSAT IR# & N&D STUD REPAIRS, |
| 1124 | SV4-CA20-S5W-CV4005 | CA20-02 UNSAT IR# & N&D STUD REPAIRS |
| 1125 | SV3-2020-MEW-ME0848 | Install Condenser B Upper Shell to Upper Truss |
| 1126 | SV3-ML05-MLW-ME4605 | INSTALLATION OF CA02/CA05 PENETRATION SV3-11305-ML-P01 |
| 1127 | SV3-2050-MLW-ME6298 | INSTALLATION OF MECHANICAL PIPE SLEEVES FOR SLAB(S) 7A & 7B ELEVATION 156' |
| 1128 | SV4-CA01-S5W-CV6537 | SA5 LEAK CHASE FABRICATION |
| 1129 | SV4-CA20-S4W-CV3264 | CA20-03 SUB-MODULE ERECTION |
| 1130 | SV3-WGS-PHW-ME2833 | FABRICATION/INSTALLATION OF KB14 WGS PIPING SUPPORTS |
| 1131 | SV3-EDS-DBW-EL3130 | INSTALL ANNEX BLDG EDS4-DB1 BATTERY RACKS, ROOM 40309 |
| 1132 | SV4-CA01-S4W-CV6412 | CA01-15 SUBMODULE INSTALLATION |
| 1133 | SV0-ZRS-JCW-862066 | MAIN PANEL #SV0-ZRS-JD-MCP001 |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 2. Completed and Voided Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1134 | SV3-KB13-KBW-ME2465 | INSTALLATION OF STRUCTURAL STEEL PIPE AND INSTRUMENT SUPPORTS AND LIFTING LUGS ON KB13 SUMP COVER |
| 1135 | SV3-2030-CEW-CV0131 | Unit 3 Turbine Building Construction Aides for EL. 100'-0" |
| 1136 | SV4-CA01-S5W-CV6534 | SA2 LEAK CHASE FABRICATION |
| 1137 | SV3-VWS-THW-ME3036 | KB16-HYDROSTATIC TESTING OF VWS PIPING |
| 1138 | SV3-CA20-S4W-CV2293 | REMOVAL OF CA20 LIFTING LUGS 164 AND 165 |
| 1139 | SV3-CA01-S5W-CV3335 | CA01 SUBASSEMBLY 02 LEAK CHASE FABRICATION |
| 1140 | SV3-CA01-S4W-CV2555 | CA01-17 SUBMODULE ERECTION |
| 1141 | SV3-CA01-S5W-CV3312 | CA01-06 UNSAT IR & N&D STRUCTURE REPAIRS |
| 1142 | SV4-CA20-S4W-CV5292 | INSTALLATION OF SUB MODULE CA20-11 |
| 1143 | SV4-CA01-S4W-CV6420 | SUBMODULE CA01-17 INSTALLATION |
| 1144 | SV4-WGS-THW-ME6274 | HYDRO TESTING OF KB04 WGS PIPING |
| 1145 | SV3-WLS-THW-ME4482 | HYDRO TESTING OF KB37 MODULE WLS PIPING (CLASSE E) |
| 1146 | SV0-SDS-PLW-ME0143 | Installation of Trench 6 Grinder Pumps, Lift Stations, and Manholes |
| 1147 | SV0-835-EWW-EL0167 | Electrical Installation for Tool Room, M&TE, Rigging Loft (Bldg 143) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| **No.** | **Work Package Number** | **Title** |
| 1 | SV3-RNS-P0W-ME0539 | INSTALLATION OF RNS LARGE BORE PIPING (INCLUDES ISOMETRIC SV3-RNS-PLW-211) |
| 2 | SV3-PGS-PHW-ME0798 | FABRICATION/INSTALLATION OF PGS PIPE SUPPORTS (ISO SV3-PGS-PLW-124, 129) |
| 3 | SV3-CAS-PHW-ME0789 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWINGS (SV3-CAS-PLW-330) |
| 4 | SV3-CAS-PLW-ME0457 | INSTALLATION OF SMALL BORE CAS PIPING (INCLUDES ISOMETRICS: SV3-CAS-PLW-375, 424, 42A, & 42B) |
| 5 | SV3-2070-SUW-CV0195 | TURBINE BUILDING STRUCTURAL STEEL FRAMING SEQUENCE 14 |
| 6 | SV3-2070-SUW-CV0197 | TURBINE BUILDING STRUCTURAL STEEL FRAMING SEQUENCE 16 |
| 7 | SV3-CAS-PLW-ME0459 | INSTALLATION OF SMALL BORE CAS PIPING ( INCLUDES ISOMETRICS: SV3-CAS-PLW-330 ) |
| 8 | SV3-VWS-PHW-ME0814 | INSTALLATION OF SMALL BORE VWS PIPING SUPPORTS FROM ISOMETRIC SV3-VWS-PLW-386 AND SV3-VWS-PLW-486. |
| 9 | SV3-DWS-PHW-ME0785 | FABRICATION/INSTALLATION OF DWS PIPE SUPPORTS (ISO SV3-DWS-PLW-60D, 624, 625) |
| 10 | SV3-DWS-PHW-ME0786 | FABRICATION/INSTALLATION OF DWS PIPE SUPPORTS (ISO SV3-DWS-PLW-627) |
| 11 | SV3-2060-SUW-CV0194 | Turbine Building Structural Steel Framing Sequence 13 |
| 12 | SV3-WLS-PHW-ME0773 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWINGS WLS-PLW-230, -390, -460, -710 |
| 13 | SV3-WLS-PHW-ME1038 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING WLS-PLW-041 |
| 14 | SV4-ME01-PLW-ME1016 | UNIT 4 CONDENSER A: INSTALLATION OF CASING DRAIN PIPING |
| 15 | SV4-ME01-PLW-ME1008 | UNIT 4 CONDENSERS C: INSTALLATION OF UPPER SHELL NOZZLES |
| 16 | SV4-ME01-PLW-ME1014 | Unit 4 Condenser A: Installation of Water Curtain Spray Piping |
| 17 | SV4-ME01-PLW-ME1025 | Condenser A: Installation of Vacuum Piping |
| 18 | SV4-ME01-PLW-ME1452 | Unit 4 Condenser B: Fabrication & Installation of Casing Drain Piping |
| 19 | SV4-ME01-PLW-ME1453 | UNIT 4 CONDENSER C: FABRICATION & INSTALLATION OF CASING DRAIN PIPING |
| 20 | SV3-ME3C-MEW-ME1461 | INSTALLATION OF TCS HEAT EXCHANGERS (TCS-ME-01A, -01B, & -01C) |
| 21 | SV3-ASS-PHW-ME1522 | Fabricate/Install of Auxiliary Steam (ASS) Supports (Portion 3) for Isometric # SV3-ASS-PLW-02H,022,02S, & 02E |
| 22 | SV4-ME01-PLW-ME1539 | UNIT 4 CONDENSER B: INSTALLATION OF WATER CURTAIN SPRAY PIPING |
| 23 | SV4-ME01-PLW-ME1540 | UNIT 4 CONDENSER C: INSTALLATION OF WATER CURTAIN SPRAY PIPING |
| 24 | VN3-XC10-CV-MSC-019 | Unit 3 Backfill from Elevation 180 feet to Grade |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 25 | SV3-DOS-P0W-ME2470 | FABRICATE AND INSTALL DIESEL FUEL OIL PIPING UNDER THE DIESEL BUILDING SLAB |
| 26 | SV3-CDS-PLW-ME2308 | INSTALLATION OF CDS PIPING FOR ISOMETRIC SV3-CDS-PLW-71A, SV3-CDS-PLW-711, SV3-CDS-PLW-712, SV3-CDS-PLW-713, SV3-CDS-PLW-714,SV3-CDS-PLW-715, SV3-CDS-PLW-716, |
| 27 | SV3-VWS-PLW-ME2794 | INSTALLATION OF VWS PIPING FOR ISOMETRICS SV3-VWS-PLW-10N, SV3-VWS-PLW-10P, SV3-VWS-PLW-10Q. |
| 28 | SV3-DWS-PHW-ME3096 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-DWS-PLW-756 |
| 29 | SV3-PXS-P0W-ME3237 | ASME SECTION III- FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-024 (LINE NUMBERS PXS-PL-L025B, L027B, L054B) |
| 30 | SV3-PXS-P0W-ME3235 | ASME SECTION III- FABRICATION/INSTALLATION OF ISOMETIC# SV3-PXS-PLW-021 (LINE NUMBERS PXS-PL-L015B,L059B) |
| 31 | SV3-PXS-P0W-ME3375 | ASME SECTION III- FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-02D (LINE NUMBERS PXS-PL-L120) |
| 32 | SV3-PXS-P0W-ME3380 | ASME SECTION III- FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-02P (LINE NUMBERS PXS-PL-L018B) |
| 33 | SV3-PXS-P0W-ME3377 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-02K (LINE NUMBERS PXS-PL- L014B, L019B) |
| 34 | SV3-WLS-PHW-ME0837 | FABRICATION/INSTALLATION OF SMALL BORE WLS PIPING SUPPORTS FOR ISOMETRICS SV3-WLS-PLW-480, -484 |
| 35 | SV3-PXS-P0W-ME3376 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-02E (LINE NUMBERS PXS-PL-L114, L120, L112B, L116B, B132B)o |
| 36 | SV3-PXS-P0W-ME3379 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-02N (LINE NUMBERS PXS-PL-L117B) |
| 37 | SV3-WLS-P0W-ME3496 | INSTALLATION OF SMALL BORE WLS PIPING (ISOMETRICS SV3-WLS-PLW-192, -193, -194) |
| 38 | SV3-WLS-PHW-ME3863 | FABRICATION/INSTALLATION OF SMALL BORE WLS PIPING SUPPORTS FOR ISOMETRICS SV3-WLS-PLW-192, -194 |
| 39 | SV4-PY85-PYW-ME2215 | INSTALLATION OF WWS COLLECTION BASIN SV4-WWS-PY-D501 |
| 40 | SV3-WLS-P0W-ME3497 | INSTALLATION OF SMALL BORE WLS PIPING (ISOMETRICS SV3-WLS-PLW-195, -196) |
| 41 | SV3-CCS-P0W-ME3837 | INSTALLATION OF LARGE BORE CCS PIPING INCLUDING ISOMETRICS SV3-CCS-PLW-021 , -022 |
| 42 | SV3-ME01-PHW-ME1282 | UNIT 3 CONDENSER C: FABRICATION OF 2ND EXTRACTION STEAM PIPING SUPPORTS |
| 43 | SV3-CAS-PHW-ME2790 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-CAS-PLW-86C |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 44 | SV3-PXS-P0W-ME3834 | ASME SECTION III- FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-185 (LINE NUMBERS PXS-PLL014A, L019A) |
| 45 | SV3-PXS-P0W-ME3835 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-20A (LINE NUMBERS PXS-PL-L120, L150), , |
| 46 | SV3-WLS-PHW-ME0833 | FABRICATION/INSTALLATION OF SMALL BORE WLS PIPING SUPPORTS FOR ISOMETRICS SV3-WLS-PLW-90B, -904 |
| 47 | SV3-WLS-PHW-ME0827 | FABRICATION/INSTALLATION OF SMALL BORE WLS PIPE SUPPORTS FOR ISOMETRIC DRAWING WLS-PLW-591 |
| 48 | SV3-WLS-PHW-ME3864 | FABRICATION/INSTALLATION OF SMALL BORE WLS PIPING SUPPORTS FOR ISOMETRICS SV3-WLS-PLW-195, -196 |
| 49 | SV3-WLS-PHW-ME3861 | FABRICATION/INSTALLATION OF SMALL BORE WLS PIPING SUPPORTS FOR ISOMETRICS SV3-WLS-PLW-299, -300 |
| 50 | SV3-WLS-PHW-ME0825 | FABRICATION/INSTALLATION OF SMALL BORE WLS PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-WLS-PLW-490 |
| 51 | SV3-WLS-PHW-ME3410 | FABRICATION/INSTALLATION OF SMALL BORE WLS PIPING SUPPORTS FOR ISOMETRIC: SV3-WLS-PLW-040 |
| 52 | SV3-WLS-PHW-ME2321 | FABRICATION/INSTALLATION OF SMALL BORE WLS PIPE SUPPORTS FOR ISOMETRIC DRAWING WLS-PLW-212 |
| 53 | SV3-CVS-P0W-ME2650 | INSTALLATION OF SMALL BORE CVS PIPING (INCLUDES ISOMETRICS SV3-CVS-PLW-04E) |
| 54 | SV3-CVS-P0W-ME2652 | INSTALLATION OF SMALL BORE CVS PIPING (INCLUDES ISOMETRICS SV3-CVS-PLW-04G) |
| 55 | SV3-CVS-P0W-ME2653 | INSTALLATION OF SMALL BORE CVS PIPING (INCLUDES ISOMETRICS SV3-CVS-PLW-04J) |
| 56 | SV3-CVS-P0W-ME2651 | INSTALLATION OF SMALL BORE CVS PIPING (INCLUDES ISOMETRIC: SV3-CVS-PLW-04F) |
| 57 | SV3-CAS-P0W-ME2120 | FABRICATE AND INSTALL CAS SMALL BORE PIPING SHOWN ON ISOMETRIC DRAWING #SV3-CAS-PLW-863, SV3-CAS-PLW-86C, SV3-CAS-PLW-86D, AND SV3-CAS-PLW-86H |
| 58 | SV3-CVS-P0W-ME2649 | INSTALLATION OF SMALL BORE CVS PIPING (INCLUDES ISOMETRIC: SV3-CVS-PLW-04D) |
| 59 | SV3-4033-CRW-CV2839 | U3 ANNEX AREA 3 CONCRETE REINFORCEMENT ELEVATION 100'-0" TO 107'2" |
| 60 | SV3-WLS-PHW-ME0826 | FABRICATION/INSTALLATION OF SMALL BORE WLS PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-WLS-PLW-590 |
| 61 | SV3-WLS-P0W-ME3499 | INSTALLATION OF SMALL BORE WLS PIPING (ISOMETRICS SV3-WLS-PLW-235, -245) |
| 62 | SV3-CVS-PHW-ME4188 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-CVS-PLW-524, 533, 560 |
| 63 | SV3-WWS-ERW-EL0744 | INSTALLATION OF ELECTRICAL UNDERGROUND COMMODITIES (MANHOLES AND DUCT BANKS) FOR THE (WWS) WASTE WATER SYSTEM. |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 64 | SV3-1210-EGW-EL1070 | U3-AUXILIARY BUILDING INSTALL ELECTRICAL PENETRATIONS AND GROUNDING FOR WALLS 21, 22, 23 AND 24 EL 66'6" TO 82'-6" |
| 65 | SV0-ZFS-ERW-EL2716 | INSTALL ZFS DUCTBANK-PHASE 5 TO PHASE 4 |
| 66 | SV0-SES-ERW-EL2689 | SV0-INSTALL SES PLANT SECURITY DUCT BANKS-PHASE 5 |
| 67 | SV3-4030-EGW-EL1855 | UNDERGROUND COMMODITIES (EGS-GROUNDING) FOR THE ANNEX BLDG., AREA 2, ELEV. 100' TO 107' |
| 68 | SV0-SES-ERW-EL2274 | SES DUCTBANK FROM NORTHEAST OF DIESEL @ MANHOLE TO NORTH OF TRANSFORMER AREA (PHASE 2) |
| 69 | SV3-2040-EGW-EL1457 | ELECTRICAL GROUNDING INSTALLATION FOR THE TURBINE BUILDING AT ELEVATIONS 117'-6" AND 120'-6" |
| 70 | SV3-0000-EGW-EL1895 | PERFORM INSTALLATION OF UNDERGROUND COMMODITIES (SV3-SITE STATION GROUNDING GRID) FOR GROUND GRID AREAS L1300, L1400 AND M1400 IN SUPPORT OF ANNEX PHASE 1 WORK |
| 71 | SV0-ZFS-ERW-EL2427 | INSTALL ZFS DUCTBANK NORTH OF TURBINE BLDG. - PHASE 2 |
| 72 | SV0-ZFS-ERW-EL2663 | INSTALL ZFS DUCTBANK - PHASE 7 TO PHASE 3 |
| 73 | SV3-R104-ERW-EL4154 | INSTALLATION OF ELECTRICAL CABLE TRAY IN MODULE R104 |
| 74 | SV3-1120-ERW-EL2350 | FABRICATION AND INSTALLATION OF CABLE TRAY SUPPORTS FOR ROOM 11201 EL. 84'6" THROUGH 107'-2" |
| 75 | SV4-CA20-S4W-CV5609 | CA20-21 MAP OUT TEMPORARY ATTACHMENTS |
| 76 | SV0-ZRS-EWW-EL1582 | Power Loop and Service Feeders for Buildings 301,302,303,304,305,306,307,321,322, and 324 |
| 77 | SV4-ML10-MLW-ME5900 | PLACEMENT OF CONTAINMENT PENETRATIONS P19, P20, P22 |
| 78 | SV3-1212-ERW-EL1618 | INSTALL DESIGN ROUTED RACEWAY AND SUPPORTS FOR DIVISION "A" BATTERY ROOM EL. 66'6" |
| 79 | SV3-1212-ERW-EL1622 | INSTALL DESIGN ROUTED RACEWAY AND SUPPORTS FOR SPARE BATTERY ROOM 3L. 66'-6" |
| 80 | SV3-2040-SSW-CV3301 | UNIT 3 TURBINE BUILDING SEQUENCE 10 HANDRAIL & STAIRS |
| 81 | SV3-2000-T2W-CV0618 | HSB ASSEMBLY & INSTALLER QUALIFICATION FOR TURBINE BUILDING |
| 82 | SV3-2020-SUW-CV0182 | TURBINE BUILDING SET MODULES CH80, CH81A, CH81B, CH81C, & CH82 |
| 83 | SV3-2040-SUW-CV1186 | TURBINE BUILDING STRUCTURAL STEEL SEQUENCE 8 |
| 84 | SV3-2040-SUW-CV1189 | Turbine Building Structural Steel Framing Sequence 11 |
| 85 | SV3-2000-SUW-CV1391 | RE-WORK OF CH80 STRUCTURAL STEEL |
| 86 | SV3-CVS-PLW-CV0560 | Installation of Large Bore FPS Piping (Includes Isometrics SV3-CVS-PLW-561, SV3-CVS-PLW-562) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 87 | SV3-WWS-PHW-ME4634 | INSTALLATION OF TURBINE BUILDING WWS PIPING SUPPORTS FOR SLAB 1 ON 120'-6" |
| 88 | SV3-SDS-PLW-ME1267 | INSTALL SANITARY DRAIN LIFT STATION MS-501. |
| 89 | SV3-SWS-PLW-ME1357 | INSTALLATION OF SWS LARGE BORE PIPING (INCLUDES ISOMETRICS SV3-SWS-PLW-030, 031, 034, 035, 065, 066, 06A, 06B) |
| 90 | SV3-ASS-PHW-ME1520 | FABRICATE/INSTALL OF AUXILIARY STEAM (ASS) SUPPORTS (PORTION 2) FOR ISOMETRIC# SV3-ASS-PLW-02L, 02D, 029, 025, & 026 |
| 91 | SV0-PWS-PLW-ME1085 | FABRICATE AND INSTALL POTABLE WATER PIPING BETWEEN BUILDINGS 302 AND 303 TO BUILDING 307 |
| 92 | SV3-PY85-PYW-ME1920 | INSTALLATION OF WWS COLLECTION BASIN SV3-WWS-PY-D501 |
| 93 | SV3-CES-PHW-ME1851 | FABRICATION AND INSTALLATION OF PIPE SUPPORTS FOR (ISO SV3-CES-PLW-700, 711, 720, 730, 731, 732, 733, 734, 735, 736, 780) |
| 94 | SV3-2050-MEW-ME1900 | Unit 3 Turbine/Generator Deck Spring Support Foundation Installation |
| 95 | SV3-SDS-PLW-ME1656 | FABRICATE AND INSTALL SANITARY DRAIN PIPING FROM THE STANDARD PLANT TIE-INS @ THE ANNEX BLDG TO LIFT STATION MS-501 |
| 96 | SV4-WLS-P0W-ME2909 | FABRICATE AND INSTALL UNIT 4 WLS PIPING FROM RADWASTE BUILDING THROUGH PHASE 5 |
| 97 | SV3-WLS-PLW-ME0586 | INSTALLATION OF WLS LARGE BORE PIPING (INCLUDING ISOMETRICS SV3-WLS-PLW-362) |
| 98 | SV3-TCS-PHW-ME2390 | Installation Of TCS Piping Supports For Piping Included In The SV3-TCS-PLW-ME2389 Work Package |
| 99 | SV3-CDS-PHW-ME3712 | INSTALLATION OF CDS PIPING SUPPORTS ON 100' ELEVATION |
| 100 | SV3-CES-PHW-ME1750 | Fabrication and Installation of Pipe Supports for (ISO SV3-CES-PLW-740, 751, 760, 770, 771, 772, 773, 774, 775, 776, 777, 790) |
| 101 | SV3-WWS-PHW-ME2046 | UNIT 3 TURBINE BUILDING EL 82FT.-9IN. WWS PIPING SUPPORTS |
| 102 | SV0-SES-ERW-EL4203 | INSTALL CONDUIT IN SES DUCT BANK BETWEEN UNIT 3 AND UNIT 4 (FROM MANHOLE NXM689-NXM688 AND EVERYTHING BETWEEN) |
| 103 | SV0-SES-ERW-EL4204 | INSTALL CONDUIT IN SES DUCT BANK BETWEEN UNIT 3 AND UNIT 4 (FROM MANHOLE NXM688-NXM685 AND EVERYTHING BETWEEN) |
| 104 | SV0-2000-EWW-TP0878 | TEMPORARY POWER FOR TURBINE BUILDING |
| 105 | SV3-2040-SUW-CV1185 | Turbine Building Structural Steel Framing Sequence 7 |
| 106 | SV3-2000-SUW-CV0180 | Assembly and erection of CH80 module in Area 111 |
| 107 | SV3-2030-SUW-CV0190 | Structural Steel Framing (El. 100") |
| 108 | SV3-2000-SUW-CV0183 | Assembly and Erection of CH81A, B & C Module in Area 111 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 109 | SV4-VWS-P0W-ME4484 | ASME SECTION III - FABRICATION / INSTALLATION OF ISOMETRIC# SV4-VWS-PLW-910 (LINE# VWS-PL-L032) |
| 110 | SV3-MS21-MEW-001 | INSTALLATION OF SSS CONDENSER HOTWELL PUMPS (SSS-MS-01A/B/C) |
| 111 | SV3-2101-MLW-ME3349 | INSTALLATION OF EMBEDDED PIPING PENETRATION WALL SLEEVES (SLAB1) |
| 112 | SV3-WWS-PLW-ME0911 | Unit 3 Turbine Building, EL 100'-0" Bay 1 Embedded WWS Piping Package #2 |
| 113 | SV3-WWS-PLW-ME1101 | UNIT 3 TURBINE BUILDING EL 100FT.-0IN. EMBEDDED WWS PIPING PACKAGE # 3 |
| 114 | SV0-1000-EWW-TP1689 | CONSTRUCTION POWER RE-ROUTE AT NUCLEAR ISLAND UNIT 3 |
| 115 | SV3-1210-EGW-EL1069 | U3-Aux Bldg. Grounding and Conduit Sleeves/Penetrations for Wall Pours 13,14,15,19,20,20B and Hall 12111 Header |
| 116 | SV3-CB65-S4WP-CV1663 | CB65 ASSEMBLY |
| 117 | SV3-1210-EGW-EL1066 | Unit 3 Auxillary Bldg EL.66'-6" Grounding Work Package for Wall 3 |
| 118 | SV3-2060-CCW-CV0130 | INSTALL REBAR, EMBEDDED ITEMS, AND CONCRETE UNIT 3 TURBINE TABLE TOP (CA81) |
| 119 | SV3-2040-CCW-CV0124 | 120'-6" Elevated Slabs Unit 3 Turbine |
| 120 | SV3-ASS-PHW-ME1428 | FABRICATE/INSTALL OF AUXILIARY STEAM (ASS) SUPPORTS (PORTION 1) FOR ISOMETRIC# SV3-ASS-PLW-016, 01U, 1E, & 01F |
| 121 | SV3-2131-CCW-CV0185 | Unit 3 Turbine Building First Bay 100' Slab and Equipment Pads |
| 122 | SV3-ASS-PLW-ME1474 | FABRICATE AND INSTALL AUXILIARY STEAM SYSTEM(ASS) PIPING PORTION 2 FOR 82-9 |
| 123 | SV3-CDS-THW-ME1204 | PERFORM PRESSURE TEST ON UNIT 3 CONDENSATE PIPING FROM CONDENSER TO PUMPS |
| 124 | SV3-2040-SSW-CV3298 | UNIT 3 TURNINBE BULDING SEQUENCE 7 HANDRAIL & STARIS |
| 125 | SV3-WLS-PHW-ME0834 | FABRICATION/INSTALLATION OF SMALL BORE WLS PIPING SUPPORTS FOR ISOMETRICS SV3-WLS-PLW-35M, -355, -357 |
| 126 | SV3-WRS-PLW-ME0604 | WRS LARGE BORE PIPING INSTALLATION (INCLUDES ISOMETRIC SV3-WRS-PLW-57A, 570, 57G AND 57H) |
| 127 | SV3-2030-CWS-ME1354 | Installation of (2) 120" CWS Butterfly Valves (Condenser Supply) Piping and Components to Condenser A |
| 128 | SV3-WRS-PLW-ME0598 | Installation of CR-10 Piping |
| 129 | SV3-WRS-P0W-ME2260 | ANNEX BUILDING - EMBEDDED WRS PIPING PACKAGE #2 |
| 130 | SV3-CWS-PLW-ME2521 | INSTALLATION OF CWS PIPING |
| 131 | SV3-2020-SSW-CV1075 | TURBINE BUILDING CONDENSERS TEMPORARY HYDRO SUPPORT |
| 132 | SV3-DWS-P0W-ME6674 | INSTALLATION OF ANNEX BLDG DWS PIPING (ISOMETRICS SV3-DWS-PLW-140, 141) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 133 | SV3-1230-CCW-CV2445 | AUX BUILDING MISCELLANEOUS WALLS (49, 50, 51, 52 & 53) UP TO EL 100'-0" |
| 134 | SV3-1230-CCW-CV2446 | AUX BUILDING MISCELLANEOUS WALLS (54, 55, 56 & 57) UP TO EL 100'-0" |
| 135 | SV3-1200-T2W-CV3353 | HSB Assembly & Installer Qualification for U3 Auxiliary Building |
| 136 | SV4-1220-CCW-CV4323 | UNIT 4 NUCLEAR ISLAND AUXILIARY BUILDING AREAS 3 THROUGH 6 CONCRETE PLACEMENTS FOR INTERIOR WALLS FROM ELEVATION 82'-6" TO 100'-0" |
| 137 | SV4-1220-CEW-CV3879 | AUXILIARY BUILDING: AREAS 1 & 2, ELEVATION 82' 6" FLOOR SLAB EMBEDMENT, BLOCKOUTS & FORM WORK" |
| 138 | SV4-1220-CEW-CV3880 | AUXILIARY BUILDING: AREAS 3 & 4, ELEVATION 82' 6" FLOOR SLAB EMBEDMENT, BLOCKOUTS & FORM WORK" |
| 139 | SV3-1220-CSW-CV2468 | Auxiliary Building S02 Stair Tower Elevation 66'-6" to 100'-0"" |
| 140 | SV3-1160-SSW-CV3060 | C8 Circular Trunk SPL25, 26, 27 |
| 141 | SV3-1172-SSW-CV4544 | Polar Crane Platforms SPL35, SPL36 SPL37 |
| 142 | SV3-1132-SSW-CV6256 | SPL11 INSTALLATION |
| 143 | SV3-1120-ERW-EL2742 | INSTALLATION OF CONDUIT SUPPORTS IN ROOM 11202 EL 84'-6" THROUGH 107'-2" |
| 144 | SV3-1120-ERW-EL2820 | Installation of Conduit Supports in Room 11202 EL 84'-6" through 107'-2"" |
| 145 | SV3-1120-ERW-EL2821 | Installation of Conduit Supports in Room 11202 EL 84'-6" through 107'-2"" |
| 146 | SV3-1120-ERW-EL3521 | Fabrication and Installation of Design Routed Conduit Supports in Room 11204 at Elevation 84' 6"" |
| 147 | SV3-1120-ERW-EL3523 | Fabrication and Installation of Design Routed Conduit Supports in Room 11204 at Elevation 84' 6"" |
| 148 | SV3-1210-ERW-EL1625 | AUXILARY BUILDING UNIT 3, EL 66'-6", AREA 5, INSTALL DESIGNED CABLE TRAYS AND SUPPORTS |
| 149 | SV3-1210-ERW-EL3162 | AUXILARY BUILDING UNIT 3, EL 66'-6", AREA 6, INSTALL DESIGNED RACEWAYS AND SUPPORTS." |
| 150 | SV3-1210-ERW-EL3673 | FABRICATE AND INSTALL FIELD ROUTED TYPICAL CONDUIT SUPPORT C13 FOR AUX BUILDING (AREAS 1 & 2) EL 66'-6" TO 82'-6" |
| 151 | SV3-1210-ERW-EL3674 | FABRICATE AND INSTALL FIELD ROUTED TYPICAL CONDUIT SUPPORT C14 FOR AUX BUILDING (AREAS 1 & 2) EL 66'-6" TO 82'-6" |
| 152 | SV3-1210-ERW-EL3675 | FABRICATE AND INSTALL FIELD ROUTED TYPICAL CONDUIT SUPPORT C15 FOR AUX BUILDING (AREAS 1 & 2) EL 66'-6" TO 82'-6" |
| 153 | SV3-1210-ERW-EL3676 | FABRICATE AND INSTALL FIELD ROUTED TYPICAL CONDUIT SUPPORT C29 FOR AUX BUILDING (AREAS 1 & 2) EL 66'-6" TO 82'-6" |
| 154 | SV3-1210-ERW-EL3677 | FABRICATE AND INSTALL FIELD ROUTED TYPICAL CONDUIT SUPPORT C31 FOR AUX BUILDING (AREAS 1 & 2) EL 66'-6" TO 82'-6" |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 155 | SV3-1213-ERW-EL3682 | Fabricate and Install Field Routed Typical Conduit Support C31 for AUX Building (Areas 3 & 4) EL 66'-6" to 82'-6"" |
| 156 | SV3-1214-ERW-EL3167 | Auxiliary Building Unit 3, El 66'-6", Area 4, Install Scheduled Conduits and Scheduled Pull Boxes. |
| 157 | SV3-CA20-SHW-EL5045 | Field routed typical conduit support C13 for CA20 module, Elev. 66'-6" to 135'-0" |
| 158 | SV3-1212-ERW-EL3164 | AUXILARY BUILDING UNIT 3, EL 66'-6", AREA 2, INSTALL SCHEDULED CONDUITS AND SCHEDULED PULL BOX" |
| 159 | SV3-1215-ERW-EL1628 | AUXILARY BUILDING UNIT 3, EL 66'-6", AREA 5, INSTALL SCHEDULED CONDUITS " |
| 160 | SV3-1231-EGW-EL6064 | U3 -AUXILIARY BUILDING Install Grounding For Walls EL 100' 0" To 117' 6", to include pigtails for extensions to Elev. 135'-3" Areas 1 & 2" |
| 161 | SV0-DOS-ERW-EL2747 | Install Electrical Duct Bank SV0-0000-ER-NXD0701 from Pumphouse Switchgear 315 Bldg. to Main Diesel Fuel Pump Pad |
| 162 | SV0-SES-ERW-EL4609 | Install Conduit in SES Duct Bank Between Unit 3 and Unit 4 (From Manhole NXM685-NXM657 and everything between) |
| 163 | SV3-1233-EGW-EL6065 | Install ground cables and wall plates for walls from Elev. 100'-0" - 117'-6" to include pigtails for extensions to Elev. 135'-3" Areas 3 & 4" |
| 164 | SV3-1235-EGW-EL6066 | Install ground cables and wall plates for walls from Elev. 100'-0" - 117'-6" to include pigtails for extensions to Elev. 135'-3" Areas 5 & 6" |
| 165 | SV3-ME01-PHW-ME1274 | UNIT 3 CONDENSER A: FABRICATION & INSTALLATION OF 2ND EXTRACTION STEAM PIPING SUPPORTS |
| 166 | SV3-CAS-P0W-ME4474 | Fabricate and Install Annex Compressed and Instrument Air System (CAS) piping IAW (Isometrics SV3-CAS-PLW-25H, -25T -25W, -25X, -253, -254) |
| 167 | SV3-ML05-MLW-ME4937 | INSTALLATION OF 100' FLOOR PIPING PENETRATIONS |
| 168 | SV3-PXS-P0W-ME2996 | ASME Section III - Fabrication/Installation of Isometric# SV3-PXS-PLW-620 (Line Numbers PXS-PL-L032B) |
| 169 | SV3-PXS-P0W-ME2997 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-640 (LINE NUMBERS PXS-PL-L032A), , |
| 170 | SV3-PXS-P0W-ME2999 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-680 (LINE NUMBERS PXS-PL-L035A), , |
| 171 | SV3-PXS-P0W-ME3001 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-700 (LINE NUMBERS PXS-PL-L038A), , |
| 172 | SV3-PXS-P0W-ME3003 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-731 (LINE NUMBERS PXS-PL-L053A), , |
| 173 | SV3-PXS-P0W-ME3004 | ASME Section III - Fabrication/Installation of Isometric# SV3-PXS-PLW-740 (Line Numbers PXS-PL-L031B) |
| 174 | SV3-PXS-P0W-ME3005 | ASME Section III - Fabrication/Installation of Isometric# SV3-PXS-PLW-750 (Line Numbers PXS-PL-L031A) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 175 | SV3-PXS-P0W-ME3006 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-761 (LINE NUMBERS PXS-PL-L052A), , |
| 176 | SV3-PXS-P0W-ME3373 | ASME Section III - Fabrication/Installation of Isometric# SV3-PXS-PLW-02B, -02C, -090 (Line Numbers PXS-PL-L100, L101, L106, L113B, L131B) |
| 177 | SV3-RCS-P0W-ME8613 | ASME SECTION III - FABRICATION/INSTALLATION OF PIPE FOR ISOMETRIC SV3-RCS-PLW-840 |
| 178 | SV3-RCS-P0W-ME8614 | ASME SECTION III - FABRICATION/INSTALLATION OF PIPE FOR ISOMETRIC SV3-RCS-PLW-841 |
| 179 | SV3-RNS-P0W-ME5059 | ASME Section III - Fabrication/Installation of Isometric SV3-RNS-PLW-390 (Line Number RNS-PL-L044) |
| 180 | SV3-RNS-P0W-ME5060 | ASME Section III - Fabrication/Installation of Isometric SV3-RNS-PLW-402 (Line Number RNS-PL-L041) |
| 181 | SV3-RNS-P0W-ME5061 | ASME Section III - Fabrication/Installation of Isometric SV3-RNS-PLW-411 (Line Number RNS-PL-L043) |
| 182 | SV3-RNS-P0W-ME5062 | ASME Section III - Fabrication/Installation of Isometric SV3-RNS-PLW-422 (Line Number RNS-PL-L042) |
| 183 | SV3-RNS-P0W-ME5501 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC SV3-RNS-PLW-190 (LINE NUMBER RNS-PL-L018B), |
| 184 | SV3-2101-MLW-ME3350 | INSTALLATION OF TURBINE BUILDING 1ST BAY EMBEDDED PIPING PENETRATION WALL SLEEVES (PLACEMENT 2). |
| 185 | SV3-2101-MLW-ME3351 | INSTALLATION OF TURBINE BUILDING 1ST BAY EMBEDDED PIPING PENETRATION WALL SLEEVES (PLACEMENT 3 & 4). |
| 186 | SV3-CAS-P0W-ME3432 | INSTALLATION OF SMALL BORE CAS PIPING (INCLUDES SV3-CAS-PLW-319, 41B, 41H, 417) |
| 187 | SV3-CVS-P0W-ME2654 | Installation of Small Bore CVS Piping (Includes Isometrics: SV3-CVS-PLW-06G, 06H) |
| 188 | SV3-DWS-P0W-ME3927 | Installation of Large Bore DWS Piping Including Isometrics SV3-DWS-PLW-61E |
| 189 | SV3-DWS-P0W-ME4320 | Installation of Small Bore DWS Piping Including Isometrics SV3-DWS-PLW-61J |
| 190 | SV3-DWS-PHW-ME4599 | Fabrication/Installation of Small Bore DWS Pipe Supports for Isometric Drawing SV3-DWS-PLW-61J |
| 191 | SV3-FPS-P0W-ME4183 | INSTALLATION OF LARGE BORE FPS PIPING (INCLUDES ISOMETRICS SV3-FPS-PLW-71B, -71C, -71D) |
| 192 | SV3-FPS-P0W-ME4184 | INSTALLATION OF LARGE BORE FPS PIPING (INCLUDES ISOMETRICS SV3-FPS-PLW-735, -73A, -71A) |
| 193 | SV3-PWS-P0W-ME4168 | Installation of Small Bore PWS Piping (Includes Isometric SV3-PWS-PLW-300, 305) |
| 194 | SV3-PWS-PHW-ME5276 | Fabrication/Installation of Small Bore PWS Piping Supports for Isometric Drawing SV3-PWS-PLW-300 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 195 | SV3-PWS-PHW-ME5277 | FABRICATION/INSTALLATION OF SMALL BORE PWS PIPING SUPPORTS FOR ISOMETRIC DRAWING SV3-PWS-PLW-912, 922, 940, 941, 948 |
| 196 | SV3-PWS-PHW-ME5282 | FABRICATION/INSTALLATION OF SMALL BORE PWS PIPING SUPPORTS FOR ISOMETRIC DRAWING SV3-PWS-PLW-921 |
| 197 | SV3-SFS-P0W-ME4350 | INSTALLATION OF LARGE BORE SFS PIPING (INCLUDES SV3-SFS-PLW-410, 420, 430) |
| 198 | SV3-WLS-P0W-ME3480 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES ISOMETRIC SV3-WLS-PLW-64L) |
| 199 | SV3-WLS-P0W-ME3481 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES ISOMETRIC SV3-WLS-PLW-64M) |
| 200 | SV3-WLS-P0W-ME3482 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES ISOMETRIC SV3-WLS-PLW-64N) |
| 201 | SV3-WLS-P0W-ME3483 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES ISOMETRIC SV3-WLS-PLW-64O) |
| 202 | SV3-WLS-P0W-ME3504 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES: SV3-WLS-PLW-415, SV3-WLS-PLW-421, SV3-WLS-PLW-440, SV3-WLS-PLW-441) |
| 203 | SV3-WLS-P0W-ME3728 | Installation of Small Bore WLS Piping (Isometric SV3-WLS-PLW-550,-551,-560,-56A |
| 204 | SV3-WLS-P0W-ME3732 | Installation of Small Bore WLS Piping (Isometric SV3-WLS-PLW-610, 61A, 620, 62A) |
| 205 | SV3-WLS-P0W-ME3735 | INSTALLATION OF SMALL BORE WLS PIPING (ISOMETRIC SV3-WLS-PLW-933, 960, 970) |
| 206 | SV3-WLS-PHW-ME4875 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-WLS-PLW-61A, 62A, 610, 620 |
| 207 | SV3-WRS-P0W-ME3796 | INSTALLATION OF LARGE BORE WRS PIPING (INCLUDES SV3-WRS-PLW-65M, 65N, 65P, 65R, 651) |
| 208 | SV3-WSS-PHW-ME4398 | FABRICATION/INSTALLATION OF SMALL BORE WSS PIPING SUPPORTS (INCLUDES ISOMETRICS SV3-WSS-PLW-513, 514, 600, 601) |
| 209 | SV3-WWS-P0W-ME3445 | INSTALLATION OF 82'6" WWS PIPING ( SV3-WWS-PLW-01C, 323, 325) |
| 210 | SV3-WWS-PHW-ME5520 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-WWS-PLW-31F |
| 211 | SV4-CCS-P0W-ME4818 | INSTALLATION OF LARGE BORE CCS PIPING (ISOMETRIC SV4-CCS-PLW-130) |
| 212 | SV4-KQ11-KQW-ME5029 | INSTALL MECHANICAL EQUIPMENT MODULE KQ11(MP-02A, MP-02B) - PORTION 2 |
| 213 | SV4-WWS-PHW-ME5521 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV4-WWS-PLW-31F |
| 214 | SV3-CAS-PHW-ME6003 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWINGS (SV3-CAS-PLW-413, 414) |
| 215 | SV3-DWS-PHW-ME6280 | Fabrication/Installation of Small Bore DWS Pipe Supports for Isometric Drawing SV3-DWS-PLW-61E |
| 216 | SV3-SFS-P0W-ME4351 | Installation of Large Bore SFS Piping (SV3-SFS-PLW-450) |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 217 | SV3-SFS-P0W-ME4352 | INSTALLATION OF LARGE BORE SFS PIPING (SV3-SFS-PLW-470, 490, 532, 539) |
| 218 | SV3-SFS-P0W-ME4353 | INSTALLATION OF LARGE BORE SFS PIPING (SV3-SFS-PLW-53A, 53B, 53C, 53D, 53E) |
| 219 | SV3-WLS-P0W-ME3501 | Installation of Small Bore WLS Piping (Isometrics SV3-WLS-PLW-318, 319, 320) |
| 220 | SV4-FPS-P0W-ME1941 | INSTALLATION OF LARGE BORE FPS PIPING (INCLUDES ISOMETRICS: SV4-FPS-PLW-810, 815) |
| 221 | SV4-VCS-P0W-ME6175 | INSTALLATION OF SMALL BORE VCS PIPING SHOWN ON ISOMETRIC: SV4-VCS-PLW-010. |
| 222 | SV4-MT6F-MEW-ME5674 | Installation of the Main Feedwater Pump Seal Water Drain Collector Tank |
| 223 | SV3-KB25-KBW-ME4600 | SITE COMPLETION OF KB25 MODULE |
| 224 | SV3-KB26-KBW-ME4601 | SITE COMPLETION OF KB26 MODULE |
| 225 | SV4-WLS-THW-ME2911 | Hydro Test the Unit 4 Liquid Radwaste System Piping Phase 5 |
| 226 | SV3-TCS-PHW-ME2398 | INSTALLATION OF TCS SUPPORTS FOR ISOMETRICS SV3-TCS-PLW-820, SV3-TCS-PLW-821, SV3-TCS-PLW-822, SV3-TCS-PLW-823, SV3-TCS-PLW-824, SV3-TCS-PLW-825, SV3-TCS-PLW-826. |
| 227 | SV3-CAS-P0W-ME3428 | INSTALLATION OF SMALL BORE CAS PIPING (INCLUDES SV3-CAS-PLW-312, 332, 335, 415, 894) |
| 228 | SV3-CCS-P0W-ME4090 | INSTALLATION OF SMALL BORE CCS PIPING INCLUDING ISOMETRICS SV3-CCS-PLW-318 , -328 |
| 229 | SV3-CPS-P0W-ME3589 | INSTALLATION OF CPS PIPING |
| 230 | SV3-CVS-P0W-ME3897 | INSTALLATION OF LARGE BORE PIPING (ISOMETRIC SV3-CVS-PLW-57J AND 507) |
| 231 | SV3-CVS-P0W-ME3899 | INSTALLATION OF LARGE BORE PIPING (ISOMETRIC SV3-CVS-PLW-57N AND 50A) |
| 232 | SV3-CVS-P0W-ME3920 | INSTALLATION OF SMALL BORE CVS PIPING (INCLUDES ISOMETRICS: SV3-CVS-PLW-810, -830) |
| 233 | SV3-CVS-PHW-ME4189 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-CVS-PLW-563, 564, 566, 567, 568 |
| 234 | SV3-DWS-P0W-ME3923 | INSTALLATION OF SMALL BORE DWS PIPING INCLUDING ISOMETRICS SV3-DWS-PLW-60E , -614 |
| 235 | SV3-DWS-P0W-ME3924 | INSTALLATION OF SMALL BORE DWS PIPING INCLUDING ISOMETRICS SV3-DWS-PLW-617 |
| 236 | SV3-DWS-P0W-ME3925 | INSTALLATION OF SMALL BORE DWS PIPING INCLUDING ISOMETRICS SV3-DWS-PLW-61A |
| 237 | SV3-DWS-P0W-ME3926 | INSTALLATION OF LARGE BORE DWS PIPING INCLUDING ISOMETRICS SV3-DWS-PLW-61C |
| 238 | SV3-DWS-P0W-ME4314 | INSTALLATION OF SMALL BORE DWS PIPING INCLUDING ISOMETRICS SV3-DWS-PLW-618 |
| 239 | SV3-DWS-P0W-ME4316 | INSTALLATION OF SMALL BORE DWS PIPING INCLUDING ISOMETRICS SV3-DWS-PLW-61D |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 240 | SV3-DWS-P0W-ME4317 | INSTALLATION OF SMALL BORE DWS PIPING INCLUDING ISOMETRICS SV3-DWS-PLW-61G |
| 241 | SV3-FPS-P0W-ME4179 | INSTALLATION OF LARGE BORE FPS PIPING (INCLUDES ISOMETRICS SV3-FPS-PLW-70J, -70P, -70S) |
| 242 | SV3-FPS-P0W-ME4180 | INSTALLATION OF LARGE BORE FPS PIPING (INCLUDES ISOMETRICS SV3-FPS-PLW-70V, -70W, -70Y, -70Z) |
| 243 | SV3-FPS-P0W-ME4181 | INSTALLATION OF LARGE BORE FPS PIPING (INCLUDES ISOMETRICS SV3-FPS-PLW-712, -713) |
| 244 | SV3-ME01-PHW-ME1278 | UNIT 3 CONDENSER B: FABRICATION OF 2ND EXTRACTION STEAM PIPING SUPPORTS |
| 245 | SV3-PGS-P0W-ME4165 | INSTALLATION OF SMALL BORE PGS PIPING (ISOMETRIC SV3-PGS-PLW-104) |
| 246 | SV3-PWS-P0W-ME4942 | INITIAL ENERGIZATION - INSTALLATION OF ANNEX POTABLE WATER SYSTEM (PWS) PIPING INCLUDING ISOMETRICS: SV3-PWS-PLW-180, -181, -182, -411, -413, & 419 |
| 247 | SV3-PWS-PHW-ME4943 | INITIAL ENERGIZATION - INSTALLATION OF ANNEX POTABLE WATER SYSTEM (PWS) PIPING SUPPORTS FOR WP (SV3-PWS-P0W-ME4942) |
| 248 | SV3-VAS-P0W-ME4958 | Installation of Large Bore VAS Piping (Isometric SV3-VAS-PLW-320) |
| 249 | SV3-VAS-PHW-ME4959 | Fabrication/Installation of Pipe Supports for Isometric Drawing SV3-VAS-PLW-320 |
| 250 | SV3-VWS-P0W-ME4882 | FABRICATION/INSTALLATION OF SMALL BORE VWS PIPING (INCLUDES ISOMETRICS SV3-VWS-PLW-313 , -314 , -315) |
| 251 | SV3-VWS-P0W-ME4883 | FABRICATION/INSTALLATION OF SMALL BORE VWS PIPING (INCLUDES ISOMETRICS SV3-VWS-PLW-343 , -344 , -345) |
| 252 | SV3-VWS-P0W-ME4884 | FABRICATION/INSTALLATION OF SMALL BORE VWS PIPING (INCLUDES ISOMETRICS SV3-VWS-PLW-413 , -414 , -415) |
| 253 | SV3-VWS-P0W-ME4885 | FABRICATION/INSTALLATION OF SMALL BORE VWS PIPING (INCLUDES ISOMETRICS SV3-VWS-PLW-443 , -444 , -445) |
| 254 | SV3-VWS-PHW-ME5326 | ANNEX - Initial Energization Supports - Iso 171, 180, 181, 190, 191, & 197 |
| 255 | SV3-WLS-P0W-ME3734 | INSTALLATION OF LARGE BORE WLS PIPING (ISOMETRIC SV3-WLS-PLW-780, 800, 860) |
| 256 | SV3-WLS-PHW-ME3860 | FABRICATION/INSTALLATION OF SMALL BORE WLS PIPING SUPPORTS FOR ISOMETRICS SV3-WLS-PLW-261, -271, -281 |
| 257 | SV3-WLS-PHW-ME4200 | Fabrication/Installation of Small Bore WLS Piping Supports for Isometrics SV3-WLS-PLW-933 |
| 258 | SV3-WLS-PHW-ME5861 | Fabrication/Installation of Pipe Supports for Isometric Drawing SV3-WLS-PLW-33P. |
| 259 | SV3-WLS-PHW-ME5862 | Fabrication/Installation of Pipe Supports for Isometric Drawing SV3-WLS-PLW-333. |
| 260 | SV3-WLS-PHW-ME5865 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-WLS-PLW-420. |
| 261 | SV3-WLS-PHW-ME5866 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-WLS-PLW-421. |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 262 | SV3-WLS-PHW-ME5867 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-WLS-PLW-440. |
| 263 | SV3-WLS-PHW-ME5868 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-WLS-PLW-441. |
| 264 | SV3-WLS-PHW-ME5871 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-WLS-PLW-452. |
| 265 | SV3-WRS-PHW-ME3076 | ANNEX BUILDING - ELEV 100 WRS SUPPORT PACKAGE (FOR WP SV3-WRS-P0W-ME2347) |
| 266 | SV3-WWS-PHW-ME4635 | INSTALLATION OF TURBINE BUILDING WWS PIPING SUPPORTS FOR SLAB'S 4, 5, 6 ON 120'-6" ELEVATION" |
| 267 | SV4-R104-R1W-ME5678 | INSTALLATION OF R104 MODULE |
| 268 | SV4-R155-R1W-ME5679 | INSTALLATION OF R155 MODULE |
| 269 | SV3-CAS-P0W-ME6050 | INSTALLATION OF SMALL BORE CAS PIPING (INCLUDES SV3-CAS-PLW-41D) |
| 270 | SV3-CAS-P0W-ME6052 | INSTALLATION OF SMALL BORE CAS PIPING (INCLUDES SV3-CAS-PLW-317) |
| 271 | SV3-CAS-P0W-ME6053 | INSTALLATION OF SMALL BORE CAS PIPING (INCLUDES SV3-CAS-PLW-314) |
| 272 | SV3-SFS-THW-ME6286 | HYDRO TESTING OF KB25 SFS PIPING |
| 273 | SV3-SFS-THW-ME6287 | HYDRO TESTING OF KB26 SFS PIPING |
| 274 | SV3-WWS-P0W-ME6195 | ANNEX UNIT 3 - WWS PIPING (ISOMETRICS 484 & 485) |
| 275 | SV3-WWS-PHW-ME6196 | ANNEX UNIT 3 - WWS SUPPORTS (ISOMETRICS 484 & 485) |
| 276 | SV3-1220-CCW-CV1486 | BATTERY RACK WALLS UP TO ELEV. 82'-6" |
| 277 | SV3-CB65-S5W-CV1681 | CB65 OVERLAY PLATE (OLP) INSTALLATION |
| 278 | SV3-CA05-S8W-CV2680 | FINAL INSTALLATION OF CA05 MODULE |
| 279 | SV3-1000-CCW-TP1037 | UNIT 3 NUCLEAR ISLAND TEMPORARY CONSTRUCTION AND FORMWORK |
| 280 | SV0-SM01-CSW-MU1077 | CONCRETE PLACEMENT FOR MODULE PROTOTYPE MOCKUPS: CA20; L, TRANSITION, T; TROUGH; AND COLUMNS. |
| 281 | SV3-2030-CWS-ME1201 | Install Pipe Supports for the CWS from the Turbine Building Penetrations to the Heat Exchangers and Backwash Strainers |
| 282 | SV3-2030-CWS-ME1200 | Installation of the CWS Piping System At Elevation 82'-9" of the Turbine Building; Tie-Ins at Wall Penetrations to Heat Exchangers (SV3-TCS-ME01A,B,C) and Back-Wash Strainers (SV3-CWS-PY-S01A,B&C |
| 283 | SV3-ASS-PHW-ME1427 | FABRICATE/INSTALL OF AUXILIARY STEAM (ASS) SUPPORTS (PORTION 1) FOR ISOMETRIC# SV3-ASS-PLW-01J, 01K, & 01H |
| 284 | SV3-ASS-PHW-ME1426 | FABRICATE/INSTALL OF AUXILIARY STEAM (ASS) SUPPORTS (PORTION 1) FOR ISOMETRIC# SV3-ASS-PLW-019, 018, & 01C |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 285 | SV3-RNS-P0W-ME5056 | ASME Section III - Fabrication/Installation of Isometrics# SV3-RNS-PLW-183 & SV3-RNS-PLW-18C (Line Number RNS-PL-L020,-L018A, -L066A) |
| 286 | SV3-1110-CRW-CV0665 | Unit 3 Containment Concrete Reinforcement up to Elevation 71'6 |
| 287 | SV3-CA04-CEW-CV1686 | CA04 LANDING PLATES POST-INSTALLATION DELIVERABLES |
| 288 | SV3-CA05-S4W-CV1866 | CA05 WALL TEMPORARY ATTACHMENTS |
| 289 | SV3-CAS-PLW-ME0455 | INSTALLATION OF SMALL BORE CAS PIPING (INCLUDES ISOMETRICS: SV3-CAS-PLW-326, 327 & 360) |
| 290 | SV3-PXS-P0W-ME6161 | FABRICATION AND INSTALLATION OF CA03 LARGE BORE PIPING SHOWN ON ISOMETRIC SV3-PXS-PLW-221. |
| 291 | SV4-WLS-P0W-ME5970 | INSTALLATION OF SMALL BORE CA01 WLS PIPING (INCLUDES ISOMETRIC SV4-WLS-PLW-64M) |
| 292 | SV4-WLS-P0W-ME5971 | INSTALLATION OF SMALL BORE CA01 WLS PIPING (INCLUDES ISOMETRIC SV4-WLS-PLW-64N) |
| 293 | SV4-WLS-P0W-ME5969 | INSTALLATION OF SMALL BORE CA01 WLS PIPING (INCLUDES ISOMETRIC SV4-WLS-PLW-64L) |
| 294 | SV4-WLS-P0W-ME5972 | INSTALLATION OF SMALL BORE CA01 WLS PIPING (INCLUDES ISOMETRIC SV4-WLS-PLW-64O) |
| 295 | SV4-WLS-P0W-ME5974 | INSTALLATION OF SMALL BORE CA01 WLS PIPING (INCLUDES ISOMETRIC SV4-WLS-PLW-64Q) |
| 296 | SV4-WLS-P0W-ME2023 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES SV4-WLS-PLW-265, SV4-WLS-PLW-275) |
| 297 | SV3-SFS-P0W-ME5381 | Fabrication/Installation of Isometric SV3-SFS-PLW-757 (Line Numbers SFS-PL-L033) |
| 298 | SV3-SFS-P0W-ME5382 | ASME SECTION III Fabrication/Installation of Isometrics SV3-SFS-PLW-788 & SV3-SFS-PLW-78B (Line Numbers SFS-PL-L035, -L037, -L038, -L098) |
| 299 | SV3-RNS-P0W-ME5494 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC SV3-RNS-PLW-013 (LINE NUMBER RNS-PL-L001), , |
| 300 | SV3-RNS-P0W-ME5495 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC SV3-RNS-PLW-015 (LINE NUMBERS RNS-PL-L005, -L029, -L080), |
| 301 | SV3-RNS-P0W-ME5496 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRICS SV3-RNS-PLW-018 & -019 (LINE NUMBER RNS-PL-L001), |
| 302 | SV3-RNS-P0W-ME5502 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC SV3-RNS-PLW-191 (LINE NUMBER RNS-PL-L018B), |
| 303 | SV3-RNS-P0W-ME5505 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC SV3-RNS-PLW-198 (LINE NUMBERS RNS-PL-L018B, -L066B), |
| 304 | SV3-PXS-P0W-ME2952 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-430 (LINE NUMBERS PXS-PL-L122A), , |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 305 | SV4-WLS-P0W-ME5973 | INSTALLATION OF SMALL BORE CA01 WLS PIPING (INCLUDES ISOMETRIC SV4-WLS-PLW-64P) |
| 306 | SV0-RWS-ERW-EL0633 | Installation of Electrical Underground Commodities for the (RWS) Raw Water System and the Tank Farm Pumphouse Bldg 315 |
| 307 | SV0-RWS-ERW-EL0678 | Installation of Electrical Commodities Cable Tray and Raceway (Conduit) for the RWS and Tank Farm Pump House Switchgear Bldg. 315 |
| 308 | SV0-ZBS-ERW-EL2419 | INSTALL ZBS DUCT BANKS NORTH OF TURBINE BLDG. - PHASE 2 |
| 309 | SV4-ME01-PLW-ME1181 | CONDENSER C-3RD EXTRACTION PIPING (EXTRACTION STEAM) |
| 310 | SV0-YFS-PLW-ME1090 | Fabricate and Install the Yard Fire Water line East & North of Building 307, West of Building 322 to trench 6 |
| 311 | SV3-2040-SSW-CV3299 | UNIT 3 TURBINE BUILDING SEQUENCE 8 HANDRAIL & STAIRS |
| 312 | SV3-2040-SSW-CV3300 | UNIT 3 TURBINE BUILDING SEQUENCE 9 HANDRAIL & STAIRS |
| 313 | SV3-PWS-PHW-ME4951 | ANNEX - PWS Piping Support - Iso 114, 134, 135, 192, 439, & 442 |
| 314 | SV4-CA20-S4W-CV6821 | CA20-32/33/74 INSTALLATION |
| 315 | SV4-CA20-S4W-CV6823 | CA20-33 TEMP. ATT. & CA20-32,33,74A,74B LEDGER ANGLES TEMP. ATT. |
| 316 | SV4-CA20-S4W-CV6830 | CA20-35 UNSATISFACTORY IRS/ N&DS/ E&DCRS AND LOOSE PARTS - STRUCTURAL |
| 317 | SV4-CA20-S4W-CV6961 | CA20-74A/74B TEMPORARY ATTACHMENTS - FLOOR |
| 318 | SV4-CA20-S5W-CV6896 | CA20-51 Unsat IRs/N&Ds/E&DCRs and LOOSE PARTS - Structural |
| 319 | SV4-CA20-S5W-CV6897 | CA20-51 Unsat IRs & N&Ds - Studs |
| 320 | SV3-PWS-P0W-ME6978 | INSTALLATION OF ANNEX BLDG PWS PIPING (ISOMETRICS SV3-PWS-PLW-150, 156, 157, 159, 179, 448, 454, 455, & 471) |
| 321 | SV3-PWS-PHW-ME6980 | Installation of Annex Bldg PWS Pipe Supports (Isometrics SV3-PWS-PLW-159, 179, 448). |
| 322 | SV0-MH90-MHW-RI1213 | HLD Block and Hook Temporary Support Frame |
| 323 | SV0-0000-XRW-CV0068 | Railroad Extension and Spur |
| 324 | SV4-1210-CCW-CV1814 | UNIT 4 NUCLEAR ISLAND AUXILIARY BUILDING CONCRETE PLACEMENT FOR EXERIOR WALLS FORM ELEVATION 66'-6" TO 82'-6" (WALL PLACEMENTS 1 THRU 8) |
| 325 | SV3-PXS-P0W-ME8638 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRICS# SV3-PXS-PLW-791 & 796 (LINE NUMBER PXS-PL-L161A, L161C & L164C) |
| 326 | SV3-CAS-PHW-ME6016 | INSTALLATION OF ANNEX BLDG CAS PIPE SUPPORTS (ISO SV3-CAS-PLW-20J, 20K, 20L, & 20M) |
| 327 | SV4-WLS-P0W-ME5975 | INSTALLATION OF SMALL BORE CA01 WLS PIPING (INCLUDE ISOMETRICS SV4-WLS-PLW-851, & -852 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 328 | SV4-WLS-P0W-ME6135 | INSTALLATION OF SMALL BORE CA01 WLS EMBEDDED PIPING (INCLUDE ISOMETRICS SV4-WLS-PLW-57B, 57C, & 57D) |
| 329 | SV3-4041-CRW-CV3184 | U3 ANNEX BUILDING AREA 1 CONCRETE REINFORCEMENT ELEVATION 100'-0" TO ELEVATION 117'-6" |
| 330 | SV0-0000-XCW-CV0413 | Settlement Monitoring of Nuclear Island |
| 331 | SV0-0000-XEW-CV0021 | Erosion Control for NOI 28 |
| 332 | SV0-0000-XGW-CV0368 | NOI 5 Excavation North & East of Nulcear Island #3 |
| 333 | SV3-1000-CCW-CV0297 | NUCLEAR ISLAND 3 CONCRETE |
| 334 | SV3-1200-MLW-CV1468 | CIVIL BLOCK-OUTS FOR MECHANICAL AND ELECTRICAL PENETRATIONS IN UNIT 3 AUX. BLDG. WALLS TO 82'-6" |
| 335 | SV3-4002-SSW-CV3906 | ANNEX BUILDING AREA 2 METAL DECKING AND GRATING INSTALLATION |
| 336 | SV3-CWS-XEW-CV0054 | GROUTING OF PHASE 1 CWS PIPE JOINTS (PCCP) AND FLOWABLE FILL PLACEMENT |
| 337 | SV4-CWS-CYW-CV0152 | PHASE 2 JOINT GROUTING AND FLOWABLE FILL |
| 338 | WCD 08-1246058001-1275-C-ERC-012 | Erosion Control - NOI 12 |
| 339 | SV3-4042-CEW-CV3180 | U3 ANNEX BUILDING AREA EMBEDDED ITEMS FROM ELEVATION 100'-0" TO 117'-6" |
| 340 | SV3-1220-CEW-CV1610 | AUXILIARY BUILDING, ELEVATION 82' 6" - 100' 0", CIVIL/ELECTRICAL/MECHANICAL BLOCK OUTS AND ASSOCIATED EMBEDMENT |
| 341 | SV3-1220-CRW-CV1701 | UNIT 3 AUXILIARY BUILDING REINFORCING STEEL FOR FLOORS AT EL. 82'-6" |
| 342 | SV3-CWS-PHW-ME2423 | FABRICATION AND INSTALLATION OF CWS PIPING SUPPORTS IN TURBINE ROOM 20309 FROM CWS HEADER TO CMS-ME-01A/B/C/D (ELEVATION 90FT TO 101FT) |
| 343 | SV3-DWS-P0W-ME6989 | INSTALLATION OF ANNEX BLDG DWS PIPING (ISOMETRIC SV3-DWS-PLW-203, -204, -237, -238) |
| 344 | SV0-MG01-MEW-ME6219 | CONSTRUCTION AIDES FOR TURBINE/GENERATOR ERECTION |
| 345 | SV4-PWS-P0W-ME2004 | INSTALLATION OF SMALL BORE PWS PIPNG (INCLUDES ISOMETRIC SV4-PWS-PLW-921, 924) |
| 346 | SV4-WLS-P0W-ME5976 | INSTALLATION OF SMALL BORE CA01 WLS EMBEDDED PIPING (INCLUDES ISOMETRIC SV4-WLS-PLW-57A) |
| 347 | SV3-WWS-P0W-ME6805 | INSTALLATION OF LARGE BORE WWS PIPING (INCLUDES SV3-WWS-PLW-326, 327) |
| 348 | SV3-PXS-P0W-ME2954 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-450 (LINE NUMBERS PXS-PL-L126A) |
| 349 | SV3-PXS-P0W-ME2962 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-01A (LINE NUMBERS PXS-PL-L113A) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 350 | SV0-0000-EGW-EL3915 | PERFORM INSTALLATION OF UNDERGROUND COMMODITIES (SV0 SITE STATION GROUNDING GRID) FOR GROUND GRID AREA K1100 |
| 351 | SV3-WLS-PHW-ME5874 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-WLS-PLW-511. |
| 352 | SV3-WLS-PHW-ME5873 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-WLS-PLW-510. |
| 353 | SV3-1220-CEW-CV1609 | U3 Auxiliary Building Embed Plates-Area 5 & 6 -EL 82'-6" Walls |
| 354 | SV4-WRS-P0W-ME1968 | INSTALLATION OF LARGE BORE WRS PIPING (INCLUDES ISOMETRICS SV4-WRS-PLW-59J, 59K, 59N, 59Q, 59U) |
| 355 | SV4-VCS-PHW-ME6183 | INSTALLATION OF VCS PIPING SUPPORTS SHOWN ON ISOMETRIC SV4-VCS-PLW-010. |
| 356 | SV3-VWS-P0W-ME4476 | FABRICATE AND INSTALL ANNEX CENTRAL CHILLED WATER (VWS) PIPING IAW (ISOMETRICS SV3-VWS-PLW-121, -122 -123, -131, -132, -133, -144, -147, -148) |
| 357 | SV3-RNS-P0W-ME5498 | Fabrication/Installation of Isometric SV3-RNS-PLW-182 (Line Numbers RNS-PL-L017 – L018B) |
| 358 | SV3-RNS-P0W-ME5503 | Fabrication/Installation of Isometric SV3-RNS-PLW-192 (Line Numbers RNS-PL-L018B, -L019B, -L067B) |
| 359 | SV4-1208-SCW-CV6996 | Course 3 Unit 4 Shield Building |
| 360 | SV3-0000-SSW-CV2420 | UNIT 3 TRANSFORMER FOUNDATION STRUCTURAL STEEL |
| 361 | SV4-ECS-CCW-CV6767 | UNIT 4 ECS DUCTBANK |
| 362 | SV3-1215-ERW-EL3169 | AUXILARY BUILDING UNIT 3, EL 66'-6", AREA 5, FABRICATE AND INSTALL TYPICAL CONDUIT SUPPORTS. |
| 363 | SV3-1240-EGW-EL6062 | INSTALL GROUNDING GRID AND FLOOR PLATES FOR 117'-6" SLAB AREAS 1, 2 & 3 |
| 364 | SV3-2000-PHW-ME6770 | INSTALLATION OF SUPPORTS FOR TEMPORARY FIRE PROTECTION SYSTEM STANDPIPE |
| 365 | SV3-PWS-P0W-ME4950 | ANNEX - PWS PIPING - ISO 114, 134, 135, 192, 439, & 442 |
| 366 | SV4-WLS-P0W-ME6144 | INSTALLATION OF SMALL BORE CA03 WLS EMBEDDED PIPING (INCLUDE ISOMETRICS SV4-WLS-PLW-57Z, & -64R) |
| 367 | SV3-PWS-PHW-ME5278 | FABRICATION/INSTALLATION OF SMALL BORE PWS PIPING SUPPORTS FOR ISOMETRIC DRAWING SV3-PWS-PLW-954, 955, 956, 957 |
| 368 | SV3-CAS-PHW-ME0764 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWINGS (SV3-CAS-PLW-375, 42A, 42B) |
| 369 | SV0-YFS-PLW-ME1088 | FABRICATE AND INSTALL THE YARD FIRE WATER LINE FROM BUILDING 304 TO BUILDING 302 AND HYDRANT H-27. |
| 370 | SV0-PWS-PLW-ME1083 | FABRICATE AND INSTALL POTABLE WATER PIPING BETWEEN BUILDING 304 AND BUILDINGS 302 AND 303. |
| 371 | SV0-YFS-PLW-ME1089 | FABRICATE AND INSTALL THE YARD FIRE WATER LINE FROM BUILDING 302 TO BUILDINGS 303, 305 AND 307. |
| 372 | SV4-1208-SCW-CV6998 | Course 5 Unit 3 Shield Building |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 373 | SV4-1208-SCW-CV6999 | Course 6 Unit 3 Shield Building |
| 374 | SV4-1208-SCW-CV7001 | Course 8 Unit 3 Shield Building |
| 375 | SV4-1208-SCW-CV7007 | Course 14 Unit 3 Shield Building |
| 376 | SV0-RWS-CCW-CV0718 | Install RWS Manholes and Ductbank |
| 377 | SV3-1010-CRW-CV0630 | INSTALLATION OF NUCLEAR ISLAND BASEMAT REINFORCEMENT BELOW CONTAINMENT VESSEL |
| 378 | SV3-2000-SUW-CV0181 | Assembly and erection of CH82 module in Area 111 |
| 379 | SV3-RNS-P0W-ME5497 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC SV3-RNS-PLW-021 (LINE NUMBERS RNS-PL-L040, -L061, -L062), |
| 380 | SV3-2040-SUW-CV1187 | Turbine Building Structural Steel Sequence 9 |
| 381 | SV3-2030-CWS-ME1355 | Installation of (2) 120" CWS Butterfly Valves (Condenser Return) Piping and Components from Condenser C |
| 382 | SV3-RNS-P0W-ME5499 | ASME SECTION III – FABRICATION/INSTALLATION OF ISOMETRIC SV3-RNS-PLW-184 (LINE NUMBERS RNS-PL-L019A, - L067A) |
| 383 | SV3-RNS-P0W-ME5500 | ASME SECTION III – FABRICATION/INSTALLATION OF ISOMETRIC SV3-RNS-PLW-186 (LINE NUMBERS RNS-PL-L020, - L068) |
| 384 | SV4-WLS-P0W-ME6139 | INSTALLATION OF SMALL BORE CA02 WLS EMBEDDED PIPING (INCLUDE ISOMETRICS SV4-WLS-PLW-57L, -57M, -57N, & -569) |
| 385 | SV4-WLS-P0W-ME6142 | INSTALLATION OF SMALL BORE CA03 WLS EMBEDDED PIPING (INCLUDE ISOMETRICS SV4-WLS-PLW-57V, -57W, & -57X) |
| 386 | SV3-DWS-PHW-ME6354 | INSTALLATION OF ANNEX BLDG DWS PIPE SUPPORTS (ISOMETRICS SV3-DWS-PLW-245 & -246) |
| 387 | SV3-1120-ERW-EL3371 | FABRICATION AND INSTALLATION OF DESIGN ROUTED CONDUIT SUPPORTS IN ROOM 11201 AT ELEVATION 84'-6" |
| 388 | SV3-1120-ERW-EL3370 | FABRICATION AND INSTALLATION OF DESIGN ROUTED CONDUIT SUPPORTS IN ROOM 11201 AT ELEVATION 84'-6" |
| 389 | SV3-1120-ERW-EL3369 | FABRICATION AND INSTALLATION OF DESIGN ROUTED CONDUIT SUPPORTS IN ROOM 11201 AT ELEVATION 84'-6" |
| 390 | SV3-1120-ERW-EL2741 | FABRICATION AND INSTALLATION OF CABLE TRAY SUPPORTS IN ROOM 11204 AT ELEVATION 84'-6" TO 107'2" |
| 391 | SV3-1120-ERW-EL2847 | FABRICATION AND INSTALLATION OF CABLE TRAY SUPPORTS IN ROOM 11204 AT ELEVATION 84'6" TO 107'2" |
| 392 | SV3-1120-ERW-EL3522 | FABRICATION AND INSTALLATION OF DESIGN ROUTED CONDUIT SUPPORTS IN ROOM 11204 AT ELEVATION 84' 6" |
| 393 | SV3-2040-SUW-CV1188 | Turbine Building Structural Steel Framing Sequence 10 |
| 394 | SV3-4034-CRW-CV2622 | ANNEX AREA 4 FOUNDATION REINFORCEMENT |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 395 | SV3-1220-CCW-CV3385 | UNIT 3 AUXILIARY BUILDING FLOORS AREAS 1 AND 2- CONCRETE PLACEMENT AT ELEV. 82' 6"(SLAB PLACEMENT #1 THRU #7 |
| 396 | SV3-2040-SSW-CV3302 | UNIT 3 TURBINE BUILDING SEQUENCE 11 HANDRAIL & STAIRS |
| 397 | SV0-ZFS-CCW-CV2057 | ZFS DUCTBANK |
| 398 | SV0-SES-CCW-CV2055 | SES Ductbank |
| 399 | SV3-WRS-P0W-ME2347 | ANNEX BUILDING - ELEV 100 WRS PIPING PACKAGE #1 |
| 400 | SV3-WWS-P0W-ME6696 | FABRICATION AND INSTALLATION OF WWS PIPE & DRAIN HUBS ELEVATION 140' |
| 401 | SV0-869-XVW-CV7066 | West Vehicle Barrier Ditch |
| 402 | SV4-2040-SSW-CV1827 | TURBINE BUILDING STRUCTURAL STEEL SEQUENCE 8 |
| 403 | SV3-1130-SLW-CV7077 | Upender Pit |
| 404 | SV3-PXS-P0W-ME6163 | ASME SECTION III – FABRICATION/INSTALLATION OF ISOMETRICS #SV3-PXS-PLW-300 (LINE NUMBER PXS-PL-L153) |
| 405 | SV3-1213-ERW-EL3678 | FABRICATE AND INSTALL FIELD ROUTE TYPICAL CONDUIT SUPPORT C13 FOR AUX BUILDING (AREAS 3 & 4) EL 66'6" TO 82'-6" |
| 406 | SV3-1213-ERW-EL3679 | FABRICATE AND INSTALL FIELD ROUTED TYPICAL CONDUIT SUPPORT C14 FOR AUX BUILDING (AREAS 3 & 4) EL 66'-6" TO 82'-6" |
| 407 | SV3-1215-ERW-EL3687 | FABRICATE AND INSTALL FIELD ROUTED TYPICAL CONDUIT SUPPORT C31 FOR AUX BUILDING (AREAS 5 &6) EL 66'-6" TO 82'-6" |
| 408 | SV4-2040-SSW-CV3971 | UNIT 4 TURBINE BUILDING SEQUENCE 8 HANDRAIL & STAIRS |
| 409 | SV4-2040-SSW-CV3973 | UNIT 4 TURBINE BUILDING SEQUENCE 9 HANDRAIL & STAIRS |
| 410 | SV3-PXS-P0W-ME2965 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC # SV3-PXS-PLW-01D (LINE NUMBERS PXS-PL-L113A) |
| 411 | SV3-1213-ERW-EL1627 | AUXILIARY BUILDING UNIT 3, EL 66'-6", AREA 3, INSTALL SCHEDULED CONDUITS AND SCHEDULED PULL BOXES. |
| 412 | SV3-PXS-P0W-ME2969 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC # SV3-PXS-PLW-01Z (LINE NUMBERS PXS-PL-L108, L115, L119, L113A) |
| 413 | SV3-PXS-P0W-ME2964 | SV3-PXS-P0W-ME2964 |
| 414 | SV3-PXS-P0W-ME3236 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC # SV3-PXS-PLW-023 (LINE NUMBERS PXS-PL-L029B) |
| 415 | SV3-PXS-P0W-ME2950 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC # SV3-PXS-PLW-330 (LINE NUMBERS PXS-PL-L057A) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 416 | SV3-PXS-P0W-ME2949 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC # SV3-PXS-PLW-320 (LINE NUMBERS PXS-PL-L056A) |
| 417 | SV4-2040-SSW-CV1828 | TURBINE BUILDING STRUCTURAL STEEL SEQUENCE 9 |
| 418 | SV3-1220-CEW-CV1603 | AUXILIARY BUILDING EMBEDS AND ANCHOR BOLTS - ELEVATION 82 FT - 6 IN SLAB - AREAS 1 AND 2 |
| 419 | SV3-2050-CCW-CV0126 | 141'-3" to 158'-7" Elevated Slabs Unit 3 Turbine |
| 420 | SV3-WWS-THW-ME7172 | Hydro Test Unit 3 Waste Water System Steel Piping |
| 421 | SV4-WLS-P0W-ME6136 | INSTALLION OF SMALL BORE CA01 WLS EMBEDDED PIPING (INCLUDE ISOMETRICS SV4-WLS-PLW-57E) |
| 422 | SV3-MS33-MEW-ME4613 | INSTALLATION OF GLAND STEAM CONDENSER (GSS-ME-01) ON 120' |
| 423 | SV3-CPS-P0W-ME3595 | INSTALLATION AND FABRICATION OF CONDENSATE POLISHING SYSTEM (CPS) PIPING FOR ISOMETRICS |
| 424 | SV3-1211-ERW-EL3776 | Install Design Routed Conduit and Conduit Supports in Battery Room “B”, Room 12104. |
| 425 | SV3-1211-ERW-EL3777 | Install Design Routed Conduit and Conduit Supports in Battery Room “D”, Room 12105 |
| 426 | SV3-DOS-P0W-ME2467 | FABRICATE & INSTALL DIESEL FUEL OIL PIPING NORTH OF THE UNIT 3 ANNEX TO DIESEL FUEL OIL TANKS |
| 427 | SV3-2040-CCW-CV5190 | UNIT 3 TURBINE BUILDING MISCELLANEOUS GROUTING AT ELEVATION 120'-6" |
| 428 | SV4-WLS-P0W-ME6141 | INSTALLATION OF SMALL BORE WLS EMBEDDED PIPING (INCLUDE ISOMETRICS SV4-WLS-PLW-57T & 57U) |
| 429 | SV3-WWS-P0W-ME6701 | FABRICATION AND INSTALLATION OF WASTE WATER SYSTEM (WWS) PIPE & DRAIN HUBS ELEVATION 140' |
| 430 | SV3-PXS-P0W-ME7398 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC SV3-PXS-PLW-223 (LINE NUMBER PXS-PL-L142B) |
| 431 | SV3-2033-SHW-EL7390 | ELECTRICAL CABLE TRAY AND SUPPORTS MILESTONE INSTALLATION FOR THE TURBINE BUILDING AT ELEVATION 100'-0" IN AREA 3 |
| 432 | SV3-WRS-P0W-ME4431 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES ISOMETRICS SV3-WRS-PLW-80D |
| 433 | SV3-WRS-P0W-ME4432 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES ISOMETRICS SV3-WRS-PLW-80E |
| 434 | SV3-WRS-P0W-ME4427 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES ISOMETRICS SV3-WRS-PLW-805, 806, 80M, 80Z, 862, 863 AND 864) |
| 435 | SV3-1240-EGW-EL6063 | INSTALL GROUNDING GRID AND FLOOR PLATES FOR 117'-6' SLAB AREAS 4, 5 & 6 |
| 436 | SV0-ZFS-ERW-EL5909 | INSTALLATION OF (ZFS) COMMUNICATIONS SYSTEM ELECT DUCT BANK FOR PHASE 10 |
| 437 | SV0-SES-ERW-EL5491 | INSTALL CONDUIT IN SES DUCT BANK/TRENCH FOR SECURITY LOCATED BETWEEN SITE GRID M1401-L1502 PHASE 10 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 438 | SV3-1210-ERW-EL3160 | AUXILIARY BUILDING UNIT 3, EL 66'-6", AREA 2, FABRICATE AND INSTALL DESIGNED CONDUIT SUPPORTS |
| 439 | SV0-SES-ERW-EL4466 | INSTALL CONDUIT IN SES DUCT BANK/TRENCH FOR SECURITY LOCATED BETWEEN SITE GRID K1402-K1202 PHASE 2AND 7 |
| 440 | SV3-2060-SUW-CV0193 | Turbine Building Structural Steel Framing Sequence 12 |
| 441 | SV4-WLS-P0W-ME6138 | Installation of Small Bore CA01 WLS Embedded Piping (Include Isometrics SV4-WLS-PLW-57J, & -57K) |
| 442 | SV3-1208-SCW-CV7395 | TRAINING ADMIN PACKAGE FOR CBIS |
| 443 | SV4-WLS-P0W-ME6241 | INSTALLATION OF SMALL BORE CA03 WLS EMBEDDED PIPING (INCLUDE ISOMETRICS SV4-WLS-PLW-647, -648, -649, -64A, -64B, -64C, & -64D) |
| 444 | SV4-WLS-P0W-ME6143 | INSTALLATION OF SMALL BORE CA03 WLS EMBEDDED PIPING(INCLUDE ISOMETRICS SV4-WLS-PLW-57Y, -640, & -641) |
| 445 | SV4-WWS-PHW-ME5005 | INSTALLATION OF LARGE BORE WWS PIPING SUPPORTS (INCLUDES ISOMETRICS: SV4-WWS-PLW-014) |
| 446 | SV3-SFS-P0W-ME6691 | ASME SECTION III – FABRICATION/INSTALLATION OF ISOMETRIC SV3-SFS-PLW-783, -784, -785 (LINE NUMBER SFS-PL-L036) |
| 447 | SV3-WRS-P0W-ME3368 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES ISOMETRIC SV3-WRS-PLW-831) |
| 448 | SV3-KB21-KBW-ME7474 | INSTALLATION OF KB21 COMPONENTS |
| 449 | SV3-WLS-THW-ME7475 | HYDRO TESTING OF KB21 WLS PIPING |
| 450 | SV4-CAS-THW-ME7388 | HYDRO-TEST CAS COMPRESSED AIR SYSTEM PIPING IN PHASE 7, EAST SIDE OF U4 TB. |
| 451 | SV4-HDS-P0W-ME5461 | INSTALLATION AND FABRICATION OF HEATER DRAIN SYSTEM (HDS) PIPING |
| 452 | SV3-PSS-PHW-ME7506 | Fabrication/Installation of Pipe supports for Isometric SV3-PSS-PLW-716 |
| 453 | SV3-PSS-PHW-ME7507 | Fabrication/Installation of Pipe supports for Isometric SV3-PSS-PLW-715 |
| 454 | SV3-PSS-PHW-ME7508 | INSTALLATION OF TUBE CLAMPS FOR ISOMETRIC DRAWING SV3-PSS-PLW-714 |
| 455 | SV3-PSS-PHW-ME7509 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-PSS-PLW-713 |
| 456 | SV4-PXS-P0W-ME7533 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC# SV4-PXS-PLW-018 (LINE NUMBERS PXS-PL-L112A), , |
| 457 | SV3-CPS-PHW-ME3594 | INSTALLATION OF CPS PIPING SUPPORTS FOR ISOMETRICS |
| 458 | SV4-ML05-MLW-ME7566 | Installation of 100’0 Wall Penetrations Area 1 |
| 459 | SV4-ML05-MLW-ME7567 | Installation of 100’0 Wall Penetrations 3, 4, 5 |
| 460 | SV4-ML05-MLW-ME7568 | Installation of 100’0 Wall Penetrations Area 6 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 461 | SV4-CES-P0W-ME7577 | Installation of CES piping (Portion 2) |
| 462 | SV4-CES-PHW-ME7578 | Installation of CES pipe supports (Portion 1) |
| 463 | SV4-CES-PHW-ME7579 | INSTALLATION OF CES PIPE SUPPORTS (PORTION 6) |
| 464 | SV3-FPS-MPW-ME7581 | Install Unit 3 Diesel Fire Pump Package SV3-FPS-MS-01B |
| 465 | SV3-CPS-PHW-ME3596 | INSTALLATION AND FABRICATION OF CONSENSATE POLISHING SYSTEM (CPS) |
| 466 | SV3-FPS-PLW-ME4857 | INITIAL ENERGIZATION - INSTALLATION OF ANNEX FIRE PROTECTION SYSTEM (FPS) PIPING IAW (ISOMETRICS SV3-FPS-PLW-332, 587) |
| 467 | SV3-WRS-P0W-ME4425 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES ISOMETRICS SV3-WRS-PLW-803, 804, 80N, 80P, 860, 861) |
| 468 | SV4-WLS-P0W-ME6242 | INSTALLATION OF SMALL BORE CA03 WLS EMBEDDED PIPING (INCLUDE ISOMETRICS SV4-WLS-PLW-64E, -64F, -64G, -64H, -64I, & -64J) |
| 469 | SV4-WLS-P0W-ME6240 | INSTALLATION OF SMALL BORE CA03 WLS EMBEDDED PIPING (INCLUDE ISOMETRICS SV4-WLS-PLW-642, 643, 644, 645, 646) |
| 470 | SV3-WWS-PHW-ME4637 | INSTALLATION OF TURBINE BUILDING WWS PIPING SUPPORTS (INCLUDES ISOMETRICS SV3-WWS-PLW-043, 044, 045, 046, 047, 048, 110, 111, 112, 113, 114, 115 & 116) |
| 471 | SV3-SFS-P0W-ME7667 | INSTALLATION OF SFS-PLW-650, 660, 665 AND 667 (THIS PACKAGE WILL INCLUDE TIE IN WELDS TO KB12 MODULE PIPING SFS-PLW-088, 089 AND WLS-PLW-60F, 60G) |
| 472 | SV4-RNS-MPW-ME7593 | INSTALLATION OF RESIDUAL HEAT REMOVAL PUMP A (RNS-MP-01A) AND STAND (RNS-MZ-12A) |
| 473 | SV4-RNS-MPW-ME7594 | INSTALLATION OF RESIDUAL HEAT REMOVAL PUMP B (RNS-MP-01B) AND STAND (RNS-MZ-12B) |
| 474 | SV4-RNS-MPW-ME7595 | Disassembly of Residual Heat Removal Pump A |
| 475 | SV4-RNS-MPW-ME7596 | Installation of Residual Heat Removal Pump B |
| 476 | SV4-WWS-MTW-ME7669 | Install Unit 4 Transformers Area Sump SV4-WWS-MTW-010 |
| 477 | SV4-WWS-P0W-ME7670 | Fabricate and install the Waste Water piping to the Unit 4 Transformers Area Sump SV4-WWS-MTW-010 |
| 478 | SV3-2035-SHW-EL7592 | Electrical Cable Tray Supplemental Steel Installation in the Turbine Building, Elevation 100'-0", Area 5 from Columns 13.1 to 16 & I.2 to K.2 |
| 479 | SV4-HDS-P0W-ME5462 | INSTALLATION AND FABRICATION OF HEATER DRAIN SYSTEM(HDS) PIPING |
| 480 | SV3-CPS-P0W-ME3591 | INSTALLATION OF CPS PIPING |
| 481 | SV3-0000-ELW-EL7683 | Installation of Cable for Unit 3 Standard Plant Yard Transformer Area Lighting |
| 482 | SV4-ML05-MLW-ME7644 | INSTALL CA01 ASME PROCESS PIPE PENETRATION SV4-11300-ML-P47 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 483 | SV4-ML05-MLW-ME7645 | INSTALL CA01 ASME PROCESS PIPE PENETRATION SV4-11300-ML-P48 |
| 484 | SV4-ML05-MLW-ME7646 | INSTALL CA01 ASME PROCESS PIPE PENETRATION SV4-11300-ML-P49 |
| 485 | SV4-ML05-MLW-ME7647 | INSTALL CA01 ASME PROCESS PIPE PENETRATION SV4-11300-ML-P50 |
| 486 | SV4-ML05-MLW-ME7648 | INSTALL CA01 ASME PROCESS PIPE PENETRATION SV4-11302-ML-P09 |
| 487 | SV4-ML05-MLW-ME7649 | INSTALL CA01 ASME PROCESS PIPE PENETRATION SV4-11302-ML-P10 |
| 488 | SV4-ML05-MLW-ME7650 | INSTALL CA01 ASME PROCESS PIPE PENETRATION SV4-11303-ML-P13 |
| 489 | SV4-ML05-MLW-ME7652 | INSTALL CA01 ASME PROCESS PIPE PENETRATION SV4-11303-ML-P15 |
| 490 | SV4-ML05-MLW-ME7653 | INSTALL CA01 ASME PROCESS PIPE PENETRATION SV4-11303-ML-P16 |
| 491 | SV4-ML05-MLW-ME7654 | INSTALL CA01 ASME PROCESS PIPE PENETRATION SV4-11400-ML-P12 |
| 492 | SV4-ML05-MLW-ME7655 | INSTALL CA01 ASME PROCESS PIPE PENETRATION SV4-11400-ML-P13 |
| 493 | SV4-ML05-MLW-ME7656 | Install CA01 Penetration SV4-11501-ML-P01 |
| 494 | SV4-ML05-MLW-ME7657 | Install CA01 ASME Process Pipe Penetration SV4-11501-ML-P02 |
| 495 | SV4-ML05-MLW-ME7659 | INSTALL CA01 ASME PROCESS PIPE PENETRATION SV4-11504-ML-P01 |
| 496 | SV4-ML05-MLW-ME7660 | Install CA01 AMSE Pipe Penetration SV4-11504-ML-P02 |
| 497 | SV4-ML05-MLW-ME7661 | INSTALL CA01 ASME PROCESS PIPE PENETRATION |
| 498 | SV4-ML05-MLW-ME7663 | INSTALLATION OF CA01 DVI PENETRATION SV4-11205-ML-P01 |
| 499 | SV4-ML05-MLW-ME7664 | CA01 INSTALLATION OF CA01 DVI PENETRATION SV4-11205-ML-P03 |
| 500 | SV4-WLS-P0W-ME6137 | INSTALLATION OF SMALL BORE CA01 WLS EMBEDDED PIPING (INCLUDE ISOMETRICS SV4-WLS-PLW-57F, 57G, 57H, 567, & 568) |
| 501 | SV3-WWS-P0W-ME6706 | FABRICATION AND INSTALLATION OF WWS PIPE & DRAIN HUBS ELEVATION 140' |
| 502 | SV3-2101-CRW-CV7315 | UNIT 3 TURBINE FIRST BAY WALLS, WALL TO FLOOR MECHANICAL COUPLERS AIR 117-'6" |
| 503 | SV4-WWS-PHW-ME5004 | INSTALLATION OF LARGE BORE WWS PIPING SUPPORTS (INCLUDES ISOMETRICS SV4-WWS-PLW-01D) |
| 504 | SV3-CPS-PHW-ME3592 | FABRICATION AND INSTALLATION OF CONDENSATE POLISHER SYSTEM (CPS) PIPING |
| 505 | SV4-KB12-KBW-ME1881 | Installation of Module KB12 |
| 506 | SV4-KB11-KBW-ME1880 | Installation of Module KB11 |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 507 | SV3-DWS-PHW-ME6673 | INSTALLATION OF ANNEX BLDG DWS PIPE SUPPORTS (ISOMETRICS SV3-DWS-PLW-243, 244) |
| 508 | SV3-PWS-PHW-ME7051 | INSTALLATION OF ANNEX BLDG PWS SUPPORTS (ISOMETRICS SV3-PWS-PLW-113 & SV3-PWS-PLW-155) |
| 509 | SV4-ME01-PLW-ME7831 | Installation of Vacuum Piping for Condenser B |
| 510 | SV4-ME01-PLW-ME7832 | INSTALLATION OF VACUUM PIPING FOR CONDENSER C |
| 511 | SV0-863-P0W-ME7836 | FABRICATE AND INSTALL UNDERGROUND PIPING UTILITIES POTABLE WATER, SANITARY SEWER, FIRE SUPPRESSION FOR BUILDING 304 |
| 512 | SV3-2052-SHW-EL7838 | Electrical Cable Tray Supplemental Steel Installation in the Turbine Building, Elevation 141'-3", Area 2 from Columns 17 to 18 & P.2 to R |
| 513 | SV3-2053-SHW-EL7839 | Electrical Cable Tray Supplemental Steel Installation in the Turbine Building, Elevation 141'-3", Area 3 from Columns 18 to 19 & P.2 to R |
| 514 | SV3-2053-SHW-EL7842 | Electrical Cable Tray Supplemental Steel Installation in the Turbine Building, Elevation 141'-3", Area 3 from Columns 18 to 19 & P.1 to P.2 |
| 515 | SV3-2052-SHW-EL7843 | Electrical Cable Tray Supplemental Steel Installation in the Turbine Building, Elevation 141'-3", Area 2 rom Columns 16 to 18 & L.5 to P.2 |
| 516 | SV3-2053-SHW-EL7844 | Electrical Cable Tray Supplemental Steel Installation in the Turbine Building, Elevation 141'-3", Area 3 from Columns 18 to 19 & L.5 to P.1 |
| 517 | SV4-HDS-P0W-ME5458 | INSTALLATION AND FABRICATION OF HEATER DRAINSYSTEM(HDS) PIPING |
| 518 | SV0-863-ERW-EL7706 | INSTALL UNDERGROUND CONDUIT FOR 304 BUILDING |
| 519 | SV3-4040-EGW-EL4375 | PERFORM INSTALLATION OF UNDERGROUND COMMODITIES (EGS - GROUNDING) FOR THE ANNEX BLDG, AREA 2, ELEV 117' - BETWEEN COLUMN LINES 4 & 9 |
| 520 | SV3-CDS-PHW-ME2309 | INSTALLATION OF CDS PIPING SUPPORTS |
| 521 | SV3-MS09-MEW-ME3566 | INSTALLATION OF NON-REGENERABLE MIXED BED (DTS-MS-05A/B) |
| 522 | SV3-ME2A-MEW-ME3691 | INSTALLATION OF BDS-ME-01A&B (SG BLOWDOWN) ON ELEV 100' |
| 523 | SV3-WLS-PHW-ME3870 | FABRICATION/INSTALLATION OF WLS PIPING SUPPORTS FOR ISOMETRICS: SV3-WLS-PLW-536, -53A |
| 524 | SV3-CPS-PHW-ME3600 | INSTALLATION AND FABRICATION OF CONDENSATE POLISHING SYSTEM(CPS) PIPING SUPPORTS |
| 525 | SV3-CDS-PHW-ME4910 | FABRICATION AND INSTALLATION OF CDS PIPING SUPPORTS FOR ISOMETRICS SV3-CDS-PLW-70F, 70G, 70H, 70J |
| 526 | SV3-CPS-P0W-ME3599 | INSTALLATION AND FABRICATION OF CONDENSATE POLISHING SYSTEM (CES) PIPING |
| 527 | SV0-0000-VNY-RI7862 | Mammoet Documentation for Transport |
| 528 | SV3-WWS-PHW-ME7860 | FABRICATE AND INSTALL THE PIPE SUPPORTS FOR UNIT 3 WWS PIPING IN VALVE BOXES SV3-WWS-MY-Y04A AND SV3-WWS-MY-Y04B. |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 529 | SV4-WGS-ITW-ME7803 | GASEOUS RADWASTE SYSTEM (WGS) ITAAC FUNCTIONAL ARRANGEMENT WALKDOWN |
| 530 | SV4-2040-SSW-CV3974 | UNIT 4 TURBINE BUILDING SEQUENCE 9 DECKING AND GRATING |
| 531 | SV3-1130-CCW-CV3399 | U3 INTERIOR CV PLACEMENT, CURING AND REPAIR OF CONCRETE FROM ELEV 83'-0" |
| 532 | SV3-PWS-P0W-ME7861 | INSTALLATION OF PWS PIPING ISOMETRICS SV3-PWS-PLW-584, 585, 587, AND 588., NEED VENDOR TECH MANUAL |
| 533 | SV3-2036-SHW-EL6798 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE TURBINE BUILDING, ELEVATION 100'-0", AREA6 FROM COLUMNS 16 TO 18 & I.2 TO K.1 |
| 534 | SV4-HDS-P0W-ME5460 | INSTALLATION AND FABRICATION OF HEATER DRAINSYSTEM(HDS) PIPING |
| 535 | SV3-1212-ERW-EL3774 | Install Design Routed Conduit and Conduit Supports in Battery Room “C”, Room 12102 |
| 536 | SV3-2039-SHW-EL6799 | Electrical Cable Tray Supplemental Steel Installation in the Turbine Building, Elevation 100’-0”, Area 9 from Columns 18 to 19 & H.05 to I.2 |
| 537 | SV3-KB12-KBW-ME8002 | COMPLETE KB12 MODULE FABRICATION POST MODULE INSTALLATION |
| 538 | SV3-1212-ERW-EL3775 | INSTALL DESIGN ROUTED CONDUIT AND CONDUIT SUPPORTS IN 'SPARE' BATTERY ROOM 12103 |
| 539 | SV3-1212-ERW-EL3773 | INSTALL DESIGN ROUTED CONDUIT AND CONDUIT SUPPORTS IN BATTERY ROOM "A", ROOM 12101 |
| 540 | SV4-1220-SSW-CV4782 | UNIT 4 NUCLEAR ISLAND AUXILIARY BUILDING AREAS 3 & 4 STRUCTURAL STEEL FOR ELEVATION 82'-6" |
| 541 | SV4-2040-SSW-CV3972 | UNTI 4 TURBINE BUILDING SEQUENCE 8 DECKING AND GRATING |
| 542 | SV3-PV71-MEW-ME6246 | PRE-INSTALLATION WELDING OF MAIN STOP VALVE/CONTROL VALVE EQUALIZERS |
| 543 | SV3-CWS-PHW-ME2522 | INSTALLATION OF PIPE SUPPORTS FOR CWS SYSTEM |
| 544 | SV3-WWS-P0W-ME6699 | INSTALLATION AND FABRICATION OF WAST WATER SYSTEM (WWS) PIPING |
| 545 | SV4-ME2A-MEW-ME7421 | INSTALLATION OF BDS-ME-01A&B (SG BLOWDOWN) ON ELEV 100' |
| 546 | SV3-WWS-P0W-ME7985 | FABRICATION AND INSTALLATION OF WWS PIPE AND DRAIN HUBS ELEVATION 158’ |
| 547 | SV3-WWS-P0W-ME7987 | FABRICATION AND INSTALLATION OF WWS PIPE AND DRAIN HUBS ELEVATION 170' |
| 548 | SV3-WWS-P0W-ME7989 | FABRICATION AND INSTALLATION OF WWS PIPE AND DRAIN HUBS ELEVATION 166’ |
| 549 | SV3-WWS-P0W-ME7991 | FABRICATION AND INSTALLATION OF WWS PIPE AND DRAIN HUBS ELEVATION 170’ |
| 550 | SV3-WWS-PHW-ME7992 | FABRICATION AND INSTALLATION OF WWS PIPING SUPPORTS ELEVATION 170¿ |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 551 | SV3-WWS-P0W-ME7993 | FABRICATION AND INSTALLATION OF WWS PIPE AND DRAIN HUBS ELEVATION 170’ |
| 552 | SV3-WWS-P0W-ME7995 | FABRICATION AND INSTALLATION OF WWS PIPE AND DRAIN HUBS ELEVATION 170’ |
| 553 | SV3-WWS-P0W-ME7997 | FABRICATION AND INSTALLATION OF WWS PIPE AND DRAIN HUBS ELEVATION 170’ |
| 554 | SV3-WWS-P0W-ME7999 | FABRICATION AND INSTALLATION OF WWS PIPE AND DRAIN HUBS ELEVATION 200¿ |
| 555 | SV3-FPS-PHW-ME4310 | FABRICATION / INSTALLATION OF PIPE SUPPORTS FOR ISOMETRICS SV3-FPS-PLW-821, 827, & 829 |
| 556 | SV3-WLS-PHW-ME3871 | FABRICATION/INSTALLATION OF WLS PIPING SUPPORTS FOR ISOMETRICS: SV3-WLS-PLW-537, -538 |
| 557 | SV4-PSS-P0W-ME1999 | INSTALLATION OF PSS PIPING (INCLUDES ISO SV4-PSS-PLW-700, 701) |
| 558 | SV4-CWS-P0W-ME5456 | INSTALLATION OF CWS PIPING AUTOMATIC BACKWASH STRAINERS (CWS-PY-S01A/B/C) TO WWS COLLECTION BASIN (WWS-PY-D501) |
| 559 | SV3-MS22-MEW-ME3690 | INSTALL BDS-MS-01A/B, STEAM GENERATOR BLOWDOWN RADIATION MONITOR EDI AND ASSOCIATED COMPONENTS |
| 560 | SV3-2034-SHW-EL6795 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE TURBINE BUILDING ELEV 100' AREA 4 FROM COLUMNS 12.1 TO 13.1 & I2 TO K.1 |
| 561 | SV4-CDS-PHW-ME3231 | INSTALLATION OF PIPE SUPPORTS FOR PIPING PACKAGE SV4-CDS-P0W-ME3230 |
| 562 | SV4-CWS-P0W-ME7143 | INSTALLATION AND FABRICATION OF CIRCULATING WATER SYSTEM(CWS) PIPING |
| 563 | SV4-WLS-P0W-ME6170 | UNIT 4 WLS S/S PIPING FROM THE WLS/WWS TIE-IN MANHOLE SOUTHWARD HALFWAY THROUGH THE FINAL PHASE |
| 564 | SV4-VWS-P0W-ME7149 | INSTALLATION AND FABRICATION OF CENTRAL CHILLED WATER (VWS) SYSTEM PIPING |
| 565 | SV4-HDS-P0W-ME5459 | (BLANK) |
| 566 | SV4-4033-CCW-CV8105 | Annex Area 3 Embeds, Formwork & Concrete to Elevation 100'-00" |
| 567 | SV4-4032-CCW-CV8102 | Unit 4 Annex Area 2 Embeds, Formwork & Concrete to Elevation 100'-00" |
| 568 | SV4-4032-CRW-CV8100 | Unit 4 Annex Area 2 Reinforcement to Elevation 100'-00" |
| 569 | SV4-4031-CCW-CV8099 | Annex Area 1 Embeds, Formwork & Concrete to Elevation 100'-00" |
| 570 | SV3-CA20-ERW-EL8053 | Install Scheduled Field routed conduit in "CHEMICAL WASTE TANK ROOM" (12264) |
| 571 | SV3-CA20-ERW-EL8054 | Install Scheduled Field routed conduit in "WASTE MONITOR TANK ROOM C" (12265) |
| 572 | SV3-CA20-ERW-EL8055 | Install Scheduled Field routed conduit in "WASTE HOLDUP TANK ROOM A" (12166) |
| 573 | SV3-CA20-ERW-EL8056 | Install Scheduled Field routed conduit in "WASTE HOLDUP TANK ROOM B" (12167) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 574 | SV3-CA20-ERW-EL8057 | Install Scheduled Field routed conduit in "VESTIBULE")(12168), "CORRIDOR"(12169), and WLS PUMP ROOM"(12268) |
| 575 | SV3-CA20-ERW-EL8058 | Install Scheduled Field routed conduit in "PIPING VALVE ROOM"(12262) and "PIPE CHASE" (12269) |
| 576 | SV3-CA20-ERW-EL8059 | Install Scheduled Field routed conduit in "WASTE MONITOR TANK ROOM B" (12365) |
| 577 | SV3-CA20-ERW-EL8060 | Install Scheduled Field routed conduit in "WASTE MONITOR TANK ROOM A" (12363) |
| 578 | SV4-WWS-P0W-ME5468 | WASTE WATER SYSTEM FROM SUMP C TO PY D501 |
| 579 | SV4-CWS-P0W-ME7145 | CIRCULATING WATER SYSTEM, CONDENSER VENTS AND DRAINS |
| 580 | SV4-CDS-P0W-ME7113 | INSTALLATION OF CDS PIPING FOR 82'9" (PORTION 3) |
| 581 | SV4-WWS-P0W-ME5466 | UNIT 4 TURBINE WASTE WATER SYSTEM |
| 582 | SV4-4031-CRW-CV8062 | Annex Area 1 Reinforcement to Elevation 100'-00" |
| 583 | SV4-0000-CCW-CV8066 | UNIT 4 TRANSFORMER FOUNDATION CONCRETE & FORMWORK BASE SLAB PLACEMENT 2 |
| 584 | SV4-0000-CCW-CV8067 | Unit 4 Transformer Foundation Concrete & Formwork Base Slab Placement 3 |
| 585 | SV4-0000-CCW-CV8068 | Unit 4 Transformer Foundation Concrete & Formwork Base Slab Placement 4 |
| 586 | SV4-0000-CRW-CV8075 | UNIT 4 TRANSFORMER REPLACEMENT (PLACEMENT 3) |
| 587 | SV3-2050-SSW-CV1820 | CA81 TEMP FRAMING/PERMANENT FORMS (TB05) |
| 588 | SV3-SFS-THW-ME8080 | Hydro Testing of R219 SFS Piping |
| 589 | SV3-2060-CEW-CV7324 | 170' & 183' ELEV, SHEAR STUDS & EMBED REPAIRS |
| 590 | SV3-2060-CCW-CV4487 | UNIT 3 TURBINE BUILDING CA81 TABLE TOP GROUTING ELEVATION 170' |
| 591 | SV4-CDS-P0W-ME7117 | Installation of CDS Piping at Elevation 82'9" (Portion 2) |
| 592 | SV3-2038-SHW-EL6797 | Electrical Cable Tray supplemental Steel Installation in the Turbine Building, Elevation 100'-0", Area 8 from Colmns 14 to16 & H.05 to 1.2 |
| 593 | SV3-CA20-S8W-CV2267 | CA20 MODULE EXTERIOR WALL CONCRETE REINFORCEMENT |
| 594 | SV3-HDS-PHW-ME1372 | FABRICATION AND INSTALLATION OF HDS PIPING SUPPORTS |
| 595 | SV3-HDS-PHW-ME3751 | INSTALLATION AND FABRICATION OF HEATER DRAIN SYSTEM SUPPORTS |
| 596 | SV3-WWS-P0W-ME4633 | FABRICATION AND INSTALLATION OF WWS PIPING |
| 597 | SV3-CA20-S4W-CV1756 | INSTALLATION OF CA20 WALL 2 EMBED PLATES |
| 598 | SV3-CA20-S4W-CV2076 | EXTERIOR TEMPORARY ATTACHMENTS @ COLUMN LINE 4 |
| 599 | SV3-CA20-S8W-CV1690 | INSTALLATION OF CA20 MODULE COMMODITIES NI-3 AREA 5 AND 6 ROOM 12162 THRU 12169 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 600 | SV0-SAS-PLW-ME0710 | INSTALL AND FABRICATE SERVICE AIR SYSTEM (SAS) TO NUCLEAR ISLAND |
| 601 | SV3-CA20-S4W-CV2585 | CA20-SUB ASSEMBLY 4 WORK LIST ITEMS WB-W00152, WB-W00153, WB-W00154, WB-W00155, WB-W00156, WB-W00157, WB-W00158 & WB-W00159 |
| 602 | SV3-CA20-S4W-CV2586 | CA20 SUB ASSEMBLY 4 WORK LIST ITEMS WB-W00160, WB-W00161, WB-W00162, WB-W00163, WB-W00164, WB-W00165, WB-W00166, WB-W00167 |
| 603 | SV0-SES-ERW-EL7370 | INSTALL CONDUIT IN SES DUCT BANK/TRENCH FOR SECURITY LOCATED BETWEEN SITE GRID L1402-K1601 PHASE 10 |
| 604 | SV3-2032-SHW-EL6794 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE TURBINE BUILDING, ELEVATION 100'-0", AREA 2 FROM COLUMNS 17 TO 18 & P.1 TO R |
| 605 | SV3-1230-C0W-850001 | 100'-0" ELEV WALLS, CL 11 (WEST), WALL 69 |
| 606 | SV3-1230-C0W-850002 | 100'-0" ELEV WALLS, CL 11 (EAST), WALL 70 |
| 607 | SV3-1230-C0W-850003 | 100'-0" ELEV WALLS, CL I, WALL 71 |
| 608 | SV3-1230-C0W-850005 | 100'-0" ELEV WALLS, CL J, WALL 85 |
| 609 | SV3-1230-C0W-850006 | 100'-0" ELEV WALLS, CL K, WALL 83 |
| 610 | SV3-1230-C0W-850007 | 100'-0" ELEV WALLS, CL L, WALL 80 |
| 611 | SV3-1230-C0W-850008 | 100'-0" ELEV WALLS, CL M, WALL 79 |
| 612 | SV3-1230-C0W-850009 | 100'-0" ELEV WALLS, CL P, WALL 78 |
| 613 | SV3-1231-C0W-850001 | UNIT 3 AUXILIARY EL. 100 FT. AREA 1 - CIVIL - CONCRETE FOR TUBE STEEL |
| 614 | SV3-0150-ERW-EL7455 | CABLE TRAY SUPPORT FOR RAT4B |
| 615 | SV3-CA20-S4W-CV2108 | INTERIOR TEMPORARY ATTACHMENTS FOR SUB-ASSEMBLY 3 |
| 616 | SV4-MS09-MSW-ME7105 | INSTALLATION OF DTS EQUIPMENT ON THE 100' ELEVATION |
| 617 | SV4-ME3A-MEW-ME7423 | INSTALLATION OF CCS HEAT EXCHANGERS (CCS-ME-01A/B) |
| 618 | SV3-2034-SHW-EL6800 | Electrical Cable Tray Supplemental Steel Installation in the Turbine Building, Elevation 100'-0", Areas 0, 1 & 4 from Columns 12.1 to 14 & K.1 to R |
| 619 | SV3-2060-PHW-ME7887 | INSTALLATION OF STRUCTURAL STEEL FRAME FOR PIPE SUPPORTS IN HIGH PRESSURE TURBINE OPENING |
| 620 | SV4-WLS-P0W-ME6140 | INSTALLATION OF SMALL BORE CA01 WLS EMBEDDED PIPING (INCLUDE ISOMETRICS SV4-WLS-PLW-570, 57P, 57Q, 57R & 575) |
| 621 | SV4-2040-CCW-CV4615 | UNIT 4, TRUBINE BUILDING GROUTING ACTIVITIES ON 120' ELEVATION |
| 622 | SV3-CA01-MHW-CV2164 | LIFTING FRAMES AND BRACING SUBMODULES 13 THRU 16,32,33,39 & 36 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 623 | SV3-0150-ERW-EL7456 | CABLE TRAY SUPPORT RAT 4A |
| 624 | SV4-MS09-MSW-ME8109 | INSTALLATIN OF RO CARTRIDGE FILTER SKID (DTS-MS-01) RO UNIT AND FEED PUMP SKIDS (DTS-MS021/B), EDI UNITS (DTS-MS-041/B) AND PERMEATE PUMP & TOC REDUCTION SKIDS (DTS-MS-30A/B) |
| 625 | SV3-4032-SHW-EL8129 | Fabricate and Install Non-Seg Bus Duct Supports for SV3-ECS-EB1121, Annex Bldg. Area 2, Elev. 100'. |
| 626 | SV3-VWS-PLW-ME3017 | Installation of Small Bore VWS Piping (Including Isometric SV3-VWS-PLW-490) |
| 627 | SV3-1212-ERW-EL3159 | AUXILARY BUILDING UNIT 3, EL 66'-6", AREA 2, INSTALL DESIGN CONDUIT & CABLE TRAY. |
| 628 | SV3-PH01-CEW-CV7666 | Installation of Reactor Vessel Support Interior Anchor Bolt Assemblies |
| 629 | SV3-WWS-P0W-ME6704 | FABRICATION AND INSTALLATION OF WWS DRAIN HUBS ELEVATION 140' |
| 630 | SV3-4032-SHW-EL8130 | FABRICATE AND INSTALL NON-SEG BUS DUCT SUPPORTS FOR SV3-ECS-EB-1222, ANNEX BLDG. AREA 2, ELEV. 100'. |
| 631 | SV3-4032-SHW-EL8131 | Fabricate and Install Non-Seg Bus Duct Supports for SV3-ECS-EB1323, Annex Bldg. Area 2, Elev. 100'. |
| 632 | SV3-4032-SHW-EL8132 | Fabricate and Install Non-Seg Bus Duct Supports for SV3-ECS-EB1424, Annex Bldg. Area 2, Elev. 100'. |
| 633 | SV3-KB11-KBW-ME8392 | COMPLETION OF KB11 MODULE |
| 634 | SV3-CCS-THW-ME8079 | HYDRO TESTING OF R219 CCS PIPING |
| 635 | SV4-1020-CCW-CV5152 | UNIT 4 CONCRETE PLACEMENT 8A BELOW THE CONTAINMENT VESSEL FROM ELEV 82'-6" TO 87'6" |
| 636 | SV3-1231-CEW-850000 | FOREMAN'S BOOK: AUXILIARY NORTH EL 100' to 117'-6" CIVIL EMBEDMENTS |
| 637 | SV3-WLS-P0W-ME3720 | INSTALLATION OF SMALL BORE WLS PIPING (ISOMETRIC SV3-WLS-PLW-522) |
| 638 | SV3-WLS-P0W-ME3724 | INSTALLATION OF SMALL BORE WLS PIPING (ISOMETRIC SV3-WLS-PLW-532) |
| 639 | SV3-WLS-THW-ME6213 | HYDRO TEST THE UNIT 3 LIQUID RADWASTE SYSTEM PIPING IN FINAL PHASE NEAR MANHOLE |
| 640 | SV4-WLS-THW-ME6216 | HYDRO TEST THE UNIT 4 LIQUID RADWASTE SYSTEM PIPING FINAL PHASE |
| 641 | SV3-DOS-THW-ME8270 | PNEUMATIC TESTING OF THE UNIT 3 DIESEL FUEL OIL SYSTEM (DOS) PIPING |
| 642 | SV3-2070-SUW-CV0196 | Turbine Building Structural Steel Framing Sequence 15 |
| 643 | SV3-4052-CCW-CV7376 | U3 Annex Building Area 2 Concrete Form-work plan Elevation 117’6" to Elevation 135’3” |
| 644 | SV3-SFS-PHW-ME8756 | Fabrication/Installation of Pipe Supports for Isometric SV3-SFS-PLW-78B |
| 645 | SV3-SFS-PHW-ME8759 | Fabrication/Installation of Pipe Supports for Isometric Drawing SV3-SFS-PLW-785 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 646 | SV3-HDS-PHW-ME1368 | INSTALLATION AND FABRICATION OF HEATER DRAIN SYSTEM SUPPORTS |
| 647 | SV3-HDS-PHW-ME1364 | INSTALLATION AND FABRICATION OF HEATER DRAIN SYSTEM(HDS) PIPING SUPPORTS |
| 648 | SV4-HDS-PHW-ME5471 | INSTALLATION AND FABRICATION OF HEATER DRAIN SYSTEM(HDS) PIPING SUPPORTS |
| 649 | SV3-DWS-PHW-ME6244 | INSTALLATION OF SUPPORTS ON PIPE ISOMETRIC SV3-DWS-PLW-772 |
| 650 | SV3-ML05-MLW-ME5929 | INSTALLATION OF CA37 PENETRATIONS |
| 651 | SV4-WLS-P0W-ME8314 | ASME SECTION III - FABRICATION/INSTALLATION OF WLS PIPING LINES WLS-PL-L061 and WLS-PL-L110A on ISO SV4-WLS-PLW-750 |
| 652 | SV4-2050-CEW-CV8149 | 141'-3" ELEV, STUD WELDS, POUR #1 |
| 653 | SV3-2050-CCW-CV7037 | UNIT 3, TB GROUTING ACTIVITIES ON 141' ELEVATION |
| 654 | SV4-2040-EGW-EL8028 | ELECTRICAL GROUNDING INSTALLATION FOR THE TURBINE BUILDING AT ELEVATIONS 117'6" AND 120'-6" |
| 655 | SV3-CA20-ERW-EL5041 | INSTALL SCHEDULED FIELD ROUTED CONDUIT IN "RNS PUMP ROOM A" (12162) |
| 656 | SV3-WWS-PHW-ME6697 | INSTALLATION AND FABRICATION OF WASTE WATER SYSTEM PIPE SUPPORTS FOR 120' ELEVATION |
| 657 | SV4-ML05-MLW-ME8409 | INSTALL SV4 CA05 PENETRATION SV4-11209-ML-P01 |
| 658 | SV3-ML05-MLW-ME5903 | INSTALLATION OF CA32 PENETRATIONS |
| 659 | SV3-ML05-MLW-ME5963 | INSTALLATION OF CA58 PENETRATIONS 11400-ML-P10 & 11400-ML-P11 |
| 660 | SV4-WWS-PHW-ME5479 | INSTALLATION OF PIPE SUPPORTS FOR PIPING PACKAGE SV4-WWS-PHW-ME5466 |
| 661 | SV3-PXS-PHW-ME3787 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-02K |
| 662 | SV3-PXS-PHW-ME4500 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-01W |
| 663 | SV3-PXS-PHW-ME3361 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-01Q |
| 664 | SV3-PXS-PHW-ME3788 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-02L |
| 665 | SV4-ML05-MLW-ME8411 | INSTALL SV4 CA05 PENETRATION SV4-11209-ML-P03 |
| 666 | SV4-ML05-MLW-ME8412 | INSTALL SV4 CA05 PENETRATION SV4-11209-ML-P04 |
| 667 | SV3-PXS-MTW-ME2934 | INSTALLATION OF ACCUMULATOR TANK SV3-PXS-MT01A |
| 668 | SV4-CA20-ERW-EL6714 | INSTALL ELECTRICAL WALL PENETRATIONS IN U4 CA20 MODULE SUB-ASSEMBLY 1 |
| 669 | SV3-WLS-PHW-ME3872 | FABRICATION/INSTALLATION OF WLS PIPING SUPPORTS FOR ISOMETRICS: SV3-WLS-PLW-550, -551, -560, -56A |
| 670 | SV3-FPS-PHW-ME4309 | FABRICATION / INSTALLATION OF PIPE SUPPORTS FOR ISOMETRICS SV3-FPS-PLW-811, 812, & 831 |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 671 | SV3-WLS-PHW-ME8404 | FABRICATION/INSTALLATION OF WLS PIPE SUPPORTS FOR SV3-WLS-PLW-513 |
| 672 | SV3-WLS-PHW-ME8403 | FABRICATION/INSTALLATION OF WLS PIPE SUPPORTS FOR SV3-WLS-PLW-512 |
| 673 | SV3-WLS-PHW-ME8401 | FABRICATION/INSTALLATION OF WLS PIPE SUPPORTS FOR SV3-WLS-PLW-451 |
| 674 | SV3-WLS-PHW-ME8400 | FABRICATION/INSTALLATION OF WLS PIPE SUPPORTS FOR SV3-WLS-PLW-450 |
| 675 | SV4-HDS-PHW-ME5473 | INSTALLATION AND FABRICATION OF HEATER DRAIN SYSTEM(HDS) PIPING SUPPORT |
| 676 | SV3-CAS-PHW-ME6155 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWINGS (SV3-CAS-PLW-502) |
| 677 | SV3-ZAS-ERW-EL7501 | INSTALL CABLE TRAY SOUTHSIDE OF UNIT #3 TRANSFORMER AREA |
| 678 | SV4-WWS-PHW-ME5480 | INSTALLATION OF PIPE SUPPORTS FOR PIPING PACKAGE SV4-WWS-PHW-ME5467 |
| 679 | SV3-MSS-PHW-ME4660 | INSTALLATION OF PIPE SUPPORTS FOR PIPING PACKAGE SV4-MSS-P0W-ME4659 |
| 680 | SV3-MT6Z-MEW-ME5586 | INSTALLATION OF THE MAIN OIL TANK (MT-01) |
| 681 | SV3-CA04-S4W-CV1680 | CA04 TOP FLANGE FABRICATION AND ASSEMBLY |
| 682 | SV4-2020-SHW-EL8027 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE UNIT 4 TURBINE BUILDING AT ELEVATION 82'-9" |
| 683 | SV4-2050-CEW-CV8154 | UNIT 4, TURBINE BUILDING 141' ELEVATION STUD WELDS POUR #6 |
| 684 | SV4-HDS-PHW-ME5475 | INSTALLATION AND FABRICATION OF HEATER DRAIN SYSTEM(HDS) PIPE SUPPORT |
| 685 | SV4-FPS-PHW-ME5001 | FABRICATION/INSTALLATION OF FPS PIPE SUPPORTS (INCLUDING ISOMETRICS SV4-FPS-PLW-830, 825, 820) |
| 686 | SV3-4041-SAW-EL8771 | INSTALL SUPPLEMENTAL STEEL FOR ELECTRICAL HANGERS COL LN H9/H1.05 TO F9/F10.05 |
| 687 | SV3-2060-CRW-CV8370 | UNIT 3 TURBINE BUILDING 170' ELEVATED DECK REBAR FOR EQUIPMENT PADS & CURBS |
| 688 | SV3-2060-CRW-CV8368 | UNIT 3 TURBINE BUILDING 170' ELEVATED DECK REBAR FOR POUR #5 |
| 689 | SV3-PWS-P0W-ME4169 | INSTALLATION OF SMALL BORE PWS PIPING (INCLUDES ISOMETRIC SV3-PWS-PLW-912, 922, 940, 941, 94X) |
| 690 | SV3-PWS-P0W-ME4170 | INSTALLATION OF SMALL BORE PWS PIPING (INCLUDES ISOMETRIC SV3-PWS-PLW-954, 955, 956, 957) |
| 691 | SV4-WLS-P0W-ME8312 | ASME SECTION III - FABRICATION/INSTALLATION OF WLS PIPING LINES WLS-PL-L062 and WLS-PL-L110B on ISO SV4-WLS-PLW-731 |
| 692 | SV4-WLS-P0W-ME8313 | ASME SECTION III - FABRICATION/INSTALLATION OF WLS PIPING LINES WLS-PL-L063 and WLS-PL-L110C on ISO SV4-WLS-PLW-741 & SV4-WLS-PLW-74A |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 693 | SV3-PXS-PHW-ME4499 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-01R |
| 694 | SV3-CA03-S4W-CV2385 | SV3-CA03-GNR-000071 ¿ 3D SCAN OF ENTIRE CA03 MODULE |
| 695 | SV3-MT73-MTW-ME7068 | FABRICATION/INSTALLATION OF PXS GUTTER COLLECTION BOXES AND SUPPORTS |
| 696 | SV3-REFDOC-NI3-ME8892 | SV3 CONTAINMENT PIPING/MECHANICAL FOREMAN'S BOOK 1 |
| 697 | SV3-MSS-P0W-ME4655 | INSTALLATION OF MSS PIPING |
| 698 | SV4-VWS-PHW-ME7150 | INSTALLATION AND FABRICATION OF CENTRAL CHILLED WATER SYSTEM (VWS) PIPE SUPPORT |
| 699 | SV3-MSS-PHW-ME4658 | INSTALLATION OF PIPE SUPPORTS FOR PIPING PACKAGE SV3-MSS-P0W-ME4657 |
| 700 | SV4-FPS-PHW-ME5000 | FABRICATION/INSTALLATION OF FPS PIPE SUPPORTS (INCLUDING ISOMETRICS SV4-FPS-PLW-833) |
| 701 | SV3-2020-ERW-EL1840 | ELECTRICAL CABLE TRAY SUPPORTS INSTALLATION FOR THE TURBINE BUILDING AT ELEVATION 82'-9" |
| 702 | SV3-4030-EGW-EL1856 | PERFORM INSTALLATION OF UNDERGROUND COMMODITIES (EGS-GROUNDING) FOR THE ANNEX BLDG., AREA 1, ELEV. 100' & 107' - BETWEEN COLUMN LINES (9) TO (13) |
| 703 | SV3-WLS-PLW-ME0874 | Fabricate and Install WLS Piping Iso SV3-WLS-PLW-750-RESERVED FOR ORAN POE |
| 704 | SV3-WLS-P0W-ME3503 | INSTALLATION OF LARGE BORE WLS PIPING (INCLUDES: SV3-WLS-PLW-340, SV3-WLS-PLW-360, SV3-WLS-PLW-400, SV3-WLS-PLW-420) |
| 705 | SV3-WLS-P0W-ME3498 | INSTALLATION OF SMALL BORE WLS PIPING (ISOMETRICS SV3-WLS-PLW-221, -251) |
| 706 | SV3-CB00-S8W-CV4046 | U3 CONTAINMENT INSTALLATION OF CB MODULE 21 AT ELEV 83'-0" |
| 707 | SV0-ZRS-EWW-TP0879 | Installation of 13.8KV Temp Power Loop East of Unit 3 |
| 708 | SV0-PWS-PLW-ME1086 | Fabricate and install Potable Water Piping East & North of Building 307 |
| 709 | SV3-ME01-PLW-ME1163 | CONDENSER B-1ST EXTRACTON PIPING (EXTRACTION STEAM) |
| 710 | SV3-MS60-MEW-ME1645 | Installation of ASS Boiler Feedpumps (ASS-MP-04A & 04B) |
| 711 | SV3-WRS-PLW-ME0600 | WRS LARGE BORE PIPING INSTALLATION (INCLUDES ISOMETRIC SV3-WRS-PLW-57J) |
| 712 | SV3-2020-MEW-ME1399 | UNIT 3 CONDENSER C SPRING SUPPORT FOUNDATION INSTALLATION |
| 713 | SV3-ME01-PLW-ME1005 | UNIT 3 CONDENSER A: INSTALLATION OF UPPER SHELL NOZZLES |
| 714 | SV3-ML05-MLW-ME1570 | INSTALLATION OF EMBEDDED PIPING PENETRATIONS 82'-6" FLOORS ONLY |
| 715 | SV3-ME01-PLW-ME1159 | UNIT 3 CONDENSERS A: 1ST EXTRACTION PIPING (EXTRACTION STEAM) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 716 | SV3-ME2W-MEW-ME1360 | INSTALLATION OF HDS DRAIN COOLER CDS-ME-7C |
| 717 | SV3-2020-MEW-ME1398 | Unit 3 Condenser B Spring Support Foundation Installation |
| 718 | SV3-ME2W-MEW-ME1359 | INSTALLATION OF HDS DRAIN COOLER CDS-ME7B |
| 719 | SV3-WWS-PLW-ME1379 | UNIT 3 TURBINE BUILDING ELEVATION 100 FT. 0 IN. EMBEDDED WWS PIPING PACKAGE # 5 |
| 720 | SV3-2030-MEW-ME1695 | UNIT 3 CONDENSER A WATERBOX INSTALLATION |
| 721 | SV3-2030-MEW-ME1697 | UNIT 3 CONDENSER C WATERBOX INSTALLATION |
| 722 | SV3-WWS-P0W-ME2279 | ANNEX BUILDING - EMBEDDED WWS PIPING PACKAGE #1 |
| 723 | SV3-WLS-PHW-ME2320 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING WLS-PLW-380 |
| 724 | SV3-MS19-MEW-ME2497 | RESIN ADDITION HOPPER (CPS-MT-01) |
| 725 | SV3-KB11-KBW-ME0444 | INSTALLATION OF MODULE KB11 |
| 726 | SV3-CWS-PLW-ME2513 | INSTALLATION OF CWS PIPING FOR ISOMETRICS SV3-CWS-PLW-70AB, SV3-CWS-PLW-70AC, SV3-CWS-PLW-70AD, SV3-CWS-PLW-70AE |
| 727 | SV3-R106-R1W-ME0723 | R106 Mechanical Module |
| 728 | SV3-1000-Z0W-CV3911 | UNIT 3 SHIELD BUILDING REINFORCED CONCRETE REQUIREMENTS |
| 729 | SV3-1000-GCW-CV0675 | UNIT 3 NUCLEAR ISLAND CONSTRUCTION STAIRCASES |
| 730 | SV3-1110-CEW-CV1270 | UNIT 3 CONTAINMENT EMBEDDED PLATES AND ANCHOR BOLTS AT EL. 71FT-6IN |
| 731 | SV3-CB65-S4W-CV1723 | INSTALL AND REMOVAL OF LIFTING BEAM/LUG FOR CB65 |
| 732 | SV3-1200-Z0W-CV3909 | UNIT 3 AUXILIARY BUILDING REINFORCED CONCRETE REQUIREMENTS |
| 733 | SV3-4000-T2W-CV2232 | HSB ASSEMBLY & INSTALLER QUALIFICATION FOR ANNEX BUILDING AREA 4 |
| 734 | SV3-CA05-S4W-CV2054 | CA05 INSTALL REBAR FOR OVERLAY AND CONNECTION PLATES |
| 735 | SV3-ECS-CCW-CV1902 | Unit 3 ECS Ductbank |
| 736 | SV4-MT6A-MTW-ME8116 | Installation of Oil Storage Tanks (LOS-MT-02A/B) |
| 737 | SV3-1213-ERW-EL1624 | AUXILARY BUILDING UNIT 3, EL 66'-6", AREA 3, INSTALL DESIGNED ROUTED CABLE TRAYS AND CONDUIT" |
| 738 | SV0-ZRS-EWW-EL6159 | Electrical LOTO & Determination and Physical Removal of the North and/or South Louvers and Actuator Controls at 315 Bldg. for Diesel Generator Installation |
| 739 | SV3-ML05-MLW-ME4820 | ASME Section III - Installation of Penetration 11502-ML-P01 & 11502-ML-P02 (CA01) |
| 740 | SV3-WLS-P0W-ME4995 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES: SV3-WLS-PLW-512, SV3-WLS-PLW-513) |
| 741 | SV3-CAS-P0W-ME4393 | INSTALLATION OF SMALL BORE CAS PIPING (INCLUDES SV3-CAS-PLW-41C, 41F, 41G) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 742 | SV3-1110-CCW-CV1396 | CONCRETE INTERIOR CVBH UP TO ELEVATION 71'-6" |
| 743 | SV3-2000-SSW-CV1861 | UNIT 3 TURBINE FIELD REPAIRS AND MODIFICATIONS FOR GRATING AND HANDRAIL |
| 744 | SV4-MT2M-MTW-ME8124 | Installation of Chemical Addition Tank (VYS-MT-02) |
| 745 | SV3-WLS-P0W-ME3727 | Installation of Large Bore WLS Piping (Isometrics SV3-WLS-PLW-537,-538,-540) |
| 746 | SV3-WLS-P0W-ME3733 | Installation of Large Bore WLS Piping (Isometric SV3-WLS-PLW-630, 632, 690, 721) |
| 747 | SV3-WSS-P0W-ME3444 | INSTALLATION OF WSS PIPING (INCLUDES SV3-WSS-PLW-513, 514, 600, 601) |
| 748 | SV3-CAS-PHW-ME0728 | Fabrication/Installation of Pipe Supports for Isometric Drawings (SV3-CAS-PLW-327, 360) |
| 749 | SV3-CAS-PHW-ME0729 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWINGS (SV3-CAS-PLW-331) |
| 750 | SV3-CWS-XEW-CV0057 | Excavate and Backfill for CWS Piping U3 Phase 3 Supply Line <Works with SV3-CWS-PLW-ME0051> |
| 751 | SV3-WLS-P0W-ME3506 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES: SV3-WLS-PLW-510, SV3-WLS-PLW-511, SV3-WLS-PLW-514, SV3-WLS-PLW-515) |
| 752 | SV3-WLS-P0W-ME3507 | Installation of Large Bore WLS Piping (Includes: SV3-WLS-PLW-500) |
| 753 | SV3-WRS-P0W-ME3663 | Installation of Small Bore WRS Piping (Includes Isometrics SV3-WRS-PLW-824 , -829, -880) |
| 754 | SV3-WRS-P0W-ME3855 | Installation of Small Bore WRS Piping (Includes Isometric SV3-WRS-PLW-82H) |
| 755 | SV3-WRS-PLW-ME4454 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES SV3-WRS-PLW-839) |
| 756 | SV3-WRS-PLW-ME4459 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES SV3-WRS-PLW-842) |
| 757 | SV4-PY55-PYW-ME3244 | Assembly of the 120" x 108" CWS Reducers and CWS Expansion joint (Supply)" |
| 758 | SV4-PY55-PYW-ME3245 | Assembly of the 120" x 108" CWS Reducers and CWS Expansion joint (Return)" |
| 759 | SV3-ME3A-MEW-ME3693 | INSTALLATION OF TURBINE BLDG. CCS HEAT EXCHANGERS SV3-CCS-ME-01A AND 01B. |
| 760 | SV3-WLS-PLW-ME0901 | Fabricate and Install WLS Embedded Piping Iso SV3-WLS-PLW-576, 579 |
| 761 | SV3-KB23-KBW-ME1682 | Installation of Module KB23 (WLS Monitor Pump C) |
| 762 | SV3-2030-CCW-CV0219 | Miscellaneous Interior Walls and Curbs |
| 763 | SV3-1220-CCW-CV1889 | CONCRETE IN AUXILIARY BUILDING WALLS (19,20,20A,20B, AND 20C) UP TO ELEVATION 82'-6" |
| 764 | SV0-ZBS-CCW-CV2578 | ZBS Ductbank |
| 765 | SV0-DFS-CCW-CV2580 | DFS Ductbank |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 766 | SV3-CB00-S8W-CV3228 | INSTALLATION OF CB MODULES 22 7 23 AT ELEVATION 80'-6" |
| 767 | SV4-PGS-CCW-CV3427 | UNIT 4 JACK & BORE AND PGS ENCASEMENT CONSTRUCTION |
| 768 | SV3-1120-CCW-CV1818 | PLACEMENT, CURING, AND REPAIR OF CONCRETE INSIDE THE CV UP TO ELEV 83'-0" AND ELEV 84'-6" |
| 769 | SV3-WLS-THW-ME2213 | LIQUID RADWASTE SYSTEM (WLS) PIPING HYDROSTATIC TESTING |
| 770 | SV4-WRS-P0W-ME5328 | Fabrication/Installation of Small Bore WRS Leak Chase Piping Including SV4-WRS-PLW-86A, -86C, -808, -809, -868, -869 |
| 771 | SV3-CA03-GWS-ME8107 | WELDING PROCEDURES FOR CA03 |
| 772 | SV3-VWS-PLW-ME0500 | INSTALLATION OF SMALL BORE VWS PIPING (INCLUDES ISOMETRICS SV3-VWS-PLW-241, 323) |
| 773 | SV3-VWS-PLW-ME0501 | INSTALLATION OF SMALL BORE VWS PIPING (INCLUDES SV3-VWS-PLW-280, 353) |
| 774 | SV3-VWS-PLW-ME0502 | INSTALLATION OF SMALL BORE VWS PIPING (INCLUDES SV3-VWS-PLW-390, 424) |
| 775 | SV3-KB16-KBW-ME0443 | INSTALLATION OF MODULE KB16 |
| 776 | SV3-VWS-PLW-ME0503 | INSTALLATION OF SMALL BORE VWS PIPING (INCLUDES SV3-VWS-PLW-680,-453) |
| 777 | SV3-CAS-PLW-ME0461 | INSTALLATION OF KB15 CONNECTION PIPING |
| 778 | SV3-CAS-PLW-ME0458 | INSTALLATION OF SMALL BORE CAS PIPING (INCLUDES ISOMETRICS: SV4-CAS-PLW-423, 42C) |
| 779 | SV3-CAS-PHW-ME0727 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWINGS (SV3-CAS-PLW-323, 328) |
| 780 | SV3-FPS-PHW-ME0693 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWNGS SV3-FPS-PLW-810, 815 |
| 781 | SV4-2020-MEW-ME1481 | Unit 4 Condenser C Outlet Box Installation |
| 782 | SV3-DTS-PHW-ME1517 | Fabricate and Install Demineralized Water Treatment System (DTS) supports portion 3-(Raw Water Supply to DTS-MS-01) |
| 783 | SV3-ASS-PHW-ME1525 | FABRICATE/INSTALL OF AUXILIARY STEAM (ASS) SUPPORTS (PORTION 4) FOR ISOMETRIC# SV3-ASS-PLW-012, 010, 017, 02N, & 021 |
| 784 | SV3-WLS-PHW-ME0836 | FABRICATION/INSTALLATION OF SMALL BORE WLS PIPING SUPPORTS FOR ISOMETRICS SV3-WLS-PLW-35D, -35F, -35H, -35L |
| 785 | SV3-WLS-PHW-ME0829 | FABRICATION/INSTALLATION OF SMALL BORE WLS PIPE SUPPORTS FOR ISOMETRIC DRAWING WLS-PLW-720 |
| 786 | SV3-WLS-PLW-ME0531 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES ISOMETRICS SV3-WLS-PLW-35D, -35F, -35H, -35L) |
| 787 | SV3-WLS-PLW-ME0528 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES ISOMETRICS SV3-WLS-PLW-191, -255) |
| 788 | SV3-VWS-PHW-ME0701 | INSTALLATION OF LARGE BORE VWS PIPING SUPPORTS FOR ISOMETRIC DRAWINGS SV3-VWS-PLW-270, -484 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 789 | SV3-WLS-PHW-ME0840 | FABRICATION/INSTALLATION OF SMALL BORE WLS PIPING SUPPORTS (INCLUDES ISOMETRICS: SV3-WLS-PLW-33G, -33K) |
| 790 | SV3-WLS-PLW-ME0525 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES ISOMETRICS SV3-WLS-PLW-980, -981) |
| 791 | SV3-WLS-PHW-ME0828 | FABRICATION/INSTALLATION OF SMALL BORE WLS PIPE SUPPORTS FOR ISOMETRIC DRAWING WLS-PLW-66Z |
| 792 | SV3-WLS-PLW-ME0537 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES ISOMETRIC SV3-WLS-PLW-33E) |
| 793 | SV4-1220-SSW-CV4783 | UNIT 4 NUCLEAR ISLAND AUXILLIARY BUILDING AREAS 5 & 6 STRUCTURAL STEEL FOR ELEVATION 82'-6" |
| 794 | SV3-CA20-S5W-CV1903 | CA20 N&D REWORK TO BE PERFORMED |
| 795 | SV3-CA20-S8W-CV1905 | INSTALLATION OF CA20 MODULE CIVIL COMMODITIES AND REINFORCEMENT NI3 AREA 5 & 6 ELEVATION 92'-6" |
| 796 | SV3-PH01-CEW-CV7665 | INSTALLATION OF REACTOR VESSEL SUPPORT MAIN EMBEDMENT ASSEMBLY |
| 797 | SV3-CA20-S5W-CV2597 | ADDITION OF FLOOR REBAR SUBMODULES 30, 71, 72, 73 |
| 798 | SV3-CA20-S4W-CV0439 | CA20 SA4 EL 98'-1" Floor Installation (CA20-51) |
| 799 | SV3-4041-ERW-EL7563 | INSTALLATION OF CONDUIT SLEEVES FOR RACEWAY PENETRATIONS, ANNEX BUILDING, AREA 1, ELEVATION 117'-6" |
| 800 | SV4-WWS-PHW-ME7547 | INSTALLATION OF ANNEX BLDG WWS PIPE SUPPORTS (ISOMETRIC SV4-WWS-PLW-951, 953) |
| 801 | SV3-WSS-P0W-ME3443 | INSTALLATION OF SMALL BORE PIPING (SV3-WSS-PLW-122, 400, 510, 511, 512) |
| 802 | SV3-CA01-S4W-CV2151 | INSTALL CA01-07 PERMANENT WELDED ATTACHMENTS |
| 803 | SV3-CA01-S4W-CV2149 | INSTALL CA01-05 PERMANENT WELDED ATTACHMENTS |
| 804 | SV3-CA01-S4W-CV2150 | INSTALL CA01-06 PERMANENT WELDED ATTACHMENTS |
| 805 | SV3-1210-ERW-EL3163 | AUXILARY BUILDING UNIT 3, EL 66'-6", AREA 1, INSTALL TYPICAL RACEWAY SUPPORTS. |
| 806 | SV3-2020-EGW-EL1616 | ELECTRICAL GROUNDING TERMINATIONS FOR THE TURBINE BUILDING AT ELEVATION 82'-9" |
| 807 | SV4-4032-CCW-CV8061 | UNIT 4 ANNEX AREA 2 EAST SUMP AND ELEVATOR PIT INSTALLATION |
| 808 | SV4-0000-CCW-CV8065 | Unit 4 Transformer Foundation Concrete & Formwork Base Slab Placement 1 |
| 809 | SV4-WLS-PHW-ME3290 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING WLS-PLW-362 |
| 810 | SV3-WWS-P0W-ME3446 | INSTALLATION OF LARGE BORE WWS PIPING (INCLUDES SV3-WWS-PLW-32A, 32B, 32D, 32L, 334) |
| 811 | SV3-WRS-P0W-ME3794 | INSTALLATION OF LARGE BORE WRS PIPING (INCLUDES SV3-WRS-PLW-568, 569, 594) |
| 812 | SV3-WLS-PHW-ME0769 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING WLS-PLW-201 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 813 | SV3-4033-CEW-CV2838 | U3 ANNEX AREA 3 EMBEDDED ITEMS AND ANCHOR BOLTS FROM ELEVATION 100'-0" TO 107'-2" |
| 814 | SV3-WRS-P0W-ME3657 | INSTALLATION OF LARGE BORE WRS PIPING (INCLUDES ISOMETRICS SV3-WRS-PLW-56C) |
| 815 | SV4-2131-ERW-EL7377 | ELECTRICAL CONDUIT SLEEVE INSTALLATION FOR THE UNIT 4 TURBINE BUILDING 1ST BAY WALLS AT THE 100' |
| 816 | SV4-CA05-S5W-CV6037 | CA05-05 UNSATISFACTORY IRs AND N&D REPAIRS, E&DCRs AND LOOS PARTS - STRUCTURAL |
| 817 | SV3-CA20-S5W-CV2598 | ADDITION OF FLOOR REBAR SUB-MODULES 26,27,28,29 |
| 818 | SV3-CA01-S5W-CV6083 | INSTALLATION OF LANDING PLATES ON CA01 |
| 819 | SV3-DOS-CCW-CV8391 | UNIT 3 DOS TANK B WALL PLACEMENTS 2&3 |
| 820 | SV3-MS45-MEW-ME1893 | INSTALL FEEDWATER MAIN AND BOOSTER PUMP PACKAGE FOR MS-01C |
| 821 | SV4-SS01-Z0W-CV4382 | UNIT 4 STRUCTURAL STEEL SAFETY CLASS C REQUIREMENTS |
| 822 | SV3-VAS-SHW-ME4779 | FABRICATION AND INSTALLATION OF VAS DUCT SUPPORTS IN ROOM 12153 |
| 823 | SV3-2030-EGW-EL1751 | ELECTRICAL GROUNDING TERMINATIONS FOR THE TURBINE BUILDING AT ELEVATION 100'-0" |
| 824 | SV3-4032-ERW-EL1858 | PERFORM INSTALLATION OF UNDERGROUND COMMODITIES (EMBEDDED CONDUIT) FOR THE ANNEX BLDG., AREA 2, ELEV. 100' & 107' |
| 825 | SV3-CAS-PHW-ME0790 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWINGS SV3-CAS-PLW-501, 504 |
| 826 | SV3-WLS-PHW-ME0819 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING WLS-PLW-140 |
| 827 | SV3-WLS-P0W-ME3449 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES ISOMETRICS SV3-WLS-PLW-031,032) |
| 828 | SV4-0500-CFW-CV2664 | INSTALL/REMOVE 2" SHAKE SPACE FORMS |
| 829 | SV3-CCS-PHW-ME0802 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-CCS-PLW-530, 550 |
| 830 | SV3-WLS-PHW-ME0830 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWINGS WLS-PLW-93A, -936, -990 |
| 831 | SV3-1230-CCW-CV2440 | AUX BUILDING EXTERIOR WALLS (43, 44, 45, 46 & 47) UP TO EL 100'-0" |
| 832 | SV3-CA04-S4W-ME1732 | CA04 POWER RANGE DETECTOR WELLS INSTALLATION |
| 833 | SV3-CA04-S4W-ME1733 | CA04 INTERMEDIATE RANGE DETECTOR WELLS INSTALLATION |
| 834 | SV3-SWS-PHW-ME1384 | INSTALLATION OF SWS LARGE BORE PIPING SUPPORTS FOR PIPING INCLUDED IN THE SV3-SWS-PLW-ME1356 WORK PACKAGE. |
| 835 | SV3-CAS-PLW-ME0456 | INSTALLATION OF SMALL BORE CAS PIPING (INCLUDES ISOMETRICS: SV3-CAS-PLW-331) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 836 | SV3-4041-CCW-CV3182 | U3 ANNEX BUILDING AREA 1 CONCRETE & FORMWORK FROM EL. 100'-0" TO EL. 117'-6" |
| 837 | SV3-ML05-MLW-ME5905 | INSTALLATION OF CA35 PENETRATIONS |
| 838 | SV3-4031-ERW-EL1859 | PERFORM INSTALLATION OF UNDERGROUND COMMODITIES (EMBEDDED CONDUIT) FOR THE ANNEX BLDG., AREA 1, ELEV. 100'-BETWEEN COLUMN LINES (9) TO (13) |
| 839 | SV3-4033-ERW-EL1857 | PERFORM INSTALLATION OF UNDERGROUND COMMODITIES (EMBEDDED CONDUIT) FOR THE ANNEX BLDG., AREA 3, 100' & 107' - BETWEEN COLUMN LINES (2) to (4.1). |
| 840 | SV3-DOS-CCW-CV6811 | Diesel Generator Fuel oil storage foundation |
| 841 | SV3-CDS-CCW-CV6812 | CONDENSATE TANK FOUNDATION |
| 842 | SV3-CVS-PLW-ME0929 | Fabricate and Install Small Bore CVS Piping Iso SV3-CVS-PLW-07J |
| 843 | SV0-YFS-PLW-ME1087 | FABRICATE AND INSTALL THE YARD FIRE WATER LINE FROM BUILDING 301 TO BUILDING 304. |
| 844 | SV3-CES-PLW-ME1653 | Fabricate and Install Condenser Tube Cleaning System (CES) Piping In Turbine Building Elev. 82'-6" - 100'-0" (ISO SV3-CES-PLW-700,711,720,730,731,732,733,734,735,736,780) |
| 845 | SV0-RWS-P0W-ME5966 | FABRICATE AND INSTALL RAW WATER SYSTEM (RWS) TEMPORARY FLUSH LINE FOR START UP, |
| 846 | SV3-2030-CCW-CV0184 | 100' EL. Concrete Foundation Excluding 1st Bay |
| 847 | SV3-4001-SSW-CV3905 | Annex Building Area 1 Metal Decking and Grating Installation |
| 848 | SV3-CR10-CRW-CV0322 | INSTALLATION OF LAYER 4-10 REINFORCING FOR THE CR10 MODULE |
| 849 | SV3-CR10-CRW-CV0323 | THE ERECTION OF THE STRUCTURAL STEEL FOR THE CR10 MODULE ON PAD 139. |
| 850 | SV3-WLS-CCW-CV1845 | GROUT PLACEMENT UNDER MISCELLANEOUS EQUIPMENT AND TANKS IN THE UNIT 3 NUCLEAR ISLAND AUXILIARY BUILDING AT ELEVATION 66'-6" |
| 851 | SV3-ASS-PLW-ME1424 | FABRICATE AND INSTALL AUXILIARY STEAM SYSTEM(ASS) PIPING PORTION 1 FOR 82-9 |
| 852 | SV3-KB12-KBW-ME0450 | INSTALLATION OF MODULE KB12 |
| 853 | SV3-ME01-PLW-ME0991 | Unit 3 Condenser A, B & C: Hotwell Piping |
| 854 | SV3-1200-CRW-CV1411 | UNIT 3 AUXILIARY BUILDING EL 66-6 TO 82-6 REBAR FOR WALLS 19 AND 20 |
| 855 | SV3-2030-CCW-CV0226 | U3 Turbine Grouting Activities Elevation 100’-0" |
| 856 | SV3-CA05-CRW-CV3668 | CA05 WELDABLE COUPLER REINFORCEMENT |
| 857 | SV3-SWS-PHW-ME1506 | INSTALLATION OF SWS LARGE BORE PIPING SUPPORTS FOR PIPING INCLUDED IN THE SV3-SWS-PLW-ME1497 WORK PACKAGE. PART I |
| 858 | SV3-VAS-MDW-ME3387 | R161 MODULE HVAC COMPLETION |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 859 | SV3-FPS-P0W-ME1753 | INSTALL FIRE PROTECTION PIPING AND HYDRANTS WAST OF UNIT 3 ANNEX |
| 860 | SV3-FPS-P0W-ME1754 | FABRICATE AND INSTALL FIRE PROTECTION PIPING FROM UNIT 3 ANNEX TO UNIT 3 DIESEL GENERATOR BLDG |
| 861 | SV3-SWS-PHW-ME1425 | INSTALLATION OF SWS LARGE BORE PIPING SUPPORTS FOR PIPING INCLUDED IN THE SV3-SWS-PLW-ME1357 WORK PACKAGE. PART II |
| 862 | SV3-SWS-PHW-ME1385 | INSTALLATION OF SWS LARGE BORE PIPING SUPPORTS FOR PIPING INCLUDED IN THE SV3-SWS-PLW-ME1357 WORK PACKAGE. PART I |
| 863 | SV3-ME01-PLW-ME1170 | Condenser C-4th Extraction Piping (Extraction Steam) |
| 864 | SV3-ME01-PLW-ME1169 | Condenser C-3rd Extraction Piping (Extraction Steam) |
| 865 | SV3-ME01-PLW-ME1013 | Unit 3 Condenser A: Installation of Water Curtain Spray Piping |
| 866 | SV3-CA04-S4W-ME1731 | CA04 SOURCE RANGE DETECTOR WELLS INSTALLATION |
| 867 | SV3-MP04-MEW-ME3569 | INSTALLATION OF SWS SERVICE WATER PUMP A (SWS-MP-01A/B) |
| 868 | SV3-SDS-P0W-ME2301 | FABRICATE AND INSTALL SANITARY DRAIN PIPING UNDER THE UNIT 3 ANNEX SLAB #3 |
| 869 | SV3-CAS-PLW-ME1661 | Fabricate and Install Compressed & Instrument Air Piping & Components from Unit 3 Annex Building to Unit 3 Diesel Generator Building |
| 870 | SV3-WWS-CCW-CV2579 | UNIT 3 WWS Ductbank |
| 871 | SV3-2101-CFW-CV7034 | UNIT 3 TURBINE FIRST BAY WALLS FORMWORK |
| 872 | SV4-CB65-S5W-CV2570 | CB65 OVERLAY PLATE (OLP) INSTALLATION |
| 873 | SV3-ME01-PLW-ME1162 | Condenser A-4th Extraction Piping (Extraction Steam) |
| 874 | SV3-1230-CCW-CV2444 | AUX BUILDING MISCELLANEOUS WALLS (38, 39, 40, 41 & 48) UP TO EL 100'-0" |
| 875 | SV3-CA01-S4W-CV2089 | CA01-41 SUBMODULE INSTALLATION |
| 876 | SV3-CA01-S5W-CV5892 | CA01-45 Submodule Erection |
| 877 | SV3-1220-CCW-CV1611 | INSTALLATION OF REBAR, EMBED PLATES, CONCRETE, AND FORMWORK FOR U3 AUX. BLDG. CONCRETE BEAMS-EL.82'-6" |
| 878 | SV3-SWS-PLW-ME1495 | INSTALLATION OF SWS LARGE BORE PIPING (INCLUDES ISOMETRICS SV3-SWS-PLW-070, 071, 072, 078, 07A, 07B) |
| 879 | SV3-ML05-MLW-ME5064 | INSTALLATION OF CA01 PENETRATIONS |
| 880 | SV3-ME01-PLW-ME1166 | Unit 3 Condenser B: 4th Extraction Piping (Extraction Steam) |
| 881 | SV3-ME01-PLW-ME1161 | Condenser A-3rd Extraction Piping (Extraction Steam) |
| 882 | SV3-ME01-PLW-ME1112 | Hotwell Interconnection Piping Package #1 |
| 883 | SV3-ME01-PLW-ME1113 | Hotwell Interconnection Piping Package #2 |
| 884 | SV3-2020-MEW-ME1490 | Unit 3 Condenser C Installation (Lower & Upper Shell) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 885 | SV3-ME01-PHW-ME1450 | Unit 3 Condenser B: Fabrication & Installation of Casing Drain Piping Supports |
| 886 | SV3-ME01-PLW-ME0915 | Condenser A: Vacuum Piping |
| 887 | SV3-ME01-PLW-ME1022 | Condenser C: Vacuum Piping |
| 888 | SV3-FPS-P0W-ME2268 | FABRICATE AND INSTALL PHASE 2 FIRE PROTECTION LINE NORTH OF UNIT 3 annex to transformer yard. |
| 889 | SV3-ME01-PLW-ME0985 | Condenser B: Vacuum Piping |
| 890 | SV3-ME01-PLW-ME1165 | Condenser B-3rd Extraction Piping (Extraction Steam) |
| 891 | SV3-2030-MEW-ME1696 | UNIT 3 CONDENSER B WATERBOX INSTALLATION |
| 892 | SV3-0000-CRW-CV2375 | UNIT 3 TRANSFORMER FOUNDATION REBAR |
| 893 | SV3-0000-CCW-CV2126 | UNIT 3 TRANSFORMER FOUNDATION CONCRETE AND FORMWORK |
| 894 | SV3-WWS-P0W-ME3652 | INSTALLATION OF TURBINE BUILDING WWS PIPING FOR ISOMETRICS SV3-WWS-PLW-06B, 06BF, 06D, 06E, 06F, 06G, 06L, 06J, 06K, 06P |
| 895 | SV3-FPS-THW-ME7069 | FPS HYDROSTATIC TESTING |
| 896 | SV4-CA20-S4W-CV5288 | CA20-10 MAP OUT TEMPORARY ATTACHMENTS |
| 897 | SV3-MS21-MEW-ME4604 | INSTALLATION OF COOLING WATER MIXING SKID (SSS-MS-04) |
| 898 | SV3-4034-CCW-CV2620 | ANNEX AREA 4 FOUNDATION FORMWORK AND CONCRETE |
| 899 | SV3-CA01-S5W-CV5890 | SUBASSEMBLY 1: TOP CAP FABRICATION |
| 900 | SV3-CA01-S5W-CV5891 | SUBMODULE 1 TOP CAP INSTALLATION |
| 901 | SV3-FPS-THW-ME7213 | Hydro test the Unit 3 Fire Protection System (FPS) Piping on Isometrics (SV3-FPS-PLW-958,959,95AQ,95AR,95AS,95AT) |
| 902 | SV3-4042-CCW-CV3179 | Annex Area 2 Formwork and Concrete to Elevation 117’-6’’ |
| 903 | SV3-FPS-P0W-ME4186 | INSTALLATION OF LARGE BORE FPS PIPING (INCLUDES ISOMETRICS SV3-FPS-PLW-821, -827, -829, -82A) |
| 904 | SV3-CA01-S4W-CV4076 | CA01-11 OVERLAY PLATES AND PERMANENT WELDED |
| 905 | SV3-1210-ERW-EL1623 | Install Design Routed Raceway and Supports for Area 1 & 2 El. 66'-6" |
| 906 | SV3-CA20-S4W-CV0432 | CA20 SA2 EL 135'-3" FLOOR INSTALLATION (CA20-58) |
| 907 | SV3-CA20-S4W-CV0431 | Installation of CA20 SA2 EL 117'-6" Floor Submodules (Submods 56, 57, 76)RESERVED FOR RUSSELL FINDLEY |
| 908 | SV3-CA20-S4W-CV0426 | CA20 SA1 EL 117'-6" & 135'-3" FLOOR INSTALLATION (CA20-59,60,61,62,63,77) |
| 909 | SV3-CA20-S8W-CV2537 | CA20 MODULE FLOOR CIVIL COMMODITIES FROM EL. 100'-0" TO EL. 135'-3" |
| 910 | SV3-VAS-MXW-CT7420 | U3 AUX BLDG. VAS SUPPORTS REWORK |
| 911 | SV3-CA20-S4W-CV0430 | CA20 SA2 EL 107'-2" Floor Installation (CA20-75) |

# Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 912 | SV3-CA20-S4W-CV2208 | CA20-SUB ASSEMBLY 2 MISC. REWORK TO CLOSE N&Ds |
| 913 | SV3-CA20-S4W-CV2209 | CA20 MISCELLANEOUS N&Ds AND WORK LIST ITEMS CLOSURE |
| 914 | SV3-WLS-PHW-ME3526 | FABRICATION/INSTALLATION OF SMALL BORE WLS PIPING SUPPORTS FOR ISOMETRIC: SV3-WLS-PLW-050 |
| 915 | SV3-WLS-PHW-ME0770 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING WLS-PLW-215 |
| 916 | SV3-WLS-PHW-ME0771 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWINGS WLS-PLW-33A, -260 |
| 917 | SV3-WLS-PHW-ME0772 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING WLS-PLW-362 |
| 918 | SV3-WRS-P0W-ME3797 | INSTALLATION OF LARGE BORE WRS PIPING (INCLUDES SV3-WRS-PLW-668, 669) |
| 919 | SV3-CVS-PLW-ME0498 | INSTALLATION OF SMALL BORE CVS PIPING (INCLUDES SV3-CVS-PLW-506) |
| 920 | SV3-CCS-PHW-ME0803 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-CCS-PLW-609 |
| 921 | SV3-WLS-PHW-ME0832 | FABRICATION/INSTALLATION OF SMALL BORE WLS PIPING SUPPORTS FOR ISOMETRIC SV3-WLS-PLW-961 |
| 922 | SV3-CCS-PHW-ME0799 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-CCS-PLW-302 |
| 923 | SV3-PXS-P0W-ME3699 | FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-299 (CA03 PIPING) |
| 924 | SV3-MP50-MPM-ME1725 | INSTALLATION OF TURBINE BLDG. SUMP PUMPS SV3-WWS-MP-01A/01B, SV3-WWS-MP-07A/07B AND SV3-WWS-MP-08A/08B. |
| 925 | SV3-MS60-MEW-ME3571 | INSTALLATION OF ASS ELECTROLYTE FEED TANK (ASS-MT-06) |
| 926 | SV3-WRS-P0W-ME3792 | INSTALLATION OF LARGE BORE WRS PIPING (INCLUDES SV3-WRS-PLW-52C, 52E, 52G, 534) |
| 927 | SV3-CVS-P0W-ME3901 | INSTALLATION OF LARGE BORE CVS PIPING (INCLUDES SV3-CVS-PLW-524, 533, 560) |
| 928 | SV4-WRS-P0W-ME5419 | WRS EMBEDDED PIPING INSTALLATION (INCLUDING ISOMETRIC SV4-WRS-PLW-522) |
| 929 | SV3-2050-MEW-ME2273 | INSTALL CONDENSER C CONNECTION PIECE |
| 930 | SV3-2050-MEW-ME2271 | INSTALL CONDENSER A CONNECTION PIECE |
| 931 | SV3-2050-MEW-ME2272 | INSTALL CONDENSER B CONNECTION PIECE |
| 932 | SV4-AX01-AXW-CT7542 | UNIT 4 CONTAINMENT COATING REQUIREMENTS, |
| 933 | SV3-DOS-THW-ME2641 | (BLANK) |
| 934 | SV3-CA01-S4W-CV2250 | INSTALL CA01-46 PERMANENT WELDED ATTACHMENTS |
| 935 | SV3-WRS-P0W-ME2491 | FABRICATION AND INSTALLATION OF LARGE BORE WRS PIPING (ISOMETRIC SV3-WRS-PLW-652) |
| 936 | SV3-CA01-S4W-CV3383 | CA01-22 OVERLAY PLATES AND ATTACHMENTS |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 937 | SV4-2030-MEW-ME7698 | UNIT 4 CONDENSER C WATERBOX INSTALLATION |
| 938 | SV3-CA01-S5W-CV4216 | CA01 MISCELLANEOUS UNSATISFACTORY IRS, N&Ds, AND E&DCRs REWORK/REPAIRS |
| 939 | SV3-WLS-P0W-ME6168 | UNIT 3 FINAL PHASE WLD DOUBLE WALL PIPING INSTALLATION NEAR THE WLS/WWS TIE-IN MANHOLE |
| 940 | SV3-MS45-MEW-ME1892 | INSTALL FEEDWATER MAIN AND BOOSTER PUMP PACKAGE FOR MS01-B |
| 941 | SV3-MS45-MEW-ME1891 | INSTALL FEEDWATER MAIN AND BOOSTER PUMP PACKAGE FOR MS-01A |
| 942 | SV3-DOS-CCW-CV8106 | UNIT 3 DIESEL GENERATOR FUEL OIL STORAGE WALLS |
| 943 | SV3-DTS-P0W-ME3581 | INSTALLATION OF DTS PIPING FOR ISOMETRICS SV3-DTS-PLW-01AN AND SV3-DTS-PLW-01AP |
| 944 | SV4-1220-SSW-CV4780 | Unit 4 Nuclear Island Auxiliary Building Area 1 Structural Steel for Elevation 82'-6" |
| 945 | SV3-WWS-MYW-ME7859 | INSTALL VALVE BOXES FOR UNIT 3 WWS PIPING IN DIESEL FUEL OIL TANK AREA. |
| 946 | SV4-2000-SXW-CT7845 | U4 TURBINE BUILDING STRUCTURAL STEEL REWORK |
| 947 | SV3-WWS-CCW-CV3367 | WASTE WATER RETENTION |
| 948 | SV4-1220-EGW-EL4809 | U4-AUXILIARY BUILDING INSTALL ELECTRICAL PENETRATIONS AND GROUNDING FOR WALLS EL82'6' TO 100'0", AREAS 1&2 |
| 949 | SV3-ML10-MLW-ME8733 | PLACEMENT OF CONTAINMENT PENETRATIONS P05, P27, & P28 |
| 950 | SV3-DWS-PHW-ME7047 | INSTALLATION OF ANNEX BLDG DWS PIPE SUPPORTS (ISOMETRICS SV3-DWS-PLW-142, -242, -256). |
| 951 | SV3-DWS-P0W-ME6672 | INSTALLATION OF ANNEX BLDG DWS PIPING (ISOMETRICS SV3-DWS-PLW-243, -244 |
| 952 | SV4-CAS-P0W-ME2592 | FABRICATE AND INSTALL CAS SMALL BORE PIPING SHOWN ON ISOMETRIC DRAWING# SV4-CAS-PLW-785 AND 786 |
| 953 | SV3-CAS-P0W-ME2590 | FABRICATE AND INSTALL CAS SMALL BORE PIPING SHOWN ON ISOMETRIC DRAWING# SV3-CAS-PLW-681 AND 682 |
| 954 | SV3-PXS-PHW-ME7052 | Installation of Piping Supports for Isometric SV3-PXS-PLW-66N |
| 955 | SV4-1220-SSW-CV4781 | UNIT 4 NUCLEAR ISLAND AUXILIARY BUILDING AREA 2 STRUCTURAL STEEL FOR ELEVATION 82'-6" |
| 956 | SV3-2101-CEW-CV7035 | Unit 3, Turbine Building, 1st Bay Walls from 122' to 140', Terminators |
| 957 | SV3-WRS-PLW-ME4434 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES SV3-WRS-PLW-810) |
| 958 | SV4-2030-MEW-ME7696 | UNIT 4 CONDENSER A WATERBOX INSTALLATION |
| 959 | SV3-0000-ELW-EL7397 | INSTALLATION OF CONDUIT FOR UNIT 3 STANDARD PLANT YARD TRANSFORMER AREA LIGHTING |
| 960 | SV3-WLS-P0W-ME3505 | INSTALLATION OF LARGE BORE WLS PIPING (INCLUDES: SV3-WLS-PLW-450, SV3-WLS-PLW-451, SV3-WLS-PLW-452, SV3-WLS-PLW-453) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 961 | SV3-CA20-CCW-CV5445 | UNIT 3 CA20 WALLS CONCRETE PLACEMENT FROM ELEV. 66'-6" TO 128'-1" |
| 962 | SV4-2030-MEW-ME7697 | UNIT 4 CONDENSER B WATERBOX INSTALLATION |
| 963 | SV3-CA01-S4W-CV4083 | CA01-19 OLP, SAND PERMANENT WELDED ATTACHMENTS |
| 964 | SV3-CA01-S4W-CV2247 | INSTALL CA01-30 PERMANENT WELDED ATTACHMENTS AND OVERLAY PLATES (OLP) |
| 965 | SV3-WLS-PLW-ME0520 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES: SV3-WLS-PLW-591) |
| 966 | SV3-WLS-PLW-ME0526 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES ISOMETRICS SV3-WLS-PLW-961) |
| 967 | SV3-WRS-PLW-ME0485 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES ISOMETRIC SV3-WRS-PLW-82J) |
| 968 | SV3-4033-CCW-CV2837 | UNIT 3 ANNEX BUILDING AREA 3 FORMWORK AND CONCRETE FROM EL. 100'-0" TP 107'-2" |
| 969 | SV3-WLS-PLW-ME0514 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES ISOMETRICS SV3-WLS-PLW-190) |
| 970 | SV3-WGS-P0W-ME3436 | INSTALLATION OF SMALL BORE WGS PIPING (INCLUDES SV3-WGS-PLW-420, -422, -547) |
| 971 | SV3-WLS-PHW-ME0822 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWINGS WLS-PLW-265, -275 |
| 972 | SV3-WRS-P0W-ME3667 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDING ISOMETRICS SV3-WRS-PLW-85A, -85B, -850, -851, -852, -853, -854, -855, -856, -857, -858, -859) |
| 973 | SV3-MT2Y-MEW-ME3695 | INSTALLATION OF HDS LOW PRESSURE DRAIN TANKS (HDS-MT-04A/B/C) |
| 974 | SV3-VYS-P0W-ME8643 | INSTALLATION OF ANNEX BLDG VYS PIPING (ISOMETRIC SV3-VYS-PLW-423, -424, -425, -426, -428) |
| 975 | SV4-SDS-P0W-ME7549 | Installation of Annex Bldg SDS Embedded Piping (Isometric SV4-SDS-PLW-401, 402, 403, 404, 405) |
| 976 | SV3-2101-CCW-CV7317 | UNIT 3, TURBINE BUILDING, FIRST BAY WALL CONCRETE UP TO 122', POUR 1E |
| 977 | SV3-2101-CCW-CV7314 | UNIT 3, TURBINE BUILDING, FIRST BAY WALL CONCRETE UP TO 122', POUR 1W |
| 978 | SV3-ECS-ERW-EL1796 | Installation of Underground Commodities (Manholes and Duct Banks for the ECS) Main AC Power System from the Diesel Generator Bldg. to the Annex Bldg. - Phase 1 |
| 979 | SV3-PXS-P0W-ME3240 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC # SV3-PXS-PLW-029 (LINE NUMBERS PXS-PL-L112B) |
| 980 | SV4-ZBS-ERW-EL2642 | Install ZBS Ductbank - North Of Unit 4 Turbine Bldg. - Phase 7 |
| 981 | SV3-CB00-S8W-CV3229 | INSTALLATION OF CB MODULES 24 & 25 AT ELEVATION 89'-6" & 87'-6" |
| 982 | SV3-1230-CCW-CV2441 | AUX BUILDING EXTERIOR WALLS (25A, 26, 27, 28 & 42) UP TO EL 100'-0" |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 983 | SV3-1130-CRW-CV4054 | U3 CONTAINMENT CONCRETE REINFORCEMENT EL 84FT-6IN TO EL 87FT-6IN |
| 984 | SV3-1220-CRW-CV1586 | UNIT 3 AUXILIARY BUILDING PERIMETER A3 (82'-6") WALLS REBAR INSTALLATION |
| 985 | SV3-CA01-S5W-CV4288 | CA01 MISC. WORK, MISC. UNSAT. IRS/ N&DS AND E&DCRS |
| 986 | SV3-CA01-S4W-CV2248 | INSTALL CA01-31 PERMANENT WELDED ATTACHMENTS |
| 987 | SV3-CA01-S4W-CV4088 | INSTALL CA01-36 PERMANENT WELDED ATTACHMENTS |
| 988 | SV3-CA01-S4W-CV2249 | Install CA01-34 Permanent Welded Attachments |
| 989 | SV3-CA01-S4W-CV4089 | INSTALL CA01-39 PERMANENT WELDED ATTACHMENTS |
| 990 | SV3-1020-CCW-CV2699 | CONCRETE IN AREA BELOW CONTAINMENT VESSEL FROM EL 82'-6" TO EL 98'-0" |
| 991 | SV3-CA01-CRW-CV6220 | INSTALLATION OF REINFORCING STEEL INTO CA01 MODULE WELDABLE COUPLERS |
| 992 | SV3-1100-Z0W-CV3928 | UNIT 3 CONTAINMENT REINFORCED CONCRETE REQUIREMENTS |
| 993 | SV3-1020-CEW-CV2581 | Installation of Embed Plates For Shield Wall And Lower Annulus Tunnel For Elevation |
| 994 | SV3-1220-CRW-CV1587 | UNIT 3 AUXILIARY BUILDING A3 (82'-6" TO 100'-0") INTERIOR WALL REBAR - AREAS 1 & 2 |
| 995 | SV3-CA01-S4W-CV4087 | CA01-33 PLP and Perm Weld Attachments |
| 996 | SV3-CA01-S4W-CV4077 | CA01-12 OVERLAY PLATES AND PERMANENT WELDED ATTACHMENTS |
| 997 | SV3-4032-ERW-EL6350 | INSTALLATION OF CONDUIT SLEEVES FOR RACEWAY WALL AND FLOOR PENETRATIONS, ANNEX BUILDING, AREA 2, EL. 100'-0" |
| 998 | SV3-CA01-S4W-CV4080 | CA01-16 OLP AND PERM WELD ATTACHMENTS |
| 999 | SV3-CA01-S4W-CV2153 | INSTALL CA01-09 PERMANENT WELDED ATTACHMENTS |
| 1000 | SV3-1220-CCW-CV1888 | PLACEMENT OF CONCRETE IN MISCELLANEOUS WALLS (16, 17, 18 AND 18A) UP TO ELEV 82'-6" |
| 1001 | SV3-CA01-MHW-CV2161 | LIFTING FRAMES AND BRACING SUBMODULES 04,11,12,17 THRU 19,25,47 & 48 |
| 1002 | SV3-1220-EGW-EL2438 | INSTALL GROUND CABLES & GROUND PLATE INSERTS FOR AUXILIARY BUILDING OUTER WALLS ELEVATION 82'-6" TO 100'-0" &EXTEND RISERS TO ELEVATION 100'-0" |
| 1003 | SV3-CA01-MHW-CV2163 | LIFTING FRAMES AND BRACING SUBMODULES 27 THRU 31, 34 & 46 |
| 1004 | SV3-1130-CEW-CV1596 | U3 CONTAINMENT CONCRETE EMBEDMENTS EL. 87FT-6IN |
| 1005 | SV3-1220-CEW-CV1606 | U3 AUXILIARY BUILDING EMBED PLATES-AREA 1-EL 82'-6" WALLS |
| 1006 | SV0-YFS-THW-ME2216 | HYDRO TEST YARD FIRE SYSTEM (YFS) FROM BUILDING 315 TO BUILDING 301 |
| 1007 | SV3-1130-C0W-CV4055 | REINFORCED CONCRETE INSIDE CONTAINMENT 87-6 TO 96-0 WEST SIDE (LAYERS 6V AND 7V) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1008 | SV4-FPS-P0W-ME7685 | Fabricate and Install the Unit 4 Phase 7 North Side Fire Protection System (FPS) piping in Isometrics (SV4-FPS-PLW-966,967,96AM,96AL) |
| 1009 | SV3-1220-EGW-EL3438 | INSTALL GROUNDING FOR SHIELD WALL ELEVATION 82'-6" TO 100'-0" |
| 1010 | SV3-1220-ERW-EL3779 | INSTALL CONDUIT SLEEVES FOR PENETRATIONS, UNIT 3 AUXILIARY BUILDING, ELEVATION 82'-6" AREAS 4 & 5, RM 12251 (SP-09), RM 12252 (SP-10), RM12261 (SP-11 & SP-13). |
| 1011 | SV3-1220-CEW-CV1607 | Auxiliary Building Embed Plates & Anchor Bolts-EL 82'6" Walls - Area 2 |
| 1012 | SV4-FPS-P0W-ME7686 | Fabricate and Install the Unit 4 Phase 7 South Side Fire Protection System (FPS) piping in Isometrics (SV4-FPS-PLW-964,965,96AK,96AW,96AX,96BA) |
| 1013 | SV4-1210-ERW-EL1808 | Unit 4 Auxiliary Builing grounding and sleeves for wall pours 14-18 |
| 1014 | SV3-CA20-ERW-EL0670 | Installation of Electrical Penetrations in Module CA20 |
| 1015 | SV3-1220-CCW-CV1483 | AUXILIARY BUILDING EXTERIOR WALLS UP TO ELEVATION 82'6" |
| 1016 | SV3-CA01-S4W-CV2244 | CA01-27 PERMANENT WELDED ATTACHMENTS |
| 1017 | SV3-1220-EGW-EL3098 | U3-AUXILIARY BUILDING INSTALL ELECTRICAL PENETRATIONS AND GROUNDING FOR WALLS EL 82' 6" TO 100' 0", AREAS 1 & 2 |
| 1018 | SV3-1100-ERW-EL1589 | CONTAIMENT BUILDING EX CORE INSTRUMENTATION EMDEDDED CONDUIT EL 71FT-6IN TO 107FT-2IN |
| 1019 | SV3-2053-SHW-EL7840 | Electrical Cable Tray Supplemental Steel Installation in the Turbine Building, Elevation 141'-3", Area 3 from Columns 19 to 20 & P.2 to R |
| 1020 | SV3-2053-SHW-EL7841 | Electrical Cable Tray Supplemental Steel Installation in the Turbine Building, Elevation 141'-3", Area 3 from Columns 19 to 20 & L.5 to P.2 |
| 1021 | SV3-WLS-PLW-ME0875 | FABRICATE AND INSTALL WLS PIPING ISOMETRIC# SV3-WLS-PLW-754 |
| 1022 | SV3-ME01-PLW-ME1020 | UNIT 3 CONDENSER A: INSTALLATION OF FLASHBOX PIPING |
| 1023 | SV3-WRS-PLW-ME0597 | WRS LARGE BORE PIPING INSTALLATION (INCLUDES ISOMETRIC SV3-WRS-PLW-655 AND 573) |
| 1024 | SV3-WWS-PLW-ME0610 | INSTALLATION OF LARGE BORE WWS PIPING (INCLUDING ISOMETRICS SV3-WWS-PLW-311, -315) |
| 1025 | SV3-WRS-PLW-ME0603 | WRS LARGE BORE PIPING INSTALLATION (INCLUDES ISOMETRICS SV3-WRS-PLW-571, 576, AND 57F) |
| 1026 | SV3-2020-PLW-ME1352 | INSTALL CONDENSATE PUMP SV3-CDS-MP-01C |
| 1027 | SV3-2020-PLW-ME1350 | INSTALL CONDENSATE PUMP SV3-CDS-MP-01A |
| 1028 | SV3-2020-PLW-ME1351 | INSTALL CONDENSATE PUMP SV3-CDS-MP 01B |
| 1029 | SV0-SDS-PLW-ME1566 | FABRICATE AND INSTALL SDS PIPING BETWEEN LIFT STATIONS MS-500 & MS-501. |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1030 | SV3-WRS-PLW-ME0601 | WRS LARGE BORE PIPING INSTALLATION (INCLUDES ISOMETRIC SV3-WRS-PLW-572, 574, 578, 579, AND 57D) |
| 1031 | SV0-YFS-PLW-ME1196 | FABRICATE AND INSTALL THE YARD FIRE WATER LINE FROM HEADER TO HYDRANT H-25. |
| 1032 | SV3-ME01-PLW-ME1110 | UNIT 3 CONDENSER B HOTWELL: HOTWELL PIPING |
| 1033 | SV3-WWS-PLW-ME1215 | UNIT 3 TURBINE BUILDING EL 100 FT. - 0 IN. EMBEDDED WWS PIPING PACKAGE # 4 |
| 1034 | SV3-ME01-PHW-ME1273 | CONDENSER A: FABRICATION & INSTALLATION OF 1ST EXTRACTION STEAM PIPING SUPPORTS |
| 1035 | SV3-CPS-P0W-ME3593 | INSTALLATION OF CPS PIPING |
| 1036 | SV3-WLS-PHW-ME0712 | FABRICATE AND INSTALL WLS CONSTRUCTION AID SUPPORTS FOR THE CONTAINMENT BUILDING EMBEDDED PIPE |
| 1037 | SV3-WLS-PLW-ME0689 | FABRICATE AND INSTALL WLS EMBEDDED PIPING SHOWN ON ISOMETRIC DRAWING SV3-WLS-PLW-785. |
| 1038 | SV3-ME01-PHW-ME1219 | CONDENSER C: VACUUM PIPING SUPPORTS |
| 1039 | SV3-HDS-PLW-ME1431 | CONNECT HEATER DRAIN PIPING TO NOZZLES |
| 1040 | SV3-ME01-MEW-ME0914 | UNIT 3 CONDENSERS A, B & C-INSTALLATION OF UPPER SHELL MANHOLES |
| 1041 | SV3-WLS-MTW-ME1032 | INSTALLATION OF MONITOR TANKS WLS-MT-07A AND WLS-MT-07B IN CA20 |
| 1042 | SV3-ME01-PHW-ME1284 | UNIT 3 CONDENSER C: FABRICATION & INSTALLATION OF 4TH EXTRACTION STEAM PIPING SUPPORTS |
| 1043 | SV4-KQ10-KQW-ME1683 | KQ10 REACTOR COOLANT DRAIN TANK (WLS-MT-01) INSTALLATION |
| 1044 | SV3-ME01-PHW-ME1277 | CONDENSER B: FABRICATION & INSTALLATION OF 1ST EXTRACTION STEAM PIPING SUPPORTS |
| 1045 | SV3-ML05-MLW-ME1712 | ATTACHMENT OF WELDED NELSON STUDS TO EMBEDDED PIPING PENETRATIONS 82'-6" FLOORS ONLY |
| 1046 | SV3-CES-PLW-ME1658 | FABRICATE AND INSTALL CONDENSER TUBE CLEANING SYSTEM (CES) PIPING IN TURBINE BUILDING ELEV. 82'-6 |
| 1047 | SV3-ME01-PLW-ME0986 | Condenser A: WWO Piping |
| 1048 | SV3-WRS-P0W-ME3669 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDING ISOMETRICS SV3-WRS-PLW-85C, 85D) |
| 1049 | SV3-ME01-PLW-ME0987 | CONDENSER B: WWO PIPING |
| 1050 | SV3-ME01-PLW-ME1007 | Condenser C: WWO Piping |
| 1051 | SV3-WWS-P0W-ME1839 | FABRICATE AND INSTALL WASTE WATER PIPING FROM UNIT 3 DIESEL GENERATOR BLDG. SUM TO THE OIL/WATER SEPARATOR. |
| 1052 | SV3-WLS-PLW-ME0513 | Installation of Small Bore WLS Piping (Includes: SV3-WLS-PLW-142,-33F,-216,-212) |
| 1053 | SV3-WLS-PLW-ME0588 | INSTALLATION OF WLS LARGE BORE PIPING (INCLUDING ISOMETRICS SV3-WLS-PLW-631) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1054 | SV3-HDS-PLW-ME1371 | FABRICATE/INSTALL OF HEATER DRAIN SMALL BORE PIPING ON FEEDWATER HEATER DRAIN COOLER 7C |
| 1055 | SV3-WRS-PLW-ME0589 | WRS LARGE BORE PIPING INSTALLATION (INCLUDES ISOMETRICS SV3-WRS-PLW-55A AND 55B) |
| 1056 | SV3-HDS-PHW-ME1362 | FABRICATE AND INSTALL HEATER DRAIN PIPE SUPPORTS ON FEEDWATER HEATER DRAIN COOLER 7A |
| 1057 | SV3-WLS-PLW-ME0585 | INSTALLATION OF WLS LARGE BORE PIPING (INCLUDING ISOMETRICS SV3-WLS-PLW-33A, 260). |
| 1058 | SV3-HDS-PLW-ME1363 | FABRICATE/INSTALL OF HEATER DRAIN SMALL BORE PIPING ON FEEDWATER HEATER DRAIN COOLER 7A |
| 1059 | SV3-ME01-PHW-ME1220 | Condenser A: WWO Piping Supports |
| 1060 | SV3-MSS-P0W-ME4659 | INSTALLATION OF MSS PIPING |
| 1061 | SV3-ME01-PHW-ME1221 | Condenser B: WWO Piping Supports |
| 1062 | SV3-ME01-PHW-ME1222 | Condenser C: WWO Piping Supports |
| 1063 | SV3-ML05-MLW-ME0711 | Installation of CA20 Penetration Sleeves |
| 1064 | SV3-SDS-CKW-ME1657 | INSTALL SANITARY DRAIN MANHOLES MH-58, MH-59, MH-60, MH-61, MH-68 & MH-69. |
| 1065 | SV3-WLS-PLW-ME0578 | Installation of Large Bore WLS Piping (Includes Isometrics SV3-WLS-PLW-680, -770, -790, -850) |
| 1066 | SV3-ME01-PLW-ME1535 | Unit 3 Condenser C: Installation of Water Curtain Piping |
| 1067 | SV3-WLS-PLW-ME0584 | Installation of WLS Large Bore Piping (Including Isometric SV3-WLS-PLW-215) |
| 1068 | SV3-DOS-P0W-ME1812 | FABRICATE AND INSTALL THE DIESEL FUEL OIL PIPING EAST OF UNIT 3 ANNEX. |
| 1069 | SV3-ME01-PLW-ME1164 | CONDENSER B-2ND EXTRACTION PIPING (EXTRACTION STEAM) |
| 1070 | SV3-ME01-PLW-ME1160 | CONDENSER A-2ND EXTRACTION PIPING (EXTRACTION STEAM) |
| 1071 | SV3-WLS-PLW-ME0521 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES ISOMETRICS SV3-WLS-PLW-66Y, 66Z, 601, 67A, 67R, 677, 68C) |
| 1072 | SV3-CCS-PLW-ME0490 | INSTALLATION OF SMALL BORE CCS PIPING (INCLUDES ISOMETRIC: SV3-CCS-PLW-331, 340) |
| 1073 | SV3-CDS-PHW-ME2305 | INSTALLATION OF CDS PIPING SUPPORTS (INCLUDES ISOMETRICS SV3-CDS-PLW-01AR, 01AQ,01AP) |
| 1074 | SV3-SDS-P0W-ME2418 | ANNEX BUILDING - ELEV. 100+ SDS PIPING PACKAGE #5 |
| 1075 | SV3-WWS-PHW-ME2428 | INSTALLATION OF ANNEX WWS PIPING SUPPORTS (FOR WP SV3-WWS-P0W-ME2279) |
| 1076 | SV3-CAS-P0W-ME2409 | FABRICATE AND INSTALL COMPRESSED AIR PIPING FROM UNIT 3 TURBINE BUILDING TO UNIT 3 TRANSFORMER AREA & DIESEL FUEL OIL SUMP PUMPS. |
| 1077 | SV3-SDS-P0W-ME2414 | ANNEX BUILDING - ELEV. 100+ SDS PIPING PACKAGE #1 |
| 1078 | SV3-WWS-P0W-ME2195 | FABRICATE AND INSTALL THE WASTE WATER PIPING TO THE UNIT 3 MT-10 TRANSFORMER AREA SUMP |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1079 | SV3-SDS-P0W-ME2417 | ANNEX BUILDING - ELEV. 100+ SDS PIPING PACKAGE #4 |
| 1080 | SV3-SDS-P0W-ME2415 | ANNEX BUILDING - ELEV. 100+ SDS PIPING PACKAGE #2 |
| 1081 | SV3-SDS-P0W-ME2421 | ANNEX BUILDING - ELEV. 127 + SDS PIPING PACKAGE |
| 1082 | SV3-SDS-P0W-ME2416 | ANNEX BUILDING - ELEV. 100+ SDS PIPING PACKAGE #3 |
| 1083 | SV3-DWS-PLW-ME0465 | INSTALLATION OF SMALL BORE DWS PIPING ( SV3-DWS-PLW-60D,624,625) |
| 1084 | SV3-DWS-PLW-ME0467 | DWS SML BORE PIPE INSTALLATION (SV3-DWS-PLW-62B) |
| 1085 | SV3-CCS-PLW-ME0493 | INSTALLATION OF SMALL BORE CCS PIPING (INCLUDES ISOMETRIC: SV3-CCS-PLW-609) |
| 1086 | SV3-HDS-PHW-ME1370 | FABRICATE AND INSTALL HEATER DRAIN SUPPORTS ON FEEDWATER HEATER DRAIN COOLER 7C |
| 1087 | SV3-PWS-PLW-ME1659 | FABRICATE AND INSTALL POTABLE WATER PIPING FROM UNIT 3 |
| 1088 | SV3-ML05-MLW-ME2410 | INSTALLATION OF CA20 FLOOR PENETRATIONS |
| 1089 | SV3-WLS-PHW-ME0767 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWINGS WLS-PLW-364, -870 |
| 1090 | SV3-VAS-PLW-ME0573 | Installation of Large Bore VAS Piping (includes Isometrics SV3-V AS-PLW-300) |
| 1091 | SV3-CVS-PLW-ME0559 | INSTALLATION OF LARGE BORE CVS PIPING (INCLUDES ISOMETRIC SV3-CVS-PLW-50D) |
| 1092 | SV0-YFS-PLW-ME1430 | REWORK POST INDICATOR VALVES |
| 1093 | SV3-WLS-PLW-ME0582 | INSTALLATION OF LARGE BORE WLS PIPING (INCLUDES ISOMETRIC: SV3-WLS-PLW-170) |
| 1094 | SV3-WLS-PLW-ME0587 | INSTALLATION OF WLS LARGE BORE PIPING (INCLUDING ISOMETRICS SV3-WLS-PLW-230, 390, 460, 710) |
| 1095 | SV3-WRS-P0W-ME2493 | FABRICATION AND INSTALLATION OF LARGE BORE WRS PIPING (ISOMETRIC SV3-WRS-PLW-56A, -56B, -56H) |
| 1096 | SV3-FPS-PLW-ME4841 | FABRICATE AND INSTALL FIRE PROTECTION SYSTEM (FPS) PIPING IAW (ISOMETRIC SV3-FPS-PLW-341) |
| 1097 | SV3-WLS-PLW-ME0519 | INSTALLATION OF SMALL BORE WLS PIPING. (INCLUDES: SV3-WLS-PLW-590) |
| 1098 | SV3-CCS-PLW-ME0494 | INSTALLATION OF SMALL BORE CCS PIPING (INCLUDES ISOMETRIC: SV3-CCS-PLW-610, 611), ISO 610 IS INSTALLED WITH R161 MODULE |
| 1099 | SV3-CDS-PHW-ME2307 | FABRICATION AND INSTALLATION OF CDS PIPING SUPPORTS FROM HEATER DRAIN COOLERS (ME-07A/B/C) TO MAIN CONDENSERS (ME-01A/B/C). |
| 1100 | SV3-WLS-PLW-ME0581 | INSTALLATION OF LARGE BORE WLS PIPING (INCLUDES ISOMETRIC: SV3-WLS-PLW-161) |
| 1101 | SV3-WLS-PLW-ME0583 | INSTALLATION OF WLS LARGE BORE PIPING (INCLUDING ISOMETRICS SV3-WLS-PLW-201, 206) |
| 1102 | SV3-WWS-PHW-ME2682 | INSTALLATION OF ANNEX WWS PIPING SUPPORTS (FOR WP SV3-WWS-P0W-ME2632) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1103 | SV3-PGS-PLW-ME0484 | INSTALLATION OF SMALL BORE PGS PIPING (INCLUDES ISOMETRICS SV3-PGS-PLW-123, -124, -129) |
| 1104 | SV3-SFS-PLW-ME0571 | INSTALLATION OF LARGE BORE SFS PIPING (INCLUDES ISOMETRICS SV3-SFS-PLW-610, -620) |
| 1105 | SV3-TCS-PHW-ME2394 | INSTALLATION OF TCS SUPPORTS FOR PIPELINE PACKAGE SV3-TCS-PLW-ME2393 |
| 1106 | SV3-TCS-PLW-ME2393 | Installation Of TCS Piping (Includes Isometrics SV3-TCS-PLW-73L, 73X, 721, 722, 730) |
| 1107 | SV3-WRS-P0W-ME3661 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES ISOMETRICS SV3-WRS-PLW-82A, 82B, 82C, 82D, 820, 821, 822, 823) |
| 1108 | SV3-CCS-P0W-ME2456 | Installation Of Small Bore CCS Piping (Includes Isometric: SV3-CCS-PLW-124) |
| 1109 | SV3-VWS-PLW-ME0575 | INSTALLATION OF LARGE BORE VWS PIPING (INCLUDES ISOMETRICS SV3-VWS-PLW-387, 487) |
| 1110 | SV3-WRS-PLW-ME0594 | Installation of Large Bore WRS Piping |
| 1111 | SV3-ME01-MEW-ME0993 | Unit 3 Condenser A: Installation of Feedwater Heaters, Associated Piping and Supports |
| 1112 | SV3-WWS-P0W-ME2193 | FABRICATE AND INSTALL THE WASTE WATER PIPING TO THE UNIT 3 MT-04 DIESEL FUEL OIL AREA SUMP |
| 1113 | SV3-CCS-P0W-ME2460 | INSTALLATION OF SMALL BORE CCS PIPING (INCLUDES ISOMETRIC: SV3-CCS-PLW-153) |
| 1114 | SV3-TCS-PLW-ME2399 | INSTALLATION OF TCS PIPING (INCLUDES ISOMETRICS SV3-TCS-PLW-830, 831, 832, 841, 842, 843, 844) |
| 1115 | SV3-CCS-P0W-ME2777 | Installation of Large Bore CCS Piping (Includes Isometrics SV3-CCS-PLW-120, 121, 122, 123) |
| 1116 | SV3-VWS-PHW-ME0700 | FABRICATION/INSTALLATION OF LARGE BORE VWS PIPING SUPPORTS FOR ISOMETRIC DRAWINGS SV3-VWS-PLW-260, -384 |
| 1117 | SV3-TCS-PLW-ME2407 | INSTALLATION OF TCS PIPING FOR ISOMETRICS SV3-TCS-PLW-920, SV3-TCS-PLW-921, SV3-TCS-PLW-922, SV3-TCS-PLW-923, SV3-TCS-PLW-924, SV3-TCS-PLW-925, SV3-TCS-PLW-926, SV3-TCS-PLW-927. |
| 1118 | SV3-TCS-PHW-ME2396 | INSTALLATION OF TCS SUPPORTS FOR ISOMETRICS: SV3-TCS-PLW-810, SV3-TCS-PLW-811 AND SV3-TCS-PLW-812. |
| 1119 | SV3-TCS-PLW-ME2395 | INSTALLATION OF TCS PIPING FROM ISOMETRICS: SV3-TCS-PLW-810, SV3-TCS-PLW-811, SV3-TCS-PLW-812, SV3-TCS-PLW-813, SV3-TCS-PLW-814, SV3-TCS-PLW-815, SV3-TCS-PLW-816, SV3-TCS-PLW-817, AND SV3-TCS-PLW-818. |
| 1120 | SV3-WLS-PLW-ME0533 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES ISOMETRICS SV3-WLS-PLW-611, -616) |
| 1121 | SV3-PWS-PHW-ME0793 | FABRICATION/INSTALLATION OF SMALL BORE PWS PIPING SUPPORTS FOR ISOMETRIC DRAWINGS SV3-PWS-PLW-91A,-911,-950,-951,-952,-953 |
| 1122 | SV3-TCS-PLW-ME2397 | INSTALLATION OF TCS PIPING FOR ISOMETRICS SV3-TCS-PLW-820, SV3-TCS-PLW-821, SV3-TCS-PLW-822, SV3-TCS-PLW-823, SV3-TCS-PLW-824, SV3-TCS-PLW-825, SV3-TCS-PLW-826. |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1123 | SV3-TCS-PLW-ME2403 | INSTALLATION OF TCS PIPING (INCLUDES ISOMETRICS SV3-TCS-PLW-870, 871, 872, 880, 881, 882, 883, 884) |
| 1124 | SV3-FPS-PHW-ME0694 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWINGS SV3-FPS-PLW-833 |
| 1125 | SV3-FPS-PLW-ME0561 | INSTALLATION OF LARGE BORE FPS PIPING (INCLUDES ISOMETRICS SV3-FPS-PLW-810, -815) |
| 1126 | SV3-VAS-PHW-ME0699 | INSTALLATION OF LARGE BORE VAS PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-VAS-PLW-300 |
| 1127 | SV3-CDS-PHW-ME2502 | INSTALLATION OF CDS SUPPORTS FOR ISOMETRICS SV3-CDS-PLW-720, SV3-CDS-PLW-721, SV3-CDS-PLW-724 |
| 1128 | SV3-WLS-P0W-ME3525 | INSTALLATION OF SMALL BORE WLS PIPING (ISOMETRIC SV3-WLS-PLW-050) |
| 1129 | SV3-WWS-PHW-ME3178 | ANNEX BUILDING - WWS SUPPORT ISOMETRIC 961 |
| 1130 | SV3-WWS-P0W-ME3177 | ANNEX BUILDING - WWS PIPING ISOMETRIC 961 |
| 1131 | SV3-WWS-PHW-ME2588 | INSTALL THE UNIT 3 TRANSFORMERS AREA SUMP PIPE SUPPORTS. |
| 1132 | SV3-CVS-P0W-ME3327 | ANNEX BUILDING - CHEMICAL & VOLUME CONTROL PIPING ISOMETRICS SV3-CVS-PLW-640, SV3-CVS-PLW-681, SV3-CVS-PLW-690, SV3-CVS-PLW-691, SV3-CVS-PLW-692, SV3-CVS-PLW-693. |
| 1133 | SV3-WRS-PLW-ME0592 | WRS LARGE BORE PIPING INSTALLATION (INCLUDES ISOMETRICS SV3-WRS-PLW-59W, 593, 59E, 59F AND 59X) |
| 1134 | SV3-2020-CCW-CV0129 | U3 TURBINE GROUTING ACTIVITIES BELOW 100' ELEVATION |
| 1135 | SV0-PWS-PLW-ME1082 | FABRICATE AND INSTALL POTABLE WATER PIPING BETWEEN BUILDING 301 TO BUILDING 304. |
| 1136 | SV3-WRS-PLW-ME1097 | INSTALLATION OF LARGE BORE WRS PIPING (INCLUDES ISOMETRICS SV3-WRS-PLW-662, -66A, -66C, -667, -66E) |
| 1137 | SV3-WLS-PLW-ME0527 | WLS SML BORE PIPE INSTALLATION (INCLUDES ISOMETRICS: SV3-WLS-PLW-90B, -904) |
| 1138 | SV3-WGS-P0W-ME0507 | INSTALLATION OF SMALL BORE WGS PIPING (INCLUDES SV3-WGS-PLW-545, 546) |
| 1139 | SV3-DTS-PHW-ME3588 | FABRICATION AND INSTALLATION OF DTS PIPING SUPPORT |
| 1140 | SV3-WLS-PLW-ME0512 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES: SV3-WLS-PLW-150) |
| 1141 | SV3-WLS-PLW-ME0511 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES: SV3-WLS-PLW-140, SV3-WLS-PLW-14E) |
| 1142 | SV4-1200-Z0W-CV3910 | UNIT 4 AUXILIARY BUILDING REINFORCED CONCRETE REQUIREMENTS |
| 1143 | SV3-WLS-PLW-ME0530 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDING ISOMETRICS: SV3-WLS-PLW-35A, -35C) |
| 1144 | SV3-MS08-MEW-ME3567 | INSTALLATION OF DWS CORS FEED PUMP (DWS-MP-02) |

# Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1145 | SV3-MS25-MEW-ME3555 | INSTALLATION OF CVS ZINIC INJECTION SKID (CVS-MS-01) |
| 1146 | SV3-1220-CCW-CV3386 | UNIT 3 AUXILIARY BUILDING FLOORS AREAS 3 THRU 6- CONCRETE PLACEMENT AT ELEV.82"-6" (SLAB PLACEMENT #8 THRU #15) |
| 1147 | SV3-WWS-PLW-ME0615 | INSTALLATION OF LARGE BORE WWS PIPING (INCLUDES ISOMETRICS (SV3-WWS-321, 322) |
| 1148 | SV3-ME01-MEW-ME0995 | Unit 3 Condenser B: Installation of Feedwater Heaters, Associated Piping and Supports |
| 1149 | SV3-ME01-PHW-ME1279 | CONDENSER B: FABRICATION & INSTALLATION OF 3RD EXTRACTION STEAM PIPING SUPPORTS |
| 1150 | SV3-ME01-PHW-ME1280 | Unit 3 Condenser B: Fabrication of 4th Extraction Steam Piping Supports |
| 1151 | SV3-ME01-PHW-ME1281 | Unit 3 Condenser C: Fabrication of 1st Extraction Steam Piping Supports |
| 1152 | SV3-ME01-PHW-ME1283 | CONDENSER C: FABRICATION OF 3RD EXTRACTION STEAM PIPING SUPPORTS |
| 1153 | SV3-SWS-PLW-ME1356 | INSTALLATION OF SWS LARGE BORE PIPING (INCLUDES ISOMETRICS SV3-SWS-PLW-032, 033, 036, 037, 038, 039, 040, 050, 067, 069) |
| 1154 | SV3-CA05-CRW-CV2259 | FABRICATION OF REBAR FOR CA05 MODULE |
| 1155 | SV3-0000-CCW-CV2127 | UNIT 3 ISOLATED PHASE BUS DUCT AND NON-SEGMENTED PHASE BUS DUCT CONCRETE FOUNDATION |
| 1156 | SV3-CB00-S8W-CV1734 | Final Installation of Modules CB65 and CB66 |
| 1157 | SV3-ME2W-MEW-ME1358 | Installation of HDS Drain Cooler CDS-ME-7A |
| 1158 | SV3-2020-MEW-ME1488 | Unit 3 Condenser A Installation (Lower & Upper Shell) |
| 1159 | SV3-2020-MEW-ME1489 | Unit 3 Condenser B Installation (Lower & Upper Shell) |
| 1160 | SV3-MS60-MEW-ME1602 | Install Auxiliary Steam Boiler (ASS-MB-01) |
| 1161 | SV3-1220-CEW-CV1604 | AUXILIARY BUILDING EMBEDS AND ANCHOR BOLTS - ELEVATION 82'-6" - AREAS 3 AND 4 |
| 1162 | SV3-1210-CEW-CV1617 | AUXILIARY BUILDING EMBEDMENTS-CYLINDRICAL WALL-EL. 66'-6" |
| 1163 | SV3-MS60-MEW-ME1651 | Installation of ASS Boiler Make-up Pump (ASS-MP-01A & 01B) |
| 1164 | SV3-WRS-PLW-ME0608 | INSTALLATION OF LARGE BORE WRS PIPING (INCLUDES ISOMETRICS SV3-WRS-PLW-53D) |
| 1165 | SV3-1120-CCW-CV1816 | PLACEMENT, CURING, AND REPAIR OF CONCRETE INSIDE THE CV UP TO ELEV 76'-6" |
| 1166 | SV3-ECS-ERW-EL1843 | INSALLATION OF ELECTRICAL UNDERGROUND COMMODITIES (MANHOLES AND DUCT BANKS) FOR THE (ECS) MAIN AC POWER SYSTEM FROM NORTH OF DIESEL GENERATOR BLDG. TO DIESEL FUEL STORAGE TANKS - PHASE 2 |
| 1167 | SV3-WRS-P0W-ME2233 | ANNEX BUILDING - EMBEDDED WRS PIPING PACKAGE #1 |
| 1168 | SV3-WWS-P0W-ME2632 | Annex Building - Elevation 100+ WWS Piping #1 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1169 | SV3-DWS-P0W-ME3337 | FABRICATE AND INSTALL DEMINERALIZED WATER PIPING IAW SV3-DWS-PLW-130, SV3-DWS-PLW-131 |
| 1170 | SV3-DWS-P0W-ME3338 | FABRICATE AND INSTALL DEMINERALIZED WATER PIPING IAW SV3-DWS-PLW-101, SV3-DWS-PLW-150, SV3-DWS-PLW-247 |
| 1171 | SV3-2030-EGW-EL0980 | Electrical Grounding Installation for Turbine Building at Elevation 100'-9" |
| 1172 | SV3-1211-ERW-EL1619 | INSTALL DESIGN ROUTED RACEWAY AND SUPPORTS FOR DIVISION "B" BATTERY ROOM EL.66'-6" |
| 1173 | SV3-1211-ERW-EL1621 | INSTALL DESIGN ROUTED RACEWAY AND SUPPORTS FOR DIVISION "D" BATTERY ROOM EL. 66'-6" |
| 1174 | SV3-DWS-PLW-ME1711 | FABRICATE AND INSTALL DEMIN WATER PIPING FROM THE UNIT 3 ANNEX BLDG. TO THE DEMIN WATER STORAGE TANK. |
| 1175 | SV3-SWS-PLW-ME1494 | INSTALLATION OF SWS LARGE BORE PIPING (INCLUDES ISOMETRICS SV3-SWS-PLW-073, 079, 07E) |
| 1176 | SV3-SWS-PLW-ME1496 | INSTALLATION OF SWS LARGE BORE PIPING (INCLUDES ISOMETRICS SV3-SWS-PLW-074, 075, 076, 077, 07C, 07D) |
| 1177 | SV3-HDS-PLW-ME1365 | FABRICATE AND INSTALL HEATER DRAIN PIPING ON FEEDWATER HEATER DRAIN COOLER 7B |
| 1178 | SV3-HDS-PLW-ME1369 | FABRICATE AND INSTALL HEATER DRAIN PIPING ON FEEDWATER HEATER DRAIN COOLER 7C |
| 1179 | SV3-ME01-PHW-ME1218 | Condenser B: Vacuum Piping Supports |
| 1180 | SV3-MS13-MSW-ME1614 | Installation of CES Equipment (Ball Collector Skids, Ball Recirculation Pump Skids, Ball Distributors, & Ball Injectors) |
| 1181 | SV3-TCS-PLW-ME1059 | UNIT 3 TURBINE BUILDING EL. 82FT.-9IN. INSTALLATION OF TCS PIPING, VALVES, AND THERMOWELLS |
| 1182 | SV3-TCS-PHW-ME1061 | Unit 3 Turbine Building EL.82'-9" Installation of TCS Piping Supports |
| 1183 | SV3-FPS-PLW-ME0563 | INSTALLATION OF LARGE BORE FPS PIPING (INCLUDES ISOMETRICS SV3-FPS-PLW-820, -825, -830) |
| 1184 | SV3-ME01-PHW-ME1217 | Condenser A: Vacuum Piping Supports |
| 1185 | SV3-WWS-PLW-ME0614 | INSTALLATION OF LARGE BORE WWS PIPING (INCLUDES ISOMETRICS SV3-WWS-PLW-01B, -01D, -014) |
| 1186 | SV3-WWS-PLW-ME0613 | INSTALLATION OF LARGE BORE WWS PIPING |
| 1187 | SV3-ASS-PHW-ME1429 | FABRICATE/INSTALL AUXILIARY STEAM SYSTEM (ASS) SUPPORTS (PORTION 2) FOR ISOMETRIC# SV3-ASS-PLW-028, 02K, 2J, & 02A |
| 1188 | SV3-WLS-PLW-ME0517 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES: SV3-WLS-PLW-376, SV3-WLS-PLW-380) |
| 1189 | SV3-WLS-PLW-ME0516 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES:SV3-WLS-PLW-370 & SV3-WLS-PLW-375) |
| 1190 | SV3-ME01-PHW-ME1451 | Unit 3 Condenser C: Fabrication & Installation of Casing Drain Piping Supports |
| 1191 | SV3-2030-CCW-CV1464 | Unit 3 Turbine Building West Stair Foundations |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1192 | SV3-DTS-PLW-ME1511 | Fabricate and Install Demineralized Water Treatment System (DTS) piping portion 1-(Raw Water Supply to DTS-MS-01) |
| 1193 | SV3-1220-CCW-CV1487 | MISCELLANEOUS WALLS UP TO ELEV. 82'-6" |
| 1194 | SV3-ASS-PHW-ME1521 | FABRICATE/INSTALL OF AUXILIARY STEAM (ASS) SUPPORTS (PORTION 3) FOR ISOMETRIC# SV3-ASS-PLW-02X, 02G, 02M, & 02F |
| 1195 | SV3-HDS-PLW-ME1361 | FABRICATE AND INSTALL HEATER DRAIN PIPING ON FEEDWATER HEATER DRAIN COOLER 7A |
| 1196 | SV3-ME01-PHW-ME1449 | Unit 3 Condenser A: Fabrication & Installation of Casing Drain Piping Supports |
| 1197 | SV3-KB13-KBW-ME0422 | KB13 Sump (WRS-MT-01) Installation - Portion 2 Only |
| 1198 | SV3-MS60-MEW-ME1643 | Installation of ASS Boiler Blowdown Flash Tank (ASS-MT-01) |
| 1199 | SV3-WRS-PLW-ME0599 | WRS LARGE BORE PIPING INSTALLATION (INCLUDES ISOMETRIC SV3-WRS-PLW-57M AND 57N) |
| 1200 | SV3-WSS-PLW-ME0488 | FABRICATION/INSTALLATION OF SMALL BORE WSS PIPING (INCLUDES ISOMETRIC SV3-PLW-WSS-650) |
| 1201 | SV4-2101-CRW-CV5804 | UNIT 4, TURBINE BUILDING, FIRST BAY WALL FORMSAVERS AT 117'6" ELEVATION |
| 1202 | SV3-MS21-MSW-ME3153 | INSTALLATION OF SAMPLE RECOVERY TANK SKID, SSS-MS-05 |
| 1203 | SV3-SFS-P0W-ME4349 | INSTALLATION OF LARGE BORE SFS PIPING (INCLUDES SV3-SFS-PLW-150) |
| 1204 | SV3-CWS-PHW-ME2534 | INSTALLATION OF CWS SUPPORTS FOR ISO'S SV3-CWS-PLW-72J, SV3-CWS-PLW-73J, SV3-CWS-PLW-735, SV3-CWS-PLW-736 |
| 1205 | SV3-CWS-PLW-ME2533 | INSTALLATION OF CWS PIPING FOR ISO'S SV3-CWS-PLW-72J, SV3-CWS-PLW-73J, SV3-CWS-PLW-735, & SV3-CWS-PLW-736 |
| 1206 | SV3-1210-ERW-EL1071 | U3-AUX BLDG EL 66'-6"-CONDUIT SLEEVE WORK PACKAGE FOR WALL 20A |
| 1207 | SV3-1225-EYW-EL1755 | INSTALL CONDUIT SLEEVES FOR PENETRATION (12271-ML-E01 & 12271-ML-E02), UNIT 3 AUXILIARY BUILDING, ELEVATION 82'-6", AREA 5... |
| 1208 | SV3-1210-EGW-EL1720 | U3 GROUNDING SHIELD BUILDING WALLS EL 66'-6" TO 82'-6" |
| 1209 | SV3-1212-ERW-EL1620 | INSTALL DESIGN ROUTED RACEWAY AND SUPPORTS FOR DIVISION "C" BATTERY ROOM EL. 66'6" |
| 1210 | SV3-FPS-PLW-ME4902 | FABRICATE AND INSTALL ANNEX FIRE PROCTECTION SYSTEM( FPS) PIPING IAW (ISOMETRICS SV3-FPS-PLW-292,293) |
| 1211 | SV3-ML05-MLW-ME5928 | INSTALLATION OF CA35 PENETRATIONS |
| 1212 | SV4-CA01-S4W-CV8688 | CA01-10 TEMPORARY ATTACHMENT INSTALLATIONS |
| 1213 | SV3-WWS-CCW-CV6128 | WASTE WATER RETENTION BASIN WALL CONCRETE |
| 1214 | SV3-WWS-CRW-CV6129 | WASTE WATER RETENTION BASIN WALL REINFORCEMENT |
| 1215 | SV4-CA01-S4W-CV8720 | CA01-43 TEMPORARY ATTACHMENT INSTALLATIONS |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1216 | SV4-CA01-S4W-CV8719 | CA01-42 TEMPORARY ATTACHMENT INSTALLATIONS |
| 1217 | SV3-4030-CCW-CV5232 | UNIT 3 ANNEX BUILDING MISCELLANEOUS GROUTING AT ELEVATION 100'-0" |
| 1218 | SV3-FPS-PHW-ME4842 | INSTALLATION OF ANNEX BLDG FPS PIPE SUPPORTS (ISOMETRICS SV3-FPS-PLW-341) |
| 1219 | SV3-DWS-PHW-ME6990 | INSTALLATION OF ANNEX BLDG DWS PIPE SUPPORTS (ISOMETRICS SV3-PWS-PLW-203, 204, 237, 238) |
| 1220 | SV3-1120-SSW-CV1594 | CONTAINMENT STRUCTURAL STEEL AT ELEVATION 84'-6" |
| 1221 | SV3-FWS-P0W-ME3706 | INSTALLATION OF NON-EMBEDDED FWS DRAIN PIPING |
| 1222 | SV0-YFS-THW-ME3152 | FLUSH AND HYDRO TEST THE YARD FIRE SYSTEM (YFS) AT THE 300 BUILDINGS |
| 1223 | SV3-FWS-PHW-ME3707 | INSTALLATION OF NON-EMBEDDED FWS PIPE SUPPORTS |
| 1224 | SV3-CWS-PHW-ME2530 | INSTALLATION OF CWS PIPING SUPPORTS |
| 1225 | SV3-CCS-PLW-ME0497 | INSTALLATION OF SMALL BORE CCS PIPING (INCLUDES ISOMETRIC: SV3-CCS-PLW-523) |
| 1226 | SV3-WRS-PHW-ME0779 | INSTALLATION OF LARGE BORE WRS PIPING SUPPORTS: SV3-WRS-PH-12R0020, 12R0021 |
| 1227 | SV3-PWS-PHW-ME0792 | INSTALLATION OF SMALL BORE PWS PIPING SUPPORTS (INCLUDES ISOMETRIC SV3-PWS-PLW-307) |
| 1228 | SV3-FPS-PLW-ME0562 | INSTALLATION OF LARGE BORE FPS PIPING (INCLUDES ISOMETRICS SV3-FPS-PLW-832, -833) |
| 1229 | SV3-VAS-PLW-ME0572 | INSTALLATION OF LARGE BORE VAS PIPING (INCLUDES ISOMETRICS SV3-VAS-PLW-310, -330) |
| 1230 | SV3-PWS-PLW-ME0480 | PWS SML BORE PIPE INSTALLATION (INCLUDES ISOMETRICS SV3-PWS-PLW-921, -924) |
| 1231 | SV3-WRS-PHW-ME0780 | INSTALLATION OF LARGE BORE WRS PIPING SUPPORTS: SV3-WRS-PH-12R0024, 12R0064 |
| 1232 | SV3-WRS-PLW-ME0591 | WRS LARGE BORE PIPING INSTALLATION (INCLUDES ISOMETRIC SV3-WRS-PLW-55D) |
| 1233 | SV3-RNS-PLW-ME0569 | INSTALLATION OF RNS LARGE BORE PIPING (INCLUDES ISOMETRIC SV3-RNS-PLW-09B) |
| 1234 | SV3-KQ11-KQW-ME0567 | INSTALL MECHANICAL EQUIPMENT MODULE KQ11 (MP-02A, MP-02B)-PORTION 2 |
| 1235 | SV3-WRS-PHW-ME0778 | INSTALLATION OF LARGE BORE WRS PIPING SUPPORTS: SV3-WRS-PH-12R0004, 12R0802, 12R0809 |
| 1236 | SV3-WLS-PLW-ME0536 | Installation of Large Bore FPS Piping (Includes Isometrics SV3-WLS-PLW-33D) |
| 1237 | SV3-PWS-PHW-ME0795 | INSTALLATION OF SMALL BORE PWS PIPE SUPPORTS FOR ISOMETRIC SV3-PWS-PLW-923 |
| 1238 | SV3-PWS-PLW-ME0478 | INSTALLATION OF SMALL BORE PWS PIPING (INCLUDES ISOMETRIC SV3-PWS-PLW-307) |
| 1239 | SV3-FPS-PLW-ME0564 | INSTALLATION OF LARGE BORE FPS PIPING (INCLUDES ISOMETRICS SV3-FPS-PLW-720, -723, -724, -725) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1240 | SV3-RNS-PLW-ME0565 | INSTALLATION OF RNS LARGE BORE PIPING (INCLUDES ISOMETRIC SV3-RNS-PLW-09A) |
| 1241 | SV3-CCS-PLW-ME0491 | INSTALLATION OF SMALL BORE CCS PIPING (INCLUDES ISOMETRIC: SV3-CCS-PLW-522, 540) |
| 1242 | SV3-WLS-PLW-ME0532 | INSTALLATION OF WLS SMALL BORE PIPING (INCLUDES ISOMETRICS SV3-WLS-PLW-480, -482, -484) |
| 1243 | SV3-WLS-PLW-ME0529 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES ISOMETRICS SV3-WLS-PLW-355, -357, -359, -35M) |
| 1244 | SV3-CAS-PLW-ME0460 | INSTALLATION OF SMALL BORE CAS PIPING (INCLUDES ISOMETRICS: SV3-CAS-PLW-501, & 504) |
| 1245 | SV3-CCS-PLW-ME0489 | INSTALLATION OF SMALL BORE CCS PIPING (INCLUDES ISOMETRIC: SV3-CCS-PLW-302) |
| 1246 | SV3-PWS-PHW-ME0794 | FABRICATION/INSTALLATION OF SMALL BORE PWS PIPING SUPPORTS FOR ISOMETRIC DRAWING SV3-PWS-PLW-924 |
| 1247 | SV3-SFS-PHW-ME0809 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-SFS-PLW-653, 655 |
| 1248 | SV3-WRS-PLW-ME0609 | INSTALLATION OF LARGE BORE WRS PIPING (INCLUDES ISOMETRICS SV3-WRS-PLW-66D, -666, -66B) |
| 1249 | SV3-WRS-PHW-ME0777 | INSTALLATION OF LARGE BORE WRS PIPING SUPPORTS: SV3-WRS-PH-12R4030 |
| 1250 | SV3-WLS-PLW-ME0579 | Installation of Large Bore FPS Piping (Includes Isometrics: SV3-WRS-PLW-870, -364) |
| 1251 | SV3-DWS-PLW-ME0466 | DWS SML BORE PIPE INSTALLATION (SV3-DWS-PLW-626,627) |
| 1252 | SV3-WGS-P0W-ME0509 | INSTALLATION OF SMALL BORE WGS PIPING (INCLUDES SV3-WGS-PLW-544) |
| 1253 | SV3-WRS-PLW-ME0590 | WRS LARGE BORE PIPING INSTALLATION (INCLUDES ISOMETRIC SV3-WRS-PLW-55C) |
| 1254 | SV3-PSS-PLW-ME0482 | INSTALLATION OF SMALL BORE PSS PIPING (INCLUDING ISOMETRICS SV3-PSS-PLW-700 AND 701) |
| 1255 | SV3-PWS-PLW-ME0476 | INSTALLATION OF SMALL BORE PWS PIPING (INCLUDING ISOMETRIC SV3-PWS-PLW-060) |
| 1256 | SV3-WRS-PHW-ME0676 | INSTALLATION OF LARGE BORE WRS PIPE SUPPORT (INCLUDING DRAWING WRS-PH-12A0084) |
| 1257 | SV3-WLS-PLW-ME0522 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES ISOMETRICS SV3-WLS-PLW-664, 67M, 67Z, 67Y, 67J, 671) |
| 1258 | SV3-CCS-PHW-ME0806 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-CCS-PLW-521 |
| 1259 | SV3-WRS-PHW-ME0776 | INSTALLATION OF LARGE BORE WRS PIPING SUPPORTS: SV3-WRS-PH-12R0045 |
| 1260 | SV3-PGS-PLW-ME0483 | INSTALLATION OF SMALL BORE PGS PIPING (INCLUDES ISOMETRICS SV3-PGS-PLW-100, -105, -128) |
| 1261 | SV3-WWS-PLW-ME0611 | INSTALLATION OF LARGE BORE WWS PIPING INCLUDING ISOMETRICS SV3-WWS-PLW-31B, 31F |
| 1262 | SV3-VWS-PLW-ME0576 | INSTALLATION OF LARGE BORE VWS PIPING (INCLUDES ISOMETRICS SV3-VWS-PLW-384, 389, 260) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1263 | SV3-PWS-PLW-ME0479 | INSTALLATION OF SMALL BORE PWS PIPING (INCLUDES ISOMETRIC SV3-PWS-PLW-91A, 911, 950, 951, 953) |
| 1264 | SV3-ME01-PLW-ME1009 | Unit 3 Condenser B: Installation of Upper Shell Nozzles |
| 1265 | SV3-ME01-MEW-ME0997 | Unit 3 Condenser C: Installation of Feedwater Heaters |
| 1266 | SV3-VWS-PLW-ME0577 | INSTALLATION OF LARGE BORE VWS PIPING (INCLUDES ISOMETRICS SV3-VWS-PLW-270, 484, 489) |
| 1267 | SV3-WLS-PLW-ME0515 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES: SV3-WLS-PLW-265, SV3-WLS-PLW-275) |
| 1268 | SV3-WLS-PLW-ME0937 | Fabricate and Install Small Bore Elevation WLS Piping ISO SV3-WLS-PLW-042, 45, 46, and 4B |
| 1269 | SV3-CCS-PHW-ME0804 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-CCS-PLW-611 |
| 1270 | SV3-WLS-PLW-ME0518 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES: SV3-WLS-PLW-490) |
| 1271 | SV3-WRS-PLW-ME0605 | INSTALLATION OF LARGE BORE WRS PIPING (INCLUDES ISOMETRICS SV3-WRS-PLW-577, -57C) |
| 1272 | SV3-WRS-PLW-ME0593 | WRS LARGE BORE PIPING INSTALLATION (INCLUDES ISOMETRIC SV3-WRS-PLW-59K, 59N, 59U, 59J, AND 59Q) |
| 1273 | SV3-PWS-PLW-ME0481 | INSTALLATION OF SMALL BORE PWS PIPING (INCLUDES ISOMETRIC SV3-PWS-PLW-923) |
| 1274 | SV3-ME01-PLW-ME1448 | UNIT 3 CONDENSER C: FABRICATION & INSTALLATION OF CASING DRAIN PIPING |
| 1275 | SV3-ME01-PLW-ME1447 | UNIT 3 CONDENSER B: FABRICATION & INSTALLATION OF CASING DRAIN PIPING |
| 1276 | SV3-ME01-PLW-ME1168 | CONDENSER C-2ND EXTRACTION PIPING (EXTRACTION STEAM) |
| 1277 | SV3-WWS-PHW-ME1376 | INSTALLATION OF LARGE BORE WWS PIPING SUPPORTS (INCLUDES ISOMETRICS SV3-WWS-PLW-014) |
| 1278 | SV3-RNS-PLW-ME1373 | INSTALLATION OF RNS LARGE BORE PIPING (INCLUDES ISOMETRIC SV3-RNS-PLW-090) |
| 1279 | SV3-WRS-PLW-ME1183 | WRS PIPING INSTALLATION (INCLUDES ISOMETRICS SV3-WRS-PLW-544, SPOOL 2) |
| 1280 | SV3-ME01-PHW-ME1537 | UNIT 3 CONDENSER B: INSTALLATION OF WATER CURTAIN SPRAY PIPING SUPPORTS |
| 1281 | SV3-ME01-PHW-ME1538 | UNIT 3 CONDENSER C: INSTALLATION OF WATER CURTAIN SPRAY PIPING SUPPORTS |
| 1282 | SV3-HDS-PLW-ME1367 | FABRICATE/INSTALL OF HEATER DRAIN SMALL BORE PIPING ON FEEDWATER HEATER DRAIN COOLER 7B |
| 1283 | SV3-WLS-THW-ME1469 | ASME SECTION III - HYDROSTATIC TEST PACKAGE FOR ISOMETRIC# SV3-WLS-PLW-731 LINE# WLS-PL-L062, -113B BETWEEN WLS-PL-V071B AND WLS-PL-V072B |
| 1284 | SV3-WRS-PLW-ME0595 | WRS LARGE BORE PIPING INSTALLATION (INCLUDES ISOMETRIC SV3-WRS-PLW-59A) |
| 1285 | SV3-KB10-KBW-ME0421 | KB10 SUMP (WWS-MT-06) INSTALLATION - PORTION 2 ONLY |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1286 | SV4-FPS-P0W-ME7089 | INSTALLATION OF LARGE BORE FPS PIPING (INCLUDES ISOMETRICS: SV4-FPS-PLW-811, 812, 831) |
| 1287 | SV3-SFS-PLW-ME0570 | INSTALLATION OF KB12 SFS LARGE BORE PIPING (INCLUDES ISOMETRICS SV3-SFS-PLW-460, -480) |
| 1288 | SV3-VWS-P0W-ME7195 | INSTALLATION OF ANNEX BLDG VWS PIPING (ISOMETRICS SV3-VWS-PLW-201, -203, -211, & -213) |
| 1289 | SV3-CWS-PHW-ME2506 | INSTALLATION OF PIPE SUPPORTS ON ISO SV3-CWS-PLW-737 |
| 1290 | SV3-CA20-Z0W-CV3913 | UNIT 3 CA20 CONCRETE REQUIREMENTS |
| 1291 | SV3-VWS-P0W-ME7197 | INSTALLATION OF ANNEX BLDG VWS PIPING (ISOMETRICS SV3-VWS-PLW-221, -223, -231, & -233) |
| 1292 | SV4-WGS-THW-ME7481 | HYDRO TESTING OF KB14 WGS PIPING |
| 1293 | SV4-VWS-P0W-ME7482 | INSTALLATION OF KB14 VWS PIPING |
| 1294 | SV4-VWS-PHW-ME7483 | INSTALLATION OF KB14 VWS PIPE SUPPORTS |
| 1295 | SV4-VWS-THW-ME7484 | HYDRO TESTING OF KB14 VWS PIPING |
| 1296 | SV4-WLS-THW-ME7490 | HYDRO TESTING OF KB16 WLS PIPING |
| 1297 | SV4-WGS-THW-ME7493 | HYDRO TESTING OF KB16 WGS PIPING |
| 1298 | SV4-VWS-THW-ME7496 | HYDRO TESTING OF KB16 VWS PIPING |
| 1299 | SV4-DWS-THW-ME7499 | HYDRO TESTING OF KB16 DWS PIPING |
| 1300 | SV4-MP07-MPW-ME7111 | INSTALLATION OF THE FWS STARTUP PUMPS (FWS-MP-03A, FWS-MP-03B) |
| 1301 | SV3-DWS-P0W-ME7193 | INSTALLATION OF ANNEX BLDG DWS PIPING (ISOMETRICS SV3-DWS-PLW-210, -220) |
| 1302 | SV3-WRS-P0W-ME3662 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES ISOMETRICS SV3-WRS-PLW-82E, 82F, 82G, 82K, 825, 826, 827, 828) |
| 1303 | SV3-SFS-PLW-ME0499 | INSTALLATION OF SMALL BORE SFS PIPING (INCLUDES SV3-SFS-PLW-653, 655) |
| 1304 | SV3-CA01-S5W-CV4287 | SUB-MODULES CA01-16 & CA01-34 CLOSEOUT WORK |
| 1305 | SV3-ES03-ESW-EL7414 | MOUNTING OF THE UNIT 3 TURBINE BUILDING MAIN GENERATOR CIRCUIT BREAKERS |
| 1306 | SV4-WRS-P0W-ME5363 | FABRICATION/INSTALLATIN OF SMALL BORE WRS LEAK CHASE PIPING INCLUDING SV4-WRS-PLW-81F, 82A, 82B, 82C, 820, 821, 822, 823 |
| 1307 | SV4-2000-Z0W-CT7540 | U4 TURBINE BUILDING COATING REQUIREMENTS |
| 1308 | SV3-VWS-P0W-ME7201 | INSTALLATION OF ANNEX BLDG VWS PIPING (ISOMETRICS SV3-VWS-PLW-140, -141, -150, & -151) |
| 1309 | SV3-CCS-P0W-ME7199 | INSTALLATION OF ANNEX BLDG CCS PIPING (ISOMETRICS SV3-CCS-PLW-830, -840) |
| 1310 | SV3-CA01-S4W-CV3345 | CA01-24 OVERLAY PLATES AND ATTACHMENTS |
| 1311 | SV3-CA01-S4W-CV3233 | CA01-02 OVERLAY PLATES AND ATTACHMENTS |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1312 | SV3-CA01-S4W-CV3382 | CA01-23 OVERLAY PLATES AND ATTACHMENTS |
| 1313 | SV3-CA01-S4W-CV4085 | CA01-21 OLP AND PERM WELD ATTACHMENTS |
| 1314 | SV3-CA01-S4W-CV4084 | CA01-20 OLP AND PERMANMENT WELDED ATTACHMENTS |
| 1315 | SV3-CA01-S4W-CV4086 | INSTALL CA01-32 PERMANENT WELDED ATTACHMENTS |
| 1316 | SV3-1130-EGW-EL7575 | GROUNDING OF CONTAINMENT AND SHIELD WALL 100'-135' |
| 1317 | SV3-G100-XBW-CV7687 | INSTALLATION OF HDPE WATER BARRIER U3 (REMAINING INSTALLATION) |
| 1318 | SV3-0000-CCW-CV7737 | Unit 3 Fire Water Storage Tank |
| 1319 | SV4-0000-CCW-CV7738 | Unit 4 Fire Water Storage Tank |
| 1320 | SV3-4033-CCW-CV7518 | ANNEX BUILDING AREA 3 TOWER FOUNDATION |
| 1321 | SV3-FWS-THW-ME1390 | UNIT 3 TURBINE BUILDING EL 100'-0" HYDROSTATIC TESTING OF EMBEDDED FWS PIPING |
| 1322 | SV3-ME01-PHW-ME1276 | UNIT 3 CONDENSER A: FABRICATION & INSTALLATION OF 4TH EXTRACTION PIPING SUPPORTS |
| 1323 | SV3-ME01-PHW-ME1275 | CONDENSER A: FABRICATION & INSTALLATION OF 3RD EXTRACTION STEAM PIPING SUPPORTS |
| 1324 | SV3-ME01-PLW-ME0999 | UNIT 3 CONDENSER C: INSTALLATION OF HEATER 3A, 3B, 4A & 4B SHELL VENT PIPING |
| 1325 | SV3-WWS-PLW-ME0910 | UNIT 3 TURBINE BUILDING EL 100FT.-0IN. BAY 1 WWS EMBEDDED PIPING PACKAGE # 1 |
| 1326 | SV3-WRS-PLW-ME0602 | WRS LARGE BORE PIPING INSTALLATION (INCLUDES ISOMETRICS SV3-WRS-PLW-57B, 575, AND 57E) |
| 1327 | SV3-SFS-PHW-ME4491 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-SFS-PLW-150 |
| 1328 | SV0-0000-P0W-ME8898 | INSTALLATION OF CONSTRUCTION AID MUD MAT |
| 1329 | SV4-2040-CEW-CV8875 | UNIT 4, TURBINE BUILDING, 120' ELEVATED SLAB #5, ELEC/MECH PENETRATION SLEEVES |
| 1330 | SV4-2040-CEW-CV8876 | UNIT 4, TURBINE BUILDING, 120' ELEVATED DECK, SLEEVES - POUR #6 |
| 1331 | SV3-4041-SAW-EL8773 | INSTALL SUPPLEMENTAL STEEL FOR ELECTRICAL HANGERS COL LN F9/F11.09 TO E9/E11.09 |
| 1332 | SV3-MP1J-MEW-ME3694 | INSTALLATION OF CCS PUMPS (CCS-MP-01A, CCS-MP-01B) |
| 1333 | SV3-MSS-P0W-ME4649 | INSTALLATION OF MSS PIPING |
| 1334 | SV4-FPS-P0W-ME7378 | FABRICATE AND INSTALL THE UNIT 4 FIRE PROTECTION SYSTEM (FPS) ON ISOMETRICS (SV3-FPS-PLW-967, 968, 96AN, 96AR, 96AS, 96AT) |
| 1335 | SV4-CA20-S4W-CV6834 | CA20-36 Temporary Attachments FLOORS |
| 1336 | SV3-WLS-PHW-ME3865 | FABRICATION/INSTALLATION OF SMALL BORE WLS PIPING SUPPORTS FOR ISOMETRICS SV3-WLS-PLW-202, -203 |
| 1337 | SV3-WLS-P0W-ME3500 | INSTALLATION OF SMALL BORE WLS PIPING (ISOMETRICS SV3-WLS-PLW-299, 300) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1338 | SV3-WLS-P0W-ME3814 | INSTALLATION OF SMALL BORE WLS PIPING (ISOMETRICS SV3-WLS-PLW-202, -203, -205) |
| 1339 | SV4-2040-CEW-CV8874 | UNIT 4, TURBINE BUILDING, 120' ELEVATED DECK, SLEEVES - POUR #4 |
| 1340 | SV3-KQ11-KQW-KQ8908 | UNIT 3 OFF-SITE FABRICATION OF KQ11 SUMP COVER |
| 1341 | SV3-0150-ERW-EL7457 | CABLE TRAY SUPPORT FOR AUX TRANSFORMER 2C |
| 1342 | SV3-ML05-MLW-ME5930 | INSTALLATION OF CA35 PENETRATIONS |
| 1343 | SV3-PWS-PHW-ME4949 | INSTALLATION OF ANNEX PORTABLE WATER SYSTEM (PWS) PIPING SUPPORTS FOR WP (SV3-PWS-P0W-ME4948) |
| 1344 | SV3-PXS-MTW-ME2935 | ASME SECTION III - INSTALL PXS ACCUMULATOR TANK SV3-PXS-MT-01B |
| 1345 | SV4-MP1J-MPW-ME7424 | INSTALLATION OF CCS PUMPS (CCS-MP-01A-CCS-MP-01B) |
| 1346 | SV4-CA20-ERW-EL6717 | INSTALL ELECTRICAL WALL PENETRATIONS IN U4 CA20 MODULE SUB-ASSEMBLY 4 |
| 1347 | SV4-CA20-ERW-EL6716 | INSTALL ELECTRICAL WALL PENETRATIONS IN U4 CA20 MODULE SUB-ASSEMBLY 3 |
| 1348 | SV3-CA20-EGW-EL8857 | INSTALL GROUNDING TO MISCELLANEOUS ITEMS SUCH AS STAIRS, LADDERS OR GRATING FOR SV#3 MODULE CA20, 66'-6" - 117'-6" AREAS 5&6 |
| 1349 | SV4-CA20-ERW-EL6715 | INSTALL ELECTRICAL WALL PENETRATIONS IN U4 CA20 MODULE SUB-ASSEMBLY 2 |
| 1350 | SV4-KB16-KBW-ME6709 | INSTALLATION OF THE KB16 MODULE |
| 1351 | SV4-CA01-S4W-CV8687 | CA01-09 TEMPORARY ATTACHMENT PLATE IDs |
| 1352 | SV4-WLS-P0W-ME6169 | UNIT 4 - PHASE 12 - LIQUID RADWASTE PIPING, WLS S/S CORE PIPING |
| 1353 | SV3-WLS-THW-ME6212 | HYDRO TEST THE UNIT 3 LIQUID RADWASTE SYSTEM PIPING PHASE 12 |
| 1354 | SV4-WLS-THW-ME6215 | HYDRO TEST THE UNIT 4 LIQUID RADWASTE SYSTEM PIPING PHASE 12 |
| 1355 | SV4-WLS-THW-ME6214 | HYDRO TEST THE UNIT 4 LIQUID RADWASTE SYSTEM PIPING PHASE 10 |
| 1356 | SV3-WLS-THW-ME6211 | HYDRO TEST THE UNIT 3 LIQUID RADWASTE SYSTEM PIPING PHASE 10 |
| 1357 | SV4-1232-ERW-EL7206 | INSTALL CONDUIT SLEEVES FOR PENETRATIONS IN UNIT 4 AUX BUILDING FLOOR SLABS, EL 100'-0"AREA 2 RMS. 12312 & 12313 |
| 1358 | SV3-RWS-EWW-EL15129 | UNIT 3 CABLE PULL BETWEEN MANHOLES NWM013 AND NWM016 |
| 1359 | SV3-RWS-EWW-EL15128 | UNIT 3 RWS CABLE PULL BETWEEN MANHOLES NWM010 AND NWM013 |
| 1360 | SV3-RWS-EWW-EL15127 | UNIT 3 RWS CABLE PULL BETWEEN MANHOLES NWM008 AND NWM010 |
| 1361 | SV3-4000-CRW-CV8776 | UNIT 3 ANNEX REINFORCEMENT FIELD FABRICATION |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1362 | SV3-4052-CEW-CV7520 | U3 ANNEX BUILDING AREA 2 INSTALL EMBEDS ELEVATION 117'6" TO ELEVATION 135'3" |
| 1363 | SV3-4052-CRW-CV7435 | U3 ANNEX BUILDING AREA 2, INSTALL REBAR ELEVATION 117'6" TO ELEVATION 135'3" |
| 1364 | SV4-CDS-P0W-ME7119 | INSTALLATION OF CDS PIPING |
| 1365 | SV4-CA01-S4W-CV8699 | CA01-21 TEMPORARY ATTACHMENT PLATE ID'S |
| 1366 | SV4-CA01-S4W-CV8686 | A01-08 TEMPORARY ATTACHMENT PLATE ID'S |
| 1367 | SV4-CA01-S4W-CV8700 | CA01-22 TEMPORARY ATTACHMENT PLATE ID'S |
| 1368 | SV4-RWS-EWW-EL8570 | UNIT 4 RWS Cable Pull Between NWM016 and NWM020 |
| 1369 | SV3-RWS-EWW-EL15130 | UNIT 3 RWS Cable Pull Between Manholes NWM016 and NWM020 |
| 1370 | SV4-RWS-EWW-EL8568 | UNIT 4 RWS Cable Pull Between NWM010 and NWM014 |
| 1371 | SV4-RWS-EWW-EL8567 | UNIT 4 RWS CABLE PULL BETWEEN NWM007 AND NWM010 |
| 1372 | SV3-WGS-THW-ME8911 | (BLANK) |
| 1373 | SV4-RWS-EWW-EL8569 | UNIT 4 RWS Cable Pull Between NWM014 and NWM016 |
| 1374 | SV0-PWS-P0W-ME8893 | FABRICATE AND INSTALL THE POTABLE WATER SYSTEM (PWS) TO BLDG 314 |
| 1375 | SV4-CA02-MHW-860100 | SV4-CA02 lift Frame & Bracing Installations |
| 1376 | SV4-CA02-S4W-860101 | CA02-01 Temporary Attachment installation/Removal |
| 1377 | SV4-CA02-S4W-860102 | CA02-02 Temporary Attachment Instalation/Removal |
| 1378 | SV4-CA02-S4W-860103 | CA02-03 Temporary Attachment Installation/Removal |
| 1379 | SV4-CA02-S4W-860105 | CA02-05 Temporary Attachment Installation/Removal |
| 1380 | SV3-SFS-P0W-860111 | FABRICATION/INSTALLATION OF PIPING FOR ISOMETRIC SV3-SFS-PLW-15R |
| 1381 | SV3-RNS-P0W-860114 | FABRICATION/INSTALLATION OF PIPING FOR ISOMETRIC SV3-RNS-PLW-174 |
| 1382 | SV3-MS09-MEW-ME5492 | INSTALLATION OF THE EFFLUENT SAMPLE ANALYSIS RACK (DTS-MS-06) |
| 1383 | SV3-MP1Q-MEW-ME3692 | INSTALLATION OF BDS STEAM GENERATOR BLOWDOWN EDI RECIRCULATION & DRAIN PUMP (BDS-MP-01) |
| 1384 | SV3-MSS-P0W-ME4657 | INSTALLATION OF MSS PIPING |
| 1385 | SV3-MSS-PHW-ME4656 | INSTALLATION OF PIPE SUPPORTS FOR PIPING PACKAGE SV3-MSS-P0W-ME4655 |
| 1386 | SV4-CDS-PHW-ME7120 | INSTALLATION OF PIPE SUPPORTS FOR PIPING PACKAGE SV4-CDS-P0W-ME7119 |
| 1387 | SV3-RNS-P0W-ME3083 | INSTALLATION OF RNS SMALL BORE PIPING (INCLUDES ISOMETRIC SV3-RNS-PLW-216) |
| 1388 | SV3-2053-SHW-EL8557 | Electrical Cable Tray Support Installation in the Turbine Building, Elevation 141’-3”, Area 3, Room 20501 (Switchgear Room #2) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1389 | SV3-2053-SHW-EL8558 | Electrical Cable Tray Support Installation in the Turbine Building, Elevation 141’-3”, Area 3, Room 20503 (Control Cabinet Room) Trapeze Roads |
| 1390 | SV3-2052-SHW-EL8559 | Electrical Cable Tray Support Installation in the Turbine Building, Elevation 141’-3”, Area 2, Room 20500 |
| 1391 | SV3-2052-SHW-EL8561 | Electrical Cable Tray Support Installation in the Turbine Building, Elevation 141’-3”, Area 2, Room 20502 (Switchgear Room #1) |
| 1392 | SV4-ML05-MLW-ME8413 | Install SV4 CA05 / CA02 Penetration SV4-11305-ML-P01 |
| 1393 | SV4-VCS-P0W-ME8415 | Fabrication/Installation of Piping for Isometric SV4-VCS-PLW-020 |
| 1394 | SV3-1208-C0W-850006 | UNIT 3 AUXILIARY EL 117'-6" FT. - CYLINDRICAL WALL - CIVIL - RC06 |
| 1395 | SV4-CA01-S4W-CV8702 | CA01-24 TEMPORARY ATTACHMENT PLATE ID |
| 1396 | SV3-MSS-PHW-ME4650 | INSTALLATION OF PIPE SUPPORTS FOR PIPING PACKAGE SV3-MSS-P0W-ME4649 |
| 1397 | SV3-MSS-P0W-ME4669 | INSATLLATION OF MAIN STEAM PIPING |
| 1398 | SV3-MSS-P0W-ME4667 | INSTALLATION OF MAIN STEAM PIPING |
| 1399 | SV3-SFS-P0W-ME4356 | INSATLLATION F LARGE BORE SFS PIPING ISOMETRICS SV3-SFSPLW-541, 551, 567, 568, 56A, 56D |
| 1400 | SV4-WRS-THW-ME8998 | TESTING OF CA20 LEAK CHASE |
| 1401 | SV4-CA01-S4W-CV8683 | CA01-05 TEMPORARY ATTACHMENT PLATE ID |
| 1402 | SV4-CA01-S5W-CV6390 | CA01-09 UNSAT IRs/ N&Ds/E&DCRs/LOOSE PARTS - STRUCTURAL |
| 1403 | SV4-2020-MEW-ME1601 | UNIT 4 CONDENSER C FLASHBOX INSTALLATION |
| 1404 | SV0-CE01-CEW-CV9005 | TENSILE TESTING OF COUPLER WELDS ON CARBON STEEL EMBED PLATEDS FROM CIVES & JOSEPH OAT |
| 1405 | SV3-PXS-PHW-ME4503 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-02M |
| 1406 | SV4-2040-SSW-CV1830 | TURBINE BUILDING STRUCTURAL STEEL ERECTION SEQUENCE 11 |
| 1407 | SV4-2050-SSW-CV1823 | CA81 TEMPORARY FRAMING/PERMANENT FORMS (TB05) |
| 1408 | SV4-CWS-PHW-ME7144 | INSTALLATION AND FABRICATION OF CIRCULATING WATER SYSTEM (CWS) PIPING SUPPORTS |
| 1409 | SV3-0150-ERW-EL7458 | CABLE TRAY SUPPORT FOR AUX TRANSFORMER 2B |
| 1410 | SV3-4032-SHW-EL4039 | INSTALL CABLE TRAY SUPPORTS ANNEX BLDG AREA 2, ROOM 40326 NORTH WEST |
| 1411 | SV3-1124-SSW-CV6257 | SPL20 INSTALLATION |
| 1412 | SV4-CA01-S4W-CV8684 | CA01-16 TEMPORARY ATTACHMENT PLATE ID |
| 1413 | SV4-CWS-PLW-ME0975 | INSTALLATION OF PCCP PIPING FOR CWS UNIT #4 PHASE 3 SUPPLY LINE |
| 1414 | SV4-TCS-PHW-ME5478 | INSTALLATION AND FABRICATION OF TURBINE BUILDING CLOSED COOLING WATER SYSTEM (TCS) PIPING SUPPORT |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1415 | SV4-CA01-S4W-CV8685 | CA01-07 TEMPORARY ATTACHMENT PLATE ID |
| 1416 | SV3-RNS-P0W-ME3511 | FABRICATION/INSTALLATION OF PIPING FOR ISO SV3-RNS-PLW-179 |
| 1417 | SV3-RNS-P0W-ME3495 | FABRICATION/INSTALLATION OF PIPING FOR ISO SV3-RNS-PLW-096, SV3-RNS-PLW-097 |
| 1418 | SV3-MSS-P0W-ME2157 | FABRICATION AND INSTALLATION OF MAIN STEAM SYSTEM (MSS) PIPING |
| 1419 | SV4-1220-ERW-EL6806 | CONDUIT SLEEVES, UNIT 4 AUXILIARY BUILDINTG FLOOR SLAB, ELEVATION 82'-6", AREA 1 & 2 |
| 1420 | SV4-CA01-S4W-CV8704 | CA01_27 TEMPORARY ATTACHMENT PLATE ID |
| 1421 | SV3-2033-SHW-EL9017 | Electrical Cable Tray Support Installation in the Turbine Building, Elevation 100', Area 3 ROOM 20300 TRAPEZ RODS |
| 1422 | SV3-2033-SHW-EL9018 | Electrical Cable Tray Support Installation in the Turbine Building, Elevation 100', AREA 3, ROOM 20303 & 20304 TRAPEZE RODS |
| 1423 | SV4-1120-CCW-CV4120 | UNIT 4 CONTAINMENT PLACEMENT, CURING AND REPAIR OF CONCRETE EL 76'-6" TO EL 80'-0 & 80'-6" |
| 1424 | SV3-MS09-MEW-ME4791 | INSTALLATION OF CARTRIDGE FILTER SKID (DTS-MS-01) |
| 1425 | SV4-HDS-PHW-ME5472 | INSTALLATION AND FABRICATION OF HEATER DRAIN SYSTEM(HDS) PIPE SUPPORT |
| 1426 | SV4-HDS-PHW-ME5474 | INSTALLATION AND FABRICATION OF HEATER DRAIN SYSTEM(HDS) PIPE SUPPORT |
| 1427 | SV4-KQ11-KQW-860179 | UNIT 4 OFF-SITE FABRICATION OF KQ11 SUMP COVER |
| 1428 | SV4-1208-SCW-CV6995 | COURSE 2 UNIT 4 SHIELD BUILDING |
| 1429 | SV4-HDS-PHW-ME5476 | INSTALLATION AND FABRICATION OF HEATER DRAIN SYSTEM(HDS) PIPE SUPPORT |
| 1430 | SV4-FPS-THW-ME7381 | HYDRO TEST UNIT 4 FIRE PROTECTION PIPING (FPS) PIPING ON ISOMETRICS (SV4-FPS-PLW-967, 968, 96AN, 96AR, 96AS, 96AT) |
| 1431 | SV4-1220-EGW-EL6288 | INSTALL GROUND CABLES AND WALL PLATES FOR INTERIOR WALLS FROM ELEV. 82'-6" TO 100'-0" TO INCLUDE PIGTAILS FOR EXTENSIONS TO ELEV 117'-6" AREA 1 & 2 |
| 1432 | SV3-WLS-PHW-ME0823 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING WLS-PLW-370 |
| 1433 | SV3-RNS-P0W-ME3513 | INSTALLATION OF RNS LARGE BORE PIPING (INCLUDES ISOMETRIC SV3-RNS-PLW-173) |
| 1434 | SV4-CA03-S4W-860180 | CA03 Wall Submodule Assembly (07, 08, 09, 10, 11) |
| 1435 | SV4-CA03-S4W-860193 | CA03 Temporary Bracing for Lift into NI |
| 1436 | SV4-2050-EGW-860198 | INSTALLATION OF EMBEDDED GROUNDING IN TURBINE #4 CONCRETE SLABS AT ELEV 135'-3" AND 141'-3" |
| 1437 | SV3-ML05-MLW-860199 | Fabricate Annex Building Wall 09 Pipe Penetrations |
| 1438 | SV3-WWS-PHW-ME6698 | INSTALLATION AND FABRICATON OF WASTE WATER SYSTEM PIPE SUPPORTS FOR 120" ELEVATION |
| 1439 | SV3-SFS-P0W-860200 | "Fabrication/Installation of Piping for Isometric SV3-SFS-PLW-35T |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1440 | SV3-IDS-DBW-860172 | INSTALL IDS DIVISION A BATTERY RACKS IN ROOM 12101 AREA 2 66'-6 |
| 1441 | SV3-IDS-DBW-860173 | INSTALL IDS DIVISION C BATTERY RACKS IN ROOM 12102 AREA 2 66'-6 |
| 1442 | SV3-IDS-DBW-860174 | INSTALL IDS DIVISION S BATTERY RACKS IN ROOM 12103 AREA 2 66'-6 |
| 1443 | SV3-IDS-DBW-860175 | INSTALL IDS DIVISION B BATTERY RACKS IN ROOM 12104 AREA 1 66'-6 |
| 1444 | SV3-IDS-DBW-860176 | INSTALL IDS DIVISION D BATTERY RACKS IN ROOM 12105 AREA 1 66'-6 |
| 1445 | SV4-CA02-S4W-860149 | CA02-01 Thru -04 Upend / Submodule Installation |
| 1446 | SV4-CA02-S5W-860150 | CA02-01 Unsat IRs and N&Ds - Studs |
| 1447 | SV3-WWS-PHW-ME6702 | FABRICATION AND INSTALLATION OF WWS SUPPORTS |
| 1448 | SV3-WWS-PHW-ME6700 | INSTALLATION AND FABRICATION OF WASTE WATER SYSTEM (WWS) SUPPORTS |
| 1449 | SV4-CA02-S4W-860160 | CA02-03 OLPs and Welded Attachments |
| 1450 | SV3-RNS-P0W-ME7623 | FABRICATION/INSTALLATION OF PIPING FOR ISO SV3-RNS-PLW-17C |
| 1451 | SV3-MSS-PHW-ME4642 | INSTALLATION AND FABRICATION OF MAIN STEAM SYSTEM (MSS) PIPING SUPPORT |
| 1452 | SV3-CCS-P0W-ME5977 | INSTALLATION OF LARGE BORE CCS PIPING INCLUDING ISOMETRICS SV3-CCS-PLW-517 |
| 1453 | SV3-RNS-P0W-ME7619 | FABRICATION/INSTALLATION OF PIPING FOR ISO SV3-RNS-PLW-172 |
| 1454 | SV3-RNS-P0W-ME7621 | FABRICATION/INSTALLATION OF PIPING FOR ISO SV3-RNS-PLW-176 |
| 1455 | SV3-RNS-P0W-ME7626 | FABRICATION/INSTALLATION OF PIPING FOR ISO SV3-RNS-PLW-17K |
| 1456 | SV3-RNS-P0W-ME7628 | FABRICATION/INSTALLATION OF PIPING FOR ISO SV3-RNS-PLW-17U |
| 1457 | SV3-1230-C0W-855000 | 100'-0" ELEV WALLS, CL I, WALL 72 |
| 1458 | SV3-1230-C0W-855001 | 100'-0" ELEV WALLS, CL I, WALL 73 |
| 1459 | SV3-WLS-P0W-ME3502 | INSTALLATION OF LARGE BORE WLS PIPING (INCLUDES SV3-WLS-PLW-333, SV3-WLS-PLW-33P) |
| 1460 | SV3-SFS-P0W-ME6117 | (BLANK) |
| 1461 | SV3-1230-C0W-850015 | 100'-0" ELEV WALLS, CL 5, WALL 94 |
| 1462 | SV3-1230-C0W-850016 | 100' Elev Walls, CL 4 WALL 96 |
| 1463 | SV3-1230-C0W-850017 | 100'-0" ELEV WALLS, CL J-2, WALL 97 |
| 1464 | SV3-1230-C0W-855002 | 100'-0" ELEV WALLS, CL 1, WALL 75 |
| 1465 | SV3-WLS-P0W-ME6217 | UNIT 3 WLS PIPING IN PHASE 1 & 2 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1466 | SV3-WLS-P0W-ME6167 | UNIT 3 PHASE 12 DOUBLE WALL PIPING INSTALLATION WLS |
| 1467 | SV4-WLS-P0W-ME6218 | UNIT 4 WLS PIPING IN PHASE 1 & 2 |
| 1468 | SV3-ME04-MEW-ME5688 | INSTALL MOISTURE SEPARATOR REHEATER A |
| 1469 | SV3-ME04-MEW-ME5720 | INSTALL MOISTURE SEPARATOR REHEATER B |
| 1470 | SV4-CA20-ERW-EL6718 | INSTALL ELECTRICAL FLOOR PENETRATIONS IN U4 CA20 MODULE |
| 1471 | SV4-1233-ERW-EL7207 | INSTALL CONDUIT SLEEVES FOR PENETRATIONS IN UNIT 4 AUX BUILDING FLOOR SLABS, EL 100'-0"AREA 3 RM. 12321 & AREA 4 RM. 12351 & 12253 |
| 1472 | SV4-1235-ERW-EL7208 | INSTALL CONDUIT SLEEVES FOR PENETRATIONS IN UNIT 4 AUX BUILDING FLOOR SLABS, EL 100'-0"AREA 5 RM. 12361 & AREA 6 RM. 12372 |
| 1473 | SV3-RNS-PHW-ME8839 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISO SV3-RNS-PLW-216 |
| 1474 | SV4-2040-CEW-CV8873 | UNIT 4, TURBINE BUILDING, 120' ELEVATION, MECH/ ELEV CLEEVE, POUR #3 |
| 1475 | SV4-WLS-MTW-ME1807 | WLS EFFLUENT HOLDUP TANK B INSTALLATION |
| 1476 | SV4-WLS-MTW-ME1806 | WLS EFFLUENT HOLDUP TANK A INSTALLATION |
| 1477 | SV3-RNS-P0W-ME3081 | RNS PUMP A SEAL COOLER DRAIN PIPING ROOM 12162 |
| 1478 | SV3-RNS-P0W-ME3080 | RNS PUMP A SEAL COOLER VENT PIPING ROOM 12162 |
| 1479 | SV3-RNS-P0W-ME3082 | RNS PUMP B SEAL COOLER VENT PIPING ROOM 12163 |
| 1480 | SV4-2040-CEW-CV8871 | UNIT 4, TURBINE BUILDING, 120' ELEVATION, MECH / ELEV SLEEVE, POUR #1 |
| 1481 | SV4-2040-CEW-CV8872 | UNIT 4, TURBINE BUILDING, 120' ELEVATION, MECH / ELEV SLEEVE, POUR #2 |
| 1482 | SV3-DOS-CCW-CV8398 | CONCRETE FOR THE UNIT 3 DOS TANK A WALLS PLACEMENTS 1-3 |
| 1483 | SV3-RNS-PHW-ME8838 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISO SV3-RNS-PLW-214 |
| 1484 | SV3-2054-SHW-EL8953 | Electrical Cable Tray Supplemental Steel Installation in the Turbine Building, Below Elevation 169’-0” |
| 1485 | SV3-2055-SHW-EL8955 | Electrical Cable Tray Supplemental Steel Installation in the Turbine Building, Below Elevation 169’-0”, Area 5 From COLUMNS 13.1 TO 16 & I.2 TO K.1 |
| 1486 | SV3-2058-SHW-EL8956 | Electrical Cable Tray Supplemental Steel Installation in the Turbine Building, Below Elevation 169’-0”, AREA 8 FROM COLUMNS 13.05 TO 16, & I.2 TO H.05 |
| 1487 | SV3-1160-SSW-CV3062 | C8 CIRCULAR TRUNK SPL31, 32, 33 |
| 1488 | SV4-CVS-P0W-ME8913 | Installation of CVS Piping (Includes Isometric SV4-CVS-PLW-65D, 65E) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1489 | SV4-CVS-P0W-ME8914 | FABRICATION/INSTALLATION OF CVS PIPING (INCLUDING ISOMETRIC DRAWINGS SV4-CVS-PLW-563, -564, -566, -567 AND -568) |
| 1490 | SV4-PWS-PHW-ME8853 | FABRICATION/INSTALLATION OF PWS PIPING SUPPORST (ISOMETRIC DRAWING: SV4-PWS-PLW-923) |
| 1491 | SV4-PWS-PHW-ME8854 | FABRICATION/INSTALLATION OF SMALL BORE PWS PIPING SUPPORTS FOR ISOMETRIC DRAWING SV4-PWS-PLW-921 AND -924 |
| 1492 | SV3-PXS-PHW-ME8735 | Fabrication/Installation of Pipe Supports for Isometric SV3-PXS-PLW-185 |
| 1493 | SV3-PXS-PHW-ME8736 | Fabrication/Installation of Pipe Supports for Isometric SV3-PXS-PLW-187 & 188 |
| 1494 | SV3-PXS-PHW-ME8737 | Fabrication/Installation of Pipe Supports for Isometric SV3-PXS-PLW-01E |
| 1495 | SV3-PXS-PHW-ME8738 | Fabrication/Installation of Pipe Supports for Isometric SV3-PXS-PLW-470 |
| 1496 | SV3-PXS-PHW-ME8740 | Fabrication/Installation of Pipe Supports for Isometric Drawing SV3-PXS-PLW-510 |
| 1497 | SV3-PXS-PHW-ME8741 | Fabrication/Installation of Pipe Supports for Isometric SV3-PXS-PLW-512 |
| 1498 | SV3-PXS-PHW-ME8742 | Fabrication/Installation of Pipe Supports for Isometric SV3-PXS-PLW-750 |
| 1499 | SV3-PXS-PHW-ME8743 | Fabrication/Installation of Pipe Supports for Isometric SV3-PXS-PLW-285 |
| 1500 | SV3-PXS-PHW-ME8744 | Fabrication/Installation of Pipe Supports for Isometric SV3-PXS-PLW-286 |
| 1501 | SV3-PXS-PHW-ME8745 | Fabrication/Installation of Pipe Supports for Isometric SV3-PXS-PLW-731 |
| 1502 | SV3-PXS-PHW-ME8746 | Fabrication/Installation of Pipe Supports for Isometric SV3-PXS-PLW-761 |
| 1503 | SV3-PXS-PHW-ME8747 | Fabrication/Installation of Pipe Supports for Isometric Drawing SV3-PXS-PLW-511 |
| 1504 | SV3-2057-SHW-EL8935 | Electrical Cable Tray Supplemental Steel Installation in the Turbine Building, Below Elevation 169’-0” |
| 1505 | SV3-1208-SCW-CV8901 | Unit 3 Temporary Attachments |
| 1506 | SV4-2050-CEW-CV8877 | Unit 4, Turbine Building 141'-3" Elev - Piping / Elec Sleeves - Pour #1 |
| 1507 | SV4-2050-CEW-CV8878 | Unit 4, Turbine Building 140' Elev - Electrical Sleeves - Pour #2 |
| 1508 | SV4-2050-CEW-CV8879 | Unit 4, Turbine Building 140' Elev - Mech/Electrical Pour #3 |
| 1509 | SV4-2050-CEW-CV8880 | Unit 4, Turbine Building 140' Elev - Mech / Elec Sleeves - Pour #4 |
| 1510 | SV4-2050-CEW-CV8881 | Unit 4, Turbine Building 141'-3" Elev - Piping / Elec Sleeves - Pour #5 |
| 1511 | SV4-2050-CEW-CV8882 | Unit 4, Turbine Building 141'-3" Elev - Piping / Elec Sleeves - Pour #6 |
| 1512 | SV4-ML05-MLW-ME8410 | INSTALL SV4 CA05 PENETRATION SV4-11209-ML-P02 |
| 1513 | SV3-ME03-MEW-ME8407 | INSTALLATION OF DEAERATOR SV3-CDS-ME-05 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1514 | SV3-DWS-PHW-ME6352 | INSTALLTION OF ANNEX BLDG DWS PIPE SUPPORTS (ISOMETRICS SV3-DWS-PLW-139 & -143) |
| 1515 | SV3-2056-SHW-EL8934 | Electrical Cable Tray Supplemental Steel Installation in the Turbine Building, Below Elevation 169'-0" AREA 6 FROM COLUMNS 16 TO 18 & 1.2 TO K.5 |
| 1516 | SV3-2059-SHW-EL8936 | Electrical Cable Tray Supplemental Steel Installation in the Turbine Building, Below Elevation 169'-0" Area 9 from Columns 17 to 18 & H.05 to 1.2 |
| 1517 | SV3-4051-CRW-CV8902 | Unit 3 Annex Area 1 Reinforcement to Elevation 135'-03" |
| 1518 | SV3-4051-CCW-CV8903 | Wall 09 Embeds, Formwork, and Concrete to Elevation 135'-03" |
| 1519 | SV3-4051-CCW-CV8904 | Wall 10 Area 1 Embeds, Formwork, and Concrete to Elevation 135'-03" |
| 1520 | SV3-4051-CCW-CV8905 | Wall 14 Area 1 Embeds, Formwork, and Concrete to Elevation 135'-03" |
| 1521 | SV3-4051-CCW-CV8906 | Wall 15 Embeds, Formwork, and Concrete to Elevation 135'-03" |
| 1522 | SV4-CDS-PHW-ME7118 | INSTALLATION OF PIPE SUPPORTS FOR WP ME7117 |
| 1523 | SV4-CDS-PHW-ME7114 | INSTALLATION OF CDS PIPE SUPPORTS FOR WP ME7113 |
| 1524 | SV4-CA01-S4W-CV8701 | CA01-23 TEMPORARY ATTACHMENT PLATE ID |
| 1525 | SV3-TCS-PHW-ME8466 | INSTALLATION OF TURBINE BUILDING CLOSED COOLING WATER SYSTEM (TCS) PIPE SUPPORTS |
| 1526 | SV3-TCS-P0W-ME8467 | Installation of¿Turbine Building Closed Cooling Water¿System (TCS) Piping |
| 1527 | SV3-TCS-PHW-ME8468 | Installation of Turbine Building Closed Cooling Water System (TCS) Pipe Supports |
| 1528 | SV3-VYS-P0W-ME8529 | Installation of Hot Water Heating System (VYS) Piping |
| 1529 | SV3-VYS-PHW-ME8530 | Installation of Hot Water Heating System (VYS) Pipe Supports |
| 1530 | SV3-VYS-P0W-ME8545 | Installation of Hot Water Heating System (VYS) Piping |
| 1531 | SV3-VYS-PHW-ME8546 | Installation of VYS Pipe Supports |
| 1532 | SV4-1220-ERW-EL5418 | Install electrical penetrations in Aux Building Shield Wall from 82'-6" to 100'-0"" |
| 1533 | SV3-CB32-CBW-850000 | CB32 MODULE INSTALLATION |
| 1534 | SV4-4030-CCW-CV8751 | UNIT 4 ANNEX MUD MAT AREAS 1-3 |
| 1535 | SV4-MP50-MPW-ME5925 | INSTALLATION OF THE WWS SUMP PUMPS (WWS-MP-01A/B, WWS-MP-07A/B, WWS MP-08A/B) |
| 1536 | SV4-CB22-CBW-850000 | CB-22 & 23 Module Installation |
| 1537 | SV3-CA03-CAW-850000 | CA03 Module Installation |
| 1538 | SV3-2060-SSW-CV8964 | Turbine Building Sequence 12 Grating and Decking |
| 1539 | SV3-2050-SSW-CV8966 | TURBINE BUILDING SEQUENCE 18 ROOMS 20501, 20502 & 20503 |
| 1540 | SV3-4053-CRW-CV8777 | Unit 3 Annex Area 3 Reinforcement to Elevation 135'-03" |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1541 | SV3-4053-CCW-CV8778 | Wall 10 & Wall 132 Embeds, Formwork, and Concrete to Elevation 135'-03" |
| 1542 | SV3-4053-CCW-CV8779 | Wall 02 & Wall 31 Embeds, Formwork, and Concrete to Elevation 135'-03" |
| 1543 | SV3-4053-CCW-CV8780 | UNIT 3 ANNEX AREA 3 WALL 16 & WALL 26 TO ELEVATION 135'-03" |
| 1544 | SV3-4053-CCW-CV8781 | Wall 01 & Wall 19 Embeds, Formwork, and Concrete to Elevation 135'-03" |
| 1545 | SV3-4053-CCW-CV8782 | Embeds, Formwork, and Concrete for Elevated Slabs to Elevation 135'-03" |
| 1546 | SV3-1220-EGW-EL8961 | Install Grounding From Wall Plates to Floor Plates & Pigtails, Elevation 82'-6" |
| 1547 | SV4-1210-EGW-EL8970 | Misc. grounding 66'-6" Unit 4 Aux |
| 1548 | SV3-1151-ERW-EL8972 | Fabrication and Installation of Conduit Supports for Area 1 & 2 on Ring 2 of the Containment Vessel at EL. 131'-9" to 170'-0" |
| 1549 | SV3-1154-ERW-EL8981 | Fabrication and Installation of Cable Tray Supports for Area 4 on Ring 2 of the Containment Vessel at EL. 131'-9" to 170'-0". |
| 1550 | SV3-1154-ERW-EL8982 | Fabrication and Installation of Cable Tray Supports for Area 4 on Ring 2 of the Containment Vessel at EL. 131'-9" to 170'-0". |
| 1551 | SV3-4041-SAW-EL8772 | INSTALL SUPPLEMENTAL STEEL FOR ELECTRICAL HANGERS COL. LN. H10.05/H11.09 TO F10.05/H11.09 |
| 1552 | SV3-4041-SAW-EL8774 | INSTALL SUPPLEMENTAL STEEL FOR ELECTRICAL HANGERS COL. LN. I.1-11.09/I.1-31 TO G-11.09/G13 |
| 1553 | SV3-4041-SAW-EL8775 | INSTALL SUPPLEMENTAL STEEL FOR ELECTRICAL HANGERS COL. LN. G-11.09/G13 TO E-11.09/E13 |
| 1554 | SV3-1153-ERW-EL8973 | Fabrication and Installation of Conduit Supports for Area 3 on Ring 2 of the Containment Vessel at EL. 131'-9" to 170'-0" |
| 1555 | SV3-1152-ERW-EL8975 | Fabrication and Installation of Cable Tray Supports for Area 2 on Ring 2 of the Containment Vessel at EL. 131'-9" to 170'-0".4 |
| 1556 | SV3-1153-ERW-EL8977 | Fabrication and Installation of Cable Tray Supports for Area 3 on Ring 2 of the Containment Vessel at EL. 131'-9" to 170'-0". |
| 1557 | SV3-1153-ERW-EL8978 | Fabrication and Installation of Cable Tray Supports for Area 3 on Ring 2 of the Containment Vessel at EL. 131'-9" to 170'-0". |
| 1558 | SV3-1153-ERW-EL8979 | Fabrication and Installation of Cable Tray Supports for Area 3 on Ring 2 of the Containment Vessel at EL. 131'-9" to 170'-0". |
| 1559 | SV4-WWS-P0W-ME8940 | INSTALLATION AND FABRICATION OF WASTE WATER SYSTEM |
| 1560 | SV4-WWS-PHW-ME8941 | Installation of WWS pipe supports (120' slab) for slabs 4,5,& 6 |
| 1561 | SV4-ME01-PLW-ME8942 | INSTALLATION OF AIR VENT PIPING FOR CONDENSER A |
| 1562 | SV4-ME01-PLW-ME8943 | INSTALLATION OF AIR VENT PIPING FOR CONDENSER B |
| 1563 | SV0-PWS-MTW-ME8946 | Install anchor straps on PWS Chemical Feed Tanks SV0-PWS-MT-501A & 501B |
| 1564 | SV4-ME01-PLW-ME8947 | (BLANK) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1565 | SV3-RNS-P0W-ME8971 | FABRICATION/INSTALLATION OF PIPING FOR ISO SV3-RNS-PLW-097 |
| 1566 | SV3-WLS-P0W-ME8993 | INSTALLATION OF SMALL BORE WLS PIPING ISOMETRIC SV3-WLS-PLW-103 |
| 1567 | SV0-SDS-THW-ME8843 | Pressure Test of the Unit 3 & 4 Sanitary Sewer System (SDS) in the Yard Area |
| 1568 | SV3-SFS-PHW-ME8761 | Fabrication/Installation of Pipe Supports for Isometric Drawing SV3-SFS-PLW-789 |
| 1569 | SV3-RNS-PHW-ME8762 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-RNS-PLW-181 |
| 1570 | SV3-RNS-PHW-ME8763 | Fabrication/Installation of Pipe Supports for Isometric SV3-RNS-PLW-182 |
| 1571 | SV3-RNS-PHW-ME8764 | Fabrication/Installation of Pipe Supports for Isometric SV3-RNS-PLW-183 |
| 1572 | SV3-RNS-PHW-ME8765 | Fabrication/Installation of Pipe Supports for Isometric SV3-RNS-PLW-184 |
| 1573 | SV3-RNS-PHW-ME8766 | Fabrication/Installation of Pipe Supports for Isometric SV3-RNS-PLW-186 |
| 1574 | SV3-RNS-PHW-ME8767 | Fabrication/Installation of Pipe Supports for Isometric SV3-RNS-PLW-18C |
| 1575 | SV3-RNS-PHW-ME8768 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-RNS-PLW-370 |
| 1576 | SV3-RNS-PHW-ME8769 | Fabrication/Installation of Pipe Supports for Isometric SV3-RNS-PLW-390 |
| 1577 | SV3-ML05-MLW-ME8734 | Room 12259 92'6" Floor Penetrations |
| 1578 | SV3-CA20-SHW-EL5052 | FIELD ROUTED TYPICAL CONDUIT SUPPORT C31 FOR CA20 MODULE, ELEV. 82FT-6IN TO 100FT-0IN |
| 1579 | SV3-CA20-SHW-EL5051 | FIELD ROUTED TYPICAL CONDUIT SUPPORT C15 FOR CA20 MODULE, ELEV. 82'-6IN TO 100'-0" |
| 1580 | SV3-CA20-SHW-EL5050 | FIELD ROUTED TYPICAL CONDUIT SUPPORT C14 FOR CA20 MODULE, ELEV. 82'-6" TO 100'-0" |
| 1581 | SV3-CA20-SHW-EL5049 | FIELD ROUTED TYPICAL CONDUIT SUPPORT C13 FOR CA20 MODULE, ELEV. 82'-6" TO 100'-0" |
| 1582 | SV3-CA20-SHW-EL5048 | FIELD ROUTED TYPICAL CONDUIT SUPPORT C31 FOR CA20 MODULE , ELEV. 66'-6" TO 135'-0" |
| 1583 | SV3-CA20-SHW-EL5047 | FIELD ROUTED TYPICAL CONDUIT SUPPORT C15 FOR CA20 MODULE, EVEL. 66'-6" TO 135'-0" |
| 1584 | SV3-CA20-SHW-EL5046 | FIELD ROUTED TYPICAL CONDUIT SUPPORT C14 FRO CA20 MODULE, ELEV. 66'-6" TO 135'-0" |
| 1585 | SV0-REFDOC-BOP-CV8957 | Foreman's Reference Guide |
| 1586 | SV3-1231-C0W-855000 | 100' ELEV., FLOOR SLAB AREA 1 (SP-16) |
| 1587 | SV3-ME2E-MEW-ME5687 | INSTALLATION OF FEEDWATER HEATERS (CDS-ME-04A/B) |
| 1588 | SV3-ME2D-MEW-ME5899 | INSTALLATION OF FEEDWATER HEATERS (CDS-ME03A/B) |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1589 | SV3-WLS-THW-ME3151 | NON ASME WLS HYDROSTATIC TESTING |
| 1590 | SV3-MS09-MEW-ME5493 | INSTALLATION OF RO CLEAN-IN-PLACE SKID (DTS-MS-08) |
| 1591 | SV4-CA01-S4W-CV8712 | CA01-35 TEMPORARY ATTACHMENT PLATE ID |
| 1592 | SV4-CA05-S5W-CV6020 | CA05-01 UNSAT IRS & N&DS - STUDS |
| 1593 | SV3-ME2F-MEW-ME5689 | INSTALLATION OF FEEDWATER HEATERS (FWS-ME-06A & 06B) ON ELEVATION 170' |
| 1594 | SV3-ME2G-MEW-ME5686 | INSTALL FEEDWATER HEATERS SV3-FWS-ME-07A AND 07B IN THE TURBINE BUILDING |
| 1595 | SV4-ME01-PLW-ME8944 | INSTALLATION OF AIR VENT PIPING FOR CONDENSER C |
| 1596 | SV3-VWS-PLW-ME3016 | INSTALLATION OF SMALL BORE VWS PIPING (INCLUDES ISOMETRICS SV3-VWS-PLW-290) |
| 1597 | SV3-VWS-PLW-ME3018 | INSTALLATION OF SMALL BORE VWS PIPING (INCLUDES ISOMETRICS SV3-VWS-PLW-690) |
| 1598 | SV4-CA01-S4W-CV8716 | CA01-39 TEMPORARY ATTACHMENT PLATE ID |
| 1599 | SV4-CA01-S4W-CV8718 | CA01-41 TEMPORARY ATTACHMENT PLATE ID |
| 1600 | SV4-MP04-MEW-ME7108 | INSTALLATION OF THE SERVICE WATER SYSTEM PUMPS (MP01A/01B) |
| 1601 | SV3-SFS-P0W-ME6118 | AUXILLARY BUILDING ROOM 12167/12268 FROM FTC TO SFS PUMPS FOR ISO SV3-SFS-PLW-35P |
| 1602 | SV3-PXS-PHW-ME3357 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-01A |
| 1603 | SV3-PXS-PHW-ME3791 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-02Z |
| 1604 | SV3-MSS-PHW-ME4670 | MSS PIPE SUPPORTS FOR PIPE PACKAGE SV3-MSS-P0W-ME4669 |
| 1605 | SV4-2040-SSW-CV3977 | UNIT 4 TURBINE BUILDING SEQUENCE 11 HANDRAIL AND STAIRS |
| 1606 | SV3-CA20-ERW-EL7473 | MODULE CA20 UNIT 3, EL. 66'-6" TO 92'-6", INSTALL DESIGNED CONDUIT AND SUPPORTS |
| 1607 | SV3-1233-C0W-850000 | 100'-0" Elev. Floor Slabs, Area 3 (SP-19) |
| 1608 | SV3-1234-C0W-850000 | 100'-0" Elev. Floor Slabs, Area 4 (SP-21) |
| 1609 | SV3-1234-C0W-850001 | 100'-0" ELEV, FLOOR SLAB, AREA 4(SP-22) |
| 1610 | SV4-1233-C0W-850000 | 100'-0" ELEV, FLOOR SLAB, AREA 3 (SP-19) |
| 1611 | SV4-1233-C0W-850002 | 100'-0" ELEV, FLOOR SLAB, AREA 3 (SP-20) |
| 1612 | SV4-1234-C0W-850003 | 107'-2" Elev. Floor Slabs, Area 4 (SP-25) |
| 1613 | SV4-1236-C0W-850000 | 100'-0" Elev. Floor Slabs, Area 6 (SP-30) |
| 1614 | SV3-CWS-PLW-ME0974 | Installation of PCCP Piping for CWS Unit 3 Phase 3 Return Line |
| 1615 | SV4-CWS-PLW-ME0976 | Installation of PCCP Piping for CWS Unit #4 Phase 3 Return Line |
| 1616 | SV3-HDS-PHW-ME3753 | INSTALLATION AND FABRIATION OF HEATER DRAIN SYSTEM(HDS) PIPING SUPPORTS |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1617 | SV3-MSS-P0W-ME4683 | INSTALLATION AND FABRICATION OF MAIN STEAM SYSTEM(MSS) PIPING |
| 1618 | SV3-CA20-ERW-EL5042 | INSTALL SCHEDULED FIELD ROUTED CONDUIT IN "RNS PUMP ROOM B" (12163) |
| 1619 | SV3-VWS-PLW-ME3015 | INSTALLATION OF SMALL BORE VWS PIPING (INCLUDES ISOMETRICS SV3-VWS-PLW-250) |
| 1620 | SV3-CA20-ERW-EL7757 | Module CA20 Unit 3, Sub-Assembly IV El. 66'-6" to 92'-6", Install Designed Cable Trays and Supports |
| 1621 | SV4-1210-EGW-860210 | INSTALL GROUNDING FOR MISCELLANEOUS ITEMS, MODULES, STAIRS, LADDERS & TANKS UNIT 4 AUXILIARY BUILDING ELEVATION 66'6" AREA 4, 5 &6 |
| 1622 | SV3-SDS-ERW-EL0316 | Install Electrical Manholes and Electrical Duct Banks for SDS |
| 1623 | SV3-2060-C0W-850003 | 170' ELEV FLOOR SLAB, POUR 33 |
| 1624 | SV3-CA20-C0W-850001 | CA20 FLOOR SLAB, 64 & 65 |
| 1625 | SV3-PXS-PHW-ME4510 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-20A |
| 1626 | SV3-RNS-P0W-ME3512 | FABRICATION/INSTALLATION OF PIPING FOR ISO SV3-RNS-PLW-175 AND 17B |
| 1627 | SV4-2040-SSW-CV1829 | SEQUENCE 10 STRUCTURAL STEEL ERECTION |
| 1628 | SV3-2060-CEW-CV7330 | STUD WELDS ON U3TB 196'-3" EL. |
| 1629 | SV4-CA01-S4W-CV8715 | CA01-38 TEMPORARY ATTACHMENT PLATE ID |
| 1630 | SV3-PXS-PHW-ME3781 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-023 |
| 1631 | SV4-ML05-MLW-ME7978 | INSTALL CA01 PENETRATION SV4-11403-ML-P13 |
| 1632 | SV3-MS09-MEW-ME4794 | INSTALLATION OF PERMEATE PUMP & TOC REDUCTION SKID (DTS-MS-30A/B) |
| 1633 | SV3-FPS-P0W-ME4859 | (BLANK) |
| 1634 | SV4-ML05-MLW-ME7692 | INSTALL CA01 PENETRATION SV4-11205-ML-P02 |
| 1635 | SV3-2060-C0W-850004 | 170' ELEV. FLOOR SLAB POUR #4 |
| 1636 | SV4-WWS-PHW-ME5007 | INSTALLATION OF LARGE BORE WWS PIPING SUPPORTS (INCLUDING ISOMETRIC: SV4-WWS-PLW-321) |
| 1637 | SV3-MSS-PHW-ME4652 | MSS PIPE SUPPORTS FOR PIPE PACKAGE SV3-MSS-P0W-ME4651 |
| 1638 | SV3-2060-C0W-850005 | 170' ELEV. FLOOR SLAB POUR #5 |
| 1639 | SV4-2040-SSW-CV3975 | UNIT 4 TURBINE BLDG SEQUENCE 10 HANDRAIL & STAIRS |
| 1640 | SV4-2040-SSW-CV3976 | UNIT 4 TURBINE BLDG SEQUENCE 10 DECKING & GRATING |
| 1641 | SV4-2040-SSW-CV3978 | UNIT 4 TURBINE BLDG SEQUENCE 11 DECKING & GRATING |
| 1642 | SV3-CA20-C0W-850004 | CA20 FLOOR SLABS 52 - 55 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1643 | SV3-PWS-P0W-ME4948 | FABRICATE AND INSTALL ANNEX PORTABLE WATER SYSTEM (PWS) PIPNG IAW (ISOMETRICS SV3-PWS-PLW-109, 110, 139, 162 & 435) |
| 1644 | SV3-MSS-P0W-ME4690 | INSTALLATION OF MAIN STEAM PIPING |
| 1645 | SV3-MSS-P0W-ME4692 | INSTALLATION OF MAIN STEAM PIPING |
| 1646 | SV3-CWS-P0W-ME2531 | INSTALLATION AND FABRICATION OF CIRCULATING WATER (CWS) SYSTEM PIPING |
| 1647 | SV4-CA01-S4W-CV6399 | CA01-11 OLPS AND WELDED ATTACHMENTS |
| 1648 | SV4-2050-CCW-CV5844 | UNIT 4, TURBINE BUILDING 141'-3" ELEV CONCRETE, POUR #1 |
| 1649 | SV4-2050-CCW-CV5848 | UNIT 4, TURBINE BUILDING 141'3" ELEV. CONCRETE POUR #5 |
| 1650 | SV4-2050-CCW-CV5849 | UNIT 4, TURBINE BUILDING 141'3" ELEV. CONCRETE POUR #6 |
| 1651 | SV3-MSS-P0W-ME4643 | FABRICATION AND INSTALLATION OF MSS PIPING |
| 1652 | SV4-1120-CRW-CV3172 | CONTAINMENT CONCRETE REINFORCEMENT EL 80'-0" TO 80'-6" TO EL 83'-0" 84'-6" |
| 1653 | SV3-2060-C0W-850006 | UNIT 3, TURBINE BUILDING, POUR #6 |
| 1654 | SV3-CA20-CEW-850001 | CA20, Top Mech Rebar Connections Fab |
| 1655 | SV3-CA20-CEW-850002 | CA20, Top Mech Rebar Connections Install |
| 1656 | SV4-CA05-S5W-CV6025 | CA05 MISCELLANEOUS WORK |
| 1657 | SV4-CA01-S4W-CV8722 | CA01-45 TEMPORARY ATTACHMENT PLATE ID |
| 1658 | SV4-CB60-CBW-850000 | CB61 / 62 / 63 / 64 Module Installation |
| 1659 | SV4-CB50-CBW-850000 | CB51 / 52 / 53 / 54 Module Installation |
| 1660 | SV4-CA05-S5W-CV6047 | CA05 REBAR FABRICATION |
| 1661 | SV4-CA05-S5W-CV6021 | CA05-01 UNSAT IRS & N&DS - STRUCTURAL, |
| 1662 | SV3-1230-CCW-CV2442 | AUX BUILDING BATTERY RACK WALLS (29, 30, 31 & 35) UP TO EL 100'-0" |
| 1663 | SV3-CPS-PHW-ME3590 | INSTALLATION OF CPS PIPING SUPPORTS |
| 1664 | SV3-2060-C0W-850001 | 170' ELEV FLOOR SLAB, POUR #1 |
| 1665 | SV3-MS09-MEW-ME4792 | INSTALLATION OF REVERSE OSMOSIS UNIT A & B (SV3-DTS-MS-02A & -02B) |
| 1666 | SV4-1000-CPW-CV5115 | CUTTING OF SOUTH SIDE UNIT 4 NUCLEAR ISLAND MSE WALL PANELS |
| 1667 | SV3-2049-SHW-860206 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLTION IN THE UNIT 3 TURBINE BLDG BELOW ELEV 140'-6" AEA 9 FROM COLUMNS 16 TO 18 & H.05 TO K.1 |
| 1668 | SV3-MSS-PHW-ME4654 | MSS PIPE SUPPORTS FOR PIPE PACKAGE SV3-MSS-P0W-ME4653 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1669 | SV3-MSS-PHW-ME4691 | MSS PIPE SUPPORTS FOR PIPE PACKAGE SV3-MSS-P0W-ME4690 |
| 1670 | SV4-CA01-S4W-CV8717 | CA01-40 TEMPORARY ATTACHMENT ID PLATE |
| 1671 | SV4-CA01-S4W-CV8714 | CA01-37 TEMPORARY ATTACHMENT PLATE ID |
| 1672 | SV4-CA01-S4W-CV8721 | CA01-44 TEMPORARY ATTACHMENT PLATE ID |
| 1673 | SV3-PXS-PHW-ME4497 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-01M |
| 1674 | SV3-RNS-P0W-ME3447 | FABRICATION/INSTALLATION OF PIPING FOR ISO SV3-RNS-PLW-091 |
| 1675 | SV3-PXS-PHW-ME4498 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-01N |
| 1676 | SV3-PXS-PHW-ME3365 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-014 |
| 1677 | SV3-4040-EGW-EL4376 | PERFORM INSTALLATION OF UNDERGROUND COMMODITIES FOR ANNEX BLDG, AREA 1 & 3, ELEV 117'-6" BETWEEN COLUMN LINES 9&13/1&4 |
| 1678 | SV3-MS09-MEW-ME4793 | INSTALLATION OF EDI UNITS A&B (SV3-DTS-MS-04A & 04B) |
| 1679 | SV3-2060-C0W-850007 | 196'-3" ELEVATION, FLOOR SLAB POUR #8A |
| 1680 | SV3-CA20-C0W-850006 | CA20 FLOOR SLABS 56 & 57 |
| 1681 | SV4-CAS-P0W-ME1927 | FABRICATION/INSTALLATIN OF SMALL BORE CAS PIPING (INCLUDING ISOMETRICS SV4-CAS-PLW-501 & 504) |
| 1682 | SV3-2060-C0W-850002 | 170' ELEV FLOOR SLAB POUR #2 |
| 1683 | SV4-1208-SCW-CV6993 | COURSE 1 UNIT 4 FOUR PANEL SHIELD BUILDING |
| 1684 | SV4-1220-CRW-CV4190 | UNIT 4 AUXILIARY BUILDING INSTALLATION OF REINFORCING STEEL FOR FLOORS AT EL 82'-6" (SLAB PLACEMENTS #1 - 15) |
| 1685 | SV3-PXS-PHW-ME4502 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-02F |
| 1686 | SV4-CA20-S5W-CV7371 | CA20 MISCELLANEOUS WORK |
| 1687 | SV4-CA01-S4W-CV8707 | CA01-30 Temporary Attachments |
| 1688 | SV4-CA01-S4W-CV8708 | CA01-31 Temporary Attachments |
| 1689 | SV4-CA01-S4W-CV8709 | CA01-32 Temporary Attachments |
| 1690 | SV4-CA01-S4W-CV8710 | CA01-33 Temporary Attachments |
| 1691 | SV4-CA01-S4W-CV8711 | CA01-34 Temporary Attachments |
| 1692 | SV4-CA01-S4W-CV8713 | CA01-36 Temporary Attachments |
| 1693 | SV4-CA01-S4W-CV8723 | CA01-46 Temporary Attachment PLATE ID |
| 1694 | SV3-4042-ERW-860256 | INSTALLATION OF CONDUIT SLEEVES FOR RACEWAY PENETRATIONS, ANNEX BUILDING, AREA 2, ELEV. 117'-6". |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1695 | SV3-2047-SHW-860204 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE UNIT 3 TURBINE BUILDING, BELOW EL 140'-6" AREA 7 FROM COLUMNS 18 TO 20 & I2 TO K.1 |
| 1696 | SV3-2049-SHW-860205 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE UNIT 3 TURBINE BUILDING, BELOW EL 140'-6" AREA 9 FROM COLUMNS 18 TO 20 & I2 TO H.05 |
| 1697 | SV3-ECS-ESW-EL7178 | INSTALL TURBINE BLDG ECS EQUIPMENT, MV SWITCHGEAR ECS-ES-5, ROOM 20502 EKEV 141'-3" |
| 1698 | SV3-ECS-ESW-EL7175 | INSTALL TURBINE BLDG ECS EQUIPMENT, MV SWITCHGEAR ECS-ES-56, ROOM 20501 EKEV 141'-3" |
| 1699 | SV4-ML05-MLW-ME7938 | INSTALL CA01 ASME PROCESS PIPE PENETRATION SV4-11502-ML-P02 |
| 1700 | SV4-ML05-MLW-ME7956 | INSTALL CA01 PENETRATIONS SV4-11303-ML-P07, SV4-11503-ML-P01, & SV4-11503-ML-P03 |
| 1701 | SV4-ML05-MLW-ME7957 | INSTALL CA01 PENETRATIONS SV4-11303-ML-P01, SV4-11303-ML-P02, & SV4-11303-ML-P03 |
| 1702 | SV4-ML05-MLW-ME7976 | INSTALL PENETRATIONS SV4-11403-P02, SV4-11403-ML-P03, AND SV4-11403-ML-I01 |
| 1703 | SV4-ML05-MLW-ME7981 | INSTALL SV4 CA01 PENETRATION SV4-11402-ML-P02 |
| 1704 | SV3-CA20-S4W-850001 | CA20 CASK LOADING PIT LEAK CHASE & LINER PLATE INSTALLATION |
| 1705 | SV3-CA20-S4W-850003 | CA20-SPENT FUEL POOL LEAK CHASE & LINER PLATE INSTALLATION |
| 1706 | SV4-MS30-MSW-ME7103 | INSTALLATION OF THE ANTISCALANT SKID (MS-05C), CHLORINE CONTROL SKID (MS06) AND CAUSTIC SKIS (MS-02D) |
| 1707 | SV3-EDS-DBW-EL3127 | INSTALL ANNEX BLDG EDS1-DB1 BATTERY RACKS, ROOM 40307 |
| 1708 | SV3-PLS-JDW-EL7556 | INSTALL TURBINE BLDG PLS AND ASSOCIATED DDS & SMS - "JD" EQUIPMENT IN ROOM 20308 ELEV 100'0" |
| 1709 | SV3-PLS-JDW-EL7173 | INSTALL TURBINE BLDG. PLS EQUIPMENT ROOM 20503 ELEV 141'3" |
| 1710 | SV3-CA20-S4W-850002 | CA20 CASK WASHDOWN PIT LEAK CHASE & LINER PLATE |
| 1711 | SV3-CA20-S4W-850004 | CA20 FUEL TRANSFER CANAL LEAK CHASE & LINER PLATE |
| 1712 | SV3-ECS-ESW-EL7179 | INSTALL TURBINE BLDG ECS EQUIPMENT, MV SWITCHGEAR ECS-ES-3, ROOM 20502, ELEV 141'3" |
| 1713 | SV3-EDS-DBW-EL3128 | INSTALL ANNEX BLDG EDS3-DB1 BATTERY RACKS, ROOM 40307 |
| 1714 | SV0-DFS-ERW-EL2424 | DFS DUCTBANK NORTH OF TRANSFORMER AREA (PHASE 2) |
| 1715 | SV3-1230-SSW-CV4312 | AUX BLD STRUCTURAAL STEEL 82'6" TO 100'-0" AREA 3 AND 4 |
| 1716 | SV3-1230-CCW-CV2443 | AUX BUILDING BATTERY RACK WALLS (32, 33, 34, 36 & 37) UP TO EL 100'-0" |
| 1717 | SV3-PXS-PHW-ME3785 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-02D |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1718 | SV3-1230-SSW-CV4313 | AUX BLD STRUCTURAL STEEL 82'-6" TO 100'-0" AREA 5 AND 6 |
| 1719 | SV4-4000-SSW-850000 | BOLT QUALIFICATION |
| 1720 | SV4-MY45-MYW-ME6721 | INSTALLATION OF TURBINE DECK SPRINGS/DAMPERS |
| 1721 | SV3-2037-SHW-860239 | ELECTRICAL CABLE TRAY SUPPORT INSTALLATION IN THE TURBINE BUILDING, ELEVATION 100', AREA 7 ROOM 20300 (TRAPEZE) |
| 1722 | SV4-1000-C0W-850000 | CONCRETE UNDER CONTAINMENT VESSEL, 8Bx |
| 1723 | SV3-CCS-P0W-ME3441 | FABRICATE AND INSTALL LARGE BORE CCS PIPING (INCLUDING ISOMETRIC SV3-CCS-PLW-330 AND SV3-CCS-PLW-690) |
| 1724 | SV3-WLS-P0W-ME3802 | INSTALLATION OF SMALL BORE WLS PIPING (ISOMETRICS SV3-WLS-PLW-261, 271, 281) |
| 1725 | SV3-WLS-P0W-ME3818 | INSTALLATION OF SMALL BORE WLS PIPING (ISOMETRIC SV3-WLS-PLW-284) |
| 1726 | SV3-2060-C0W-850011 | UNIT 3, TURBINE BUILDING, 183'-1-1/2" ELEVATED SLAB |
| 1727 | SV3-2141-C0W-850002 | 1ST BAY, 117' ELEV, FLOOR SLAB, POUR #2 |
| 1728 | SV3-2141-C0W-850004 | 117'-6" ELEV, FLOOR SLAB POUR #4 |
| 1729 | SV4-2141-C0W-850004 | 1ST BAY, 117'-6" ELEV, FLOOR SLAB POUR #4 |
| 1730 | SV3-ML05-MLW-ME4961 | INSTALLATION OF CA01 PENETRATIONS |
| 1731 | SV3-CCS-P0W-ME3439 | FABRICATE AND INSTALL LARGE BORE CCS PIPING (INCLUDING ISOMETRIC SV3-CCS-PLW-300 AND SV3-CCS-PLW-670) |
| 1732 | SV3-1233-ERW-EL6069 | U3 AUXILIARY BUILDING: INSTALL WALL PENETRATIONS FOR INTERIOR AND EXTERIOR WALLS ELEVATION 100'-0" - 117'-6" AREAS 3 & 4 |
| 1733 | SV3-WGS-PHW-ME3859 | FABRICATION/INSTALLATION OF SMALL BORE WGS PIPE SUPPORTS FOR ISOMETRICS SV3-WGS-PLW-420, -422 |
| 1734 | SV4-WWS-P0W-860277 | INSTALLATION OF WASTE WATER SYSTEM (WWS) DRAINS/PIPING FOR 140' SLAB 5 |
| 1735 | SV4-WWS-P0W-860278 | INSTALLATION OF WASTE WATER SYSTEM (WWS) DRAINS/PIPING FOR 140' SLAB 6 |
| 1736 | SV3-ECS-ESW-EL7181 | INSTALL TURBINE BLDG ECS EQUIPMENT, LOCAL SWITCHGEAR CONTROL PANELS ECS-EP-003, 004, 005, 006 ROOMS 20501 & 20502 ELEV 141'3 |
| 1737 | SV4-1220-CCW-CV4192 | UNIT 4 NUCLEAR ISLAND AUX BUILDING CONCRETE PLACEMENT FOR SLABS AT ELEVATION 82'-6" - AREAS 1 - 6 (SLAB PLACEMENTS 1- 15) |
| 1738 | SV4-CA20-S5W-CV5320 | CA20 GUIDE PIN MOUNTING PLATE AND ALIGNMENT/GUIDE PIN COLLAR INSTALLATION |
| 1739 | SV3-4000-ERW-EL7439 | FABRICATE AND INSTALL TYPCIAL SUPPORTS TUYPE C14 FOR FIELD ROUTED CONDUIT IN THE ANNEX BUILDING |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1740 | SV3-4000-ERW-EL7441 | FABRICATE AND INSTALL TYPICAL SUPPORTS TUYPE C17 FOR FIELD ROUTED CONDUIT IN THE ANNEX BUILDING |
| 1741 | SV3-4000-ERW-EL7440 | FABRICATE AND INSTALL TYPICAL SUPPORTS TUYPE C15 FOR FIELD ROUTED CONDUIT IN THE ANNEX BUILDING |
| 1742 | SV3-4000-ERW-EL7442 | FABRICATE AND INSTALL TYPICAL SUPPORTS TYPE C18 FOR FIELD ROUTED CONDUIT IN THE ANNEX BUILDING |
| 1743 | SV4-2141-C0W-850001 | UNIT 4 TURBINE BUILDING FIRST BAY 117'-6" FLOOR SLAB REINFORCING STEEL |
| 1744 | SV3-RWS-ERW-EL0864 | Installation of Electrical Underground Commodities (Manholes & Duct Banks) for the (RWS) Raw Water System to the River Intake Structure |
| 1745 | SV0-SDS-P0W-ME1195 | SDS LINES FROM BLDG #306 TO GRINDER PUMP MS-504 AND LIFT STATION MS-503 |
| 1746 | SV0-SDS-MPW-ME1205 | GRINDER PUMP MS-504 |
| 1747 | SV4-WWS-P0W-860276 | INSTALLATION OF WASTE WATER SYSTEM (WWS) DRAINS/PIPING FOR 140' SLAB1 |
| 1748 | SV3-4000-ERW-EL7438 | FABRICATE & INSTALL TYPICAL SUPPORTS TYPE C13 FOR FIELD ROUTED CONDUIT IN THE ANNEX BUILDING |
| 1749 | SV3-CWS-ERW-EL0315 | Install Electrical Manholes and Electrical Duct Banks for CWS |
| 1750 | SV3-4032-SHW-EL4041 | INSTALL CABLE TRAY SUPPORTS ANNEX BLDG AREA 2, ROOM 40303 |
| 1751 | SV3-4032-SHW-EL4040 | INSTALL CABLE TRAY SUPPORTS ANNEX BLDG AREA 2, ROOM 40303 & 40351 |
| 1752 | SV3-4032-SHW-EL4042 | INSTALL CABLE TRAY SUPPORTS ANNEX BLDG AREA 2, ROOM 40327 |
| 1753 | SV3-C0S7-CCW-CV0340 | Electrical Duct bank for Unit 3 CWS |
| 1754 | SV3-2060-C0W-850009 | 196'-3" ELEV FLOOR SLAB POUR # 8C |
| 1755 | SV3-2060-C0W-850008 | 196¿-3" ELEV. FLOOR SLAB, POUR # 8B |
| 1756 | SV0-0000-XEW-CV0346 | Temporary Turbine Bldg Construction Support |
| 1757 | SV4-4030-EGW-EL5436 | PERFORM INSTALLATION OF UNDERGROUND COMMODITIES (EGS GROUNDING) FOR THE ANNEX BLDG AREA 2 BETWEEN COLUMNS 4.1 & 9 |
| 1758 | SV3-FWS-P0W-ME3809 | FABRICATION AND INSTALLATION OF FWS PIPING |
| 1759 | SV3-MSS-PHW-ME4648 | MSS PIPE SUPPORTS FOR PIPE PACKAGE SV3-MSS-P0W-ME4647 |
| 1760 | SV4-CA01-S4W-CV6491 | CA01 ELEV 87.5 & BELOW OLPS AND WELDED ATTACHMENTS |
| 1761 | SV0-0000-XSC-CV0349 | INSTALLATION OF ROLLER COMPACTED CONCRETE (RCC) FOR THE HEAVY HAUL ROAD |
| 1762 | SV4-CA01-S4W-860304 | CA01-02 SUPPORTING LEG INSTALLATION |
| 1763 | SV3-CA01-S4W-CV4079 | CA01-15 OLP AND PERM WELD ATTACHMENTS |
| 1764 | SV4-2101-CEW-CV5806 | UNIT 4, TURBINE BUILDING FIRST BAY WALLS UP TO 122', EMBEDS AND ANCHOR BOLTS |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1765 | SV3-VWS-PLW-ME0504 | INSTALLATION OF SMALL BORE VWS PIPING (INCLUDES ISOMETRIC SV3-VWS-PLW-486). |
| 1766 | SV3-FPS-P0W-ME4182 | INSTALLATION OF LARGE BORE FPS PIPING (INCLUDES ISOMETRICS SV3-FPS-PLW-718, -719) |
| 1767 | SV3-WWS-PHW-ME1375 | INSTALLATION OF LARGE BORE WWS PIPING SUPPORTS (INCLUDES ISOMETRICS SV3-WWS-PLW-312, 314) |
| 1768 | SV3-FPS-PHW-ME4840 | INSTALLATION OF ANNEX FPS PIPING SUPPORTS FOR WP (SV3-FPS-PLW-ME4839) |
| 1769 | SV4-WRS-PLW-ME5031 | CA20 LEAK CHASE TESTING PROCEDURE FOR CHANNELS CONNECTING TO THE FUEL TRANSFER CANAL (FHS-MT-02) |
| 1770 | SV4-FPS-THW-ME7863 | Hydro Test the Unit 4 Fire Protection Piping (FPS) Piping on Isometrics (SV4-FPS-PLW-964,965,966,967,96AK,96AM,96AL,96AW,96AX,96BA) |
| 1771 | SV4-WWS-P0W-ME7548 | INSTALLATION OF ANNEX BLDG WWS EMBEDDED PIPING (ISOMETRIC SV4-WWS-PLW-400, 402, 402, 403, 404,405, 406, 407, 408, 409, 968, 972, 973) |
| 1772 | SV4-WWS-P0W-ME7546 | INSTALLATION OF ANNEX BLDG WWS EMBEDDED PIPING (ISOMETRIC SV4-WWS-PLW-410, 411, 412, 413, 418, 951, 953, 970, 971) |
| 1773 | SV4-MSS-P0W-800000 | INSTALL MAIN STEAM SYSTEM PIPING FROM AUX BUILDING TO HP TURBINE |
| 1774 | SV3-FPS-PHW-ME0695 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWINGS SV3-FPS-PLW-820, 825, 830 |
| 1775 | SV4-FPS-PHW-ME4999 | FABRICATION/INSTALLATION OF FPS PIPE SUPPORTS (INCLUDING ISOMETRICS SV4-FPS-PLW-810, 815) |
| 1776 | SV3-MG20-MEW-ME6641 | INSTALLATION OF MAIN GENERATOR STATOR |
| 1777 | SV3-WLS-PLW-ME0535 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES ISOMETRICS SV3-WLS-PLW-33B, -33G, -33H, -33K) |
| 1778 | SV3-WLS-PHW-ME0821 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING WLS-PLW-190 |
| 1779 | SV3-WLS-PHW-ME0831 | INSTALLATION OF SMALL BORE WLS PIPING SUPPORTS FOR ISOMETRICS SV3-WLS-PLW-980, -981 |
| 1780 | SV3-VWS-PHW-ME2799 | INSTALLATION OF VWS SUPPORTS FOR ISOMETRICS SV3-VWS-PLW-20K. |
| 1781 | SV3-CCS-PHW-ME4302 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-CCS-PLW-392 |
| 1782 | SV3-CVS-P0W-ME3900 | INSTALLATION OF SMALL BORE CVS PIPING (INCLUDES SV3-CVS-PLW-65C AND 65F), REQUEST CQC FOR 65F BJA 4/16/15 |
| 1783 | SV3-CVS-PHW-ME4187 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-CVS-PLW-65C |
| 1784 | SV4-CA20-S4W-CV6817 | CA20-31 Temporary Attachments - FLOOR |
| 1785 | SV4-CA20-S4W-CV6820 | CA20-32 Temporary Attachments/Floor |
| 1786 | SV4-CA20-S5W-CV6826 | CA20-34 Temporary Attachments |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1787 | SV4-CA20-S4W-CV6838 | CA20-37 Temporary Attachments |
| 1788 | SV4-WRS-P0W-ME5359 | FABRICATION/INSTALLATION OF SMALL BORE WRS LEAK CHASE PIPING INCLUDING SV4-WRS-PLW-84D, -840 |
| 1789 | SV3-DWS-PHW-ME7043 | INSTALLATION OF ANNEX BLDG DWS PIPE SUPPORTS (ISOMETRICS SV3-DWS-PLW-180, 181, 182, & 190) |
| 1790 | SV4-WRS-P0W-ME5365 | Fabrication/Installation of Small Bore WRS Leak Chase Piping Including SV4-WRS-PLW-82E, -82K, -825, -826, -827, -828 |
| 1791 | SV3-1130-C0W-850001 | Reinforced Concrete Inside Containment El. 87'-6" to 96'-0" East Side (Layers 6 & 7) |
| 1792 | SV3-CB26-CBW-850000 | CB26 MODULE INSTALLATION |
| 1793 | SV3-CB27-CBW-850000 | CB27 MODULE INSTALLATION |
| 1794 | SV3-CB28-CBW-850000 | CB28 MODULE INSTALLATION |
| 1795 | SV3-CB31-CBW-850000 | CB31 MODULE INSTALLATION |
| 1796 | SV3-CB33-CBW-850000 | CB33 MODULE INSTALLATION |
| 1797 | SV3-CB34-CBW-850000 | CB34 MODULE INSTALLATION |
| 1798 | SV3-CB35-CBW-850000 | CB35 MODULE INSTALLATION |
| 1799 | SV3-CB36-CBW-850000 | CB36 MODULE INSTALLATION |
| 1800 | SV3-CB37-CBW-850000 | CB37 MODULE INSTALLATION |
| 1801 | SV3-CB38-CBW-850000 | CB38 MODULE INSTALLATION |
| 1802 | SV3-CB39-CBW-850000 | CB39 MODULE INSTALLATION |
| 1803 | SV3-CB41-CBW-850000 | CB41 MODULE INSTALLATION |
| 1804 | SV3-CB42-CBW-850000 | CB42 MODULE INSTALLATION |
| 1805 | SV3-CB43-CBW-850000 | CB43 MODULE INSTALLATION |
| 1806 | SV3-CB44-CBW-850000 | CB44 MODULE INSTALLATION |
| 1807 | SV3-CB45-CBW-850000 | CB45 MODULE INSTALLATION |
| 1808 | SV3-CB46-CBW-850000 | CB46 MODULE INSTALLATION |
| 1809 | SV3-CB47-CBW-850000 | CB47 MODULE INSTALLATION |
| 1810 | SV3-2060-CRW-CV8366 | UNIT 3, TURBINE BUILDING 170' ELEVATED SLAB REBAR FOR POUR #3 |
| 1811 | SV3-2060-CRW-CV8367 | UNIT 3 TURBINE BUILDING 170' SLAB REBAR FOR POUR #4 |
| 1812 | SV3-2060-CRW-CV8365 | UNIT 3 TURBINEBUILDING 170' ELEV REBAR, POUR #2 |
| 1813 | SV4-2101-CRW-CV5808 | UNIT 4, TURBINE BUILDING FIRST BARY WALLS, TERMINATORS UP TO 122' |
| 1814 | SV3-2060-CRW-CV8364 | UNIT 3 TURBINE BUILDING 170' ELEVATED SLAB REBAR FOR POUR #1 |
| 1815 | SV3-2060-CRW-CV8369 | UNIT 3 TURBINE BUILDING 170' ELEVATED DECK REBAR FOR POUR #6 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1816 | SV3-REFDOC-NI3-850000 | Foreman's Book: Shield Building SC Portion - Concrete Placements |
| 1817 | SV3-1208-C0W-850000 | UNIT 3 AUXILIARY CYLINDRICAL WALL - CIVIL - ELECTRICAL PENETRATION ASSEMBLY SLEEVES |
| 1818 | SV3-1208-C0W-850001 | UNIT 3 AUXILIARY EL. 100 FT. - CYLINDRICAL WALL - CIVIL - RC01 |
| 1819 | SV3-1208-C0W-850002 | AUXILIARY EL. 100 FT. - CYLINDRICAL WALL - CIVIL - RC02 |
| 1820 | SV3-1208-C0W-850003 | CYLINDRICAL WALL RC03 |
| 1821 | SV3-1208-C0W-850004 | UNIT 3 AUXILIARY EL. 100 FT. - CYLINDRICAL WALL - CIVIL - RC04 |
| 1822 | SV3-1208-C0W-850005 | UNIT 3 AUXILIARY EL. 100 FT. - CYLINDRICAL WALL - CIVIL - RC05 |
| 1823 | SV4-WRS-P0W-ME5366 | Fabrication/Installation of Small Bore WRS Leak Chase Piping Including SV4-WRS-PLW-82D, -82F, -82G, -880 |
| 1824 | SV4-WRS-P0W-ME5364 | Fabrication/Installation of Small Bore WRS Leak Chase Piping Including SV4-WRS-PLW-824, -829 |
| 1825 | SV3-WLS-PHW-ME3484 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWINGS SV3-WLS-PLW-011 |
| 1826 | SV3-DWS-P0W-ME7046 | INSTALLATION OF ANNEX BLDG DWS PIPING (ISOMETRICS SV3-DWS-PLW-142, -242, -256 |
| 1827 | SV3-1230-C0W-850000 | 100'-0" ELEV WALLS, CL Q, WALL 68 |
| 1828 | SV3-1230-C0W-850004 | 100'-0" ELEV WALLS, CL I, WALL 93 |
| 1829 | SV3-1230-C0W-850010 | 100'-0" ELEV WALLS, CL J, WALL 86 |
| 1830 | SV3-1230-C0W-850011 | 100'-0" ELEV WALLS, CL1, WALL 74 |
| 1831 | SV3-1230-C0W-850012 | 100'-0" ELEV WALLS, CL N, WALL 76 |
| 1832 | SV3-1232-C0W-850001 | 100'-0" Elev. Concrete Beam for Floor Slab, Area 2 |
| 1833 | SV4-1220-CRW-CV4322 | UNIT 4 NUCLEAR ISLAND AUXILIARY BUILDING AREAS 3 THRU 6 - INSTALLATION OF REINFORCING STEEL ON INTERIOR WALLS FROM ELEV. 82'6" TO 100'0" (WALL PLACEMENTS 72 THRU 81) |
| 1834 | SV3-PWS-PHW-ME4947 | INSTALLATION OF ANNEX POTABLE WATER SYSTEM (PWS) PIPING SUPPORTS FOR WP (SV3-PWS-P0W-ME4946) |
| 1835 | SV3-1231-CRW-850000 | FOREMAN'S BOOK: AUXILIARY NORTH EL. 100' to 117'-6" CIVIL REBAR |
| 1836 | SV3-1120-CRW-850000 | FOREMAN'S BOOK: CONTAINMENT EL. 84'-6" to 107'-2" CIVIL REBAR |
| 1837 | SV3-CB00-CBW-850000 | FOREMAN'S BOOK: CONTAINMENT CB MODULES |
| 1838 | SV3-1208-SCW-CV7588 | MS/FW PANEL |
| 1839 | SV3-WRS-P0W-ME4453 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES ISOMETRIC SV3-WRS-PLW-836 |
| 1840 | SV4-2050-CEW-CV8140 | UNIT 4 TURBINE BUILDING FORM WORK EMBEDS ANCHOR BOLTS ACTIVITIES POUR 1 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1841 | SV4-2050-CEW-CV8143 | Unit 4, Turbine Building, 141' Elev. Formwork / Embeds / Anchor Bolts, Pour 4 |
| 1842 | SV4-2050-CEW-CV8144 | Unit 4, Turbine Building, 141' Elev. Formwork / Embeds / Anchor Bolts, Pour 5 |
| 1843 | SV4-2050-CEW-CV8145 | Unit 4, Turbine Building, 141'-3" Elev. Formwork / Embeds / Anchor Bolts, Pour 6 |
| 1844 | SV4-CA01-S4W-CV6492 | CA01-36 SUB MODULE INSTALLATION |
| 1845 | SV3-1210-ERW-850024 | INSTALL CABLE TRAY IN ROOMS 12111/12112 |
| 1846 | SV3-1210-ERW-850046 | INSTALL CABLE TRAY IN ROOM 12113 |
| 1847 | SV3-CA20-CCW-CV5116 | UNIT 3 CA20 WALL CONCRETE PLACEMENT FROM 87¿3¿ TO 128¿1¿ (K2 AND L2 COLUMN LINES ¿ PLACEMENT #2 |
| 1848 | SV0-8700-CCW-TP0730 | INSTALLATION AND SET-UP OF NITROGEN COOLING SYSTEMS |
| 1849 | SV4-RWS-ERW-EL0865 | Installation of Electrical Underground Commodities (Manholes & Duct Banks) for the (RWS)Raw Water System to the River Intake Structure |
| 1850 | SV0-1000-EWW-TP0866 | Temporary Power to Nuclear Island Unit 4 |
| 1851 | SV3-CCS-PLW-ME0876 | Fabricate and Install CCS Piping Iso SV3-CCS-PLW-740 |
| 1852 | SV3-CCS-PLW-ME0877 | Fabricate and Install CCS Piping Iso SV3-CCS-PLW-750 |
| 1853 | SV0-670-EWW-TP0880 | Temporary Power to Rotor Storage Building (324) |
| 1854 | SV3-1124-ERW-EL5406 | FABRICATION AND INSTALLATION OF DESIGN ROUTED CONDUIT SUPPORTS IN ROOM 11206 PXS-A AT ELEVATION 84' |
| 1855 | SV3-PLS-JDW-EL3126 | INSTALL ANNEX BLDG. PLS EQUIPMENT, ROOM 40310 |
| 1856 | SV3-PLS-JDW-EL3122 | INSTALL ANNEX BLDG. PLS EQUIPMENT, ROOM 40308 |
| 1857 | SV3-1123-ERW-EL5403 | FABRICATION AND INSTALLATION OF DESIGN ROUTED CONDUIT SUPPORTS IN ROOM 11207 PXS-B AT ELEVATION 84' |
| 1858 | SV3-1120-ERW-EL7084 | FABRICATION AND INSTALLATION OF DESIGN ROUTED CONDUIT SUPPORTS IN ROOM 11204, EL 85'-6" |
| 1859 | SV3-1120-ERW-EL2422 | FABRICATION AND INSTALLATION OF DESIGN ROUTED CABLE TRAY SUPPORTS IN ROOM 11202 AT ELEVATION 84' 6" TO 107' 2" |
| 1860 | SV3-1120-ERW-EL2848 | FABRICATION AND INSTALLATION OF DESIGN ROUTED CONDUIT SUPPORTS IN ROOM 11202 EL 84'-6" THROUGH 107'-2" |
| 1861 | SV3-1123-ERW-EL5404 | FABRICATION AND INSTALLATION OF DESIGN ROUTED CONDUIT SUPPORTS IN ROOM 11207 PXS-B AT ELEVATION 84'-6" |
| 1862 | SV3-1124-ERW-EL5405 | FABRICATION AND INSTALLATION OF DESIGN ROUTED CONDUIT SUPPORTS IN ROOM 11206 PXS-A AT ELEVATION 84'-6" |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1863 | SV4-4030-EGW-EL5437 | PERFORM INSTALLATION OF UNDERGROUND COMMODITIES (EGS GROUNDING) FOR THE ANNEX BLDG. AREA 3 BETWEEN COLUMNS 2 & 4.1 |
| 1864 | SV4-WLS-P0W-ME3116 | INSTALLATION OF LARGE BORE WLS PIPING LINES WLS-PL-L020, L031, L077 & L131A OF ISOMETRIC SV4-WLS-PLW-750 |
| 1865 | SV0-REFDOC-BOP-860441 | Raw Water Intake - Foreman's Book |
| 1866 | SV3-WLS-PLW-ME0941 | Fabricate and Install Small Bore Elevation 1 WLS Piping Iso SV3-WLS-PLW-851 |
| 1867 | SV3-WLS-PLW-ME0942 | Fabricate and Install Small Bore Elevation 1 WLS Piping Iso SV3-WLS-PLW-852 |
| 1868 | SV0-8000-EWW-TP0945 | Electrical Power Feeder Installation to Valve Shop (BLD 184) |
| 1869 | SV4-WWS-PLW-ME0984 | TURBINE BUILDING 82FT.-9IN. ELEVATION EMBEDDED WWS PIPING PACKAGE 3 |
| 1870 | SV4-CWS-XEW-CV1035 | UNIT 4, CIVIL INSTALLATION OF THE CWS PIPE (PHASE III) |
| 1871 | SV3-WLS-PHW-ME1039 | Fabrication/Installation of pipe Supports for Isometric Drawing WLS-PLW-042 |
| 1872 | SV3-WLS-PHW-ME1041 | Fabrication/ Installation of pipe Supports for Isometric Drawing WLS-PLW-04B |
| 1873 | SV3-WLS-PHW-ME1043 | Fabrication/ Installation of pipe Supports for Isometric Drawing WLS-PLW-046 |
| 1874 | SV3-WLS-PHW-ME1045 | Fabrication/ Installation of pipe Supports for Isometric Drawing WLS-PLW-754 |
| 1875 | SV0-PWS-PLW-TP1046 | INSTALLATION OF MPW TEMPORARY WATER FILTRATION UNIT. |
| 1876 | SV3-CWS-EQW-EL1049 | ELECTRICAL CONTINUITY INSTALLATION FOR CWS (PHASE 3) |
| 1877 | SV4-TCS-PHW-ME5477 | INSTALLATION AND FABRICATION OF TURBINE BUILDING CLOSED COOLING WATER SYSTEM (TCS) PIPING SUPPORT |
| 1878 | SV4-4030-EGW-EL5435 | PERFORM INSTALLATION OF UNDERGROUND COMMODITIES (EGS GROUNDING) FOR THE ANNEX BLDG AREA 1 BETWEEN COLUMNS 9 & 13 |
| 1879 | SV4-CWS-EQW-EL1050 | ELECTRICAL CONTINUITY INSTALLATION FOR CWS (PHASE 3) |
| 1880 | SV3-WLS-PHW-ME1051 | Fabrication /Installation of Pipe Supports for Isometric Drawing WLS-PLW-64P |
| 1881 | SV3-WLS-PHW-ME1052 | Fabrication /Installation of Pipe Support for Isometric Drawing WLS-PLW-64Q |
| 1882 | SV3-CCS-PHW-ME1055 | Fabrication/Installation of Pipe Supports for Isometric Drawing CCS-PLW-740 |
| 1883 | SV3-DWS-PHW-ME1058 | Fabrication/Installation of Pipe Supports for Isometric Drawing DWS-PLW-773 |
| 1884 | SV3-SFS-P0W-ME3648 | FABRICATION/INSTALLATION OF PIPING FOR ISO SV3-SFS-PLW-538 |
| 1885 | SV0-SDS-PLW-ME1098 | FABRICATE SANITARY DRAIN PIPING BETWEEN LIFT STATIONS MS-501 AND MS-502. |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1886 | SV0-SDS-PLW-ME1099 | FABRICATE AND INSTALL SANITARY DRAIN PIPING BETWEEN LIFT STATIONS MS-502 AND MS-503. |
| 1887 | SV3-ML05-MLW-ME1104 | ASME SECTION III - ATTACH CODE DATA PLATES ON CA01 PENETRATIONS |
| 1888 | SV3-CWS-PLW-ME1114 | UNIT 3 CWS FROM PCCP TO TURBINE BUILDING |
| 1889 | SV0-SDS-PLW-ME1125 | INSTALL SANITARY DRAIN LIFT STATION MS-502. |
| 1890 | SV0-1000-EWW-TP1149 | Installation of Temporary Power on East Side of CR-10 PAD |
| 1891 | SV0-SDS-PLW-ME1153 | FABRICATE AND INSTALL SANITARY DRAIN PIPING FROM BUILDING 301 TO MANHOLE MH-57. |
| 1892 | SV0-ZRS-EWW-EL1347 | ZRS TIE-IN UNDER 100 YEAR DITCH |
| 1893 | SV4-1220-CPW-CV1418 | FABRICATION OF UNIT 4 AUXILIARY BULIDING PRECAST CONCRETE PANELS AT EL.82'6" |
| 1894 | SV3-WLS-PLW-ME1466 | Fabricate and Install WLS Piping Lines WLS-PL-L078 & L131B of Iso SV3-WLS-PLW-731 |
| 1895 | SV3-CVS-PLW-ME1471 | Fabricate and Install Small Bore CVS Piping Isometric # SV3-CVS-PLW-803 |
| 1896 | SV3-CAS-PLW-ME1473 | Fabricate and Install Small Bore CAS Piping Isometric # SV3-CAS-PLW-729 |
| 1897 | SV0-ZRS-EWW-TP1545 | Temporary Storage Power for Plant Transformers |
| 1898 | SV0-SDS-CKW-ME1573 | INSTALL SANITARY DRAIN MANHOLES SV0-SDS-MH-53, AND SV0-SDS-MH-57. |
| 1899 | SV0-SDS-PLW-ME1642 | FABRICATE AND INSTALL SANITARY DRAIN PIPING FROM MANHOLE MH-57 TO MANHOLE MH-12 AND TO SNC CAPPED FUTURE CONNECTION FROM MANHOLE MH-57. |
| 1900 | SV0-MH90-CCW-CV1644 | HLD Concrete Counterweights Phase II |
| 1901 | SV4-FWS-PNW-ME1671 | UNIT 4 TURBINE BUILDING EL 100'-0": INSULATION OF EMBEDDED FWS PIPING |
| 1902 | SV4-FWS-THW-ME1672 | UNIT 4 TURBINE BUILDING EL 100'-0" HYDROSTATIC TESTING OF EMBEDDED FWS PIPING |
| 1903 | SV0-8000-EWW-TP1687 | TEMPORARY POWER TO CBI HAZARDOUS MATERIALS STORAGE AREA |
| 1904 | SV3-KB38-KBW-ME1688 | INSTALLTION OF MODULE KB38- WLS MONITOR PUMP B |
| 1905 | SV3-KB37-KBW-ME1693 | INSTALLATION OF MODULE KB37 - WLS MONITOR PUMP A |
| 1906 | SV4-1210-CEW-CV1737 | U4 AUXILIARY BUILDING EMBED PLATES-EL 66'6" - EXTERIOR WALLS |
| 1907 | SV0-SDS-CKW-ME1719 | INSTALL SANITARY DRAIN MANHOLE SV0-SDS-MH-67. |
| 1908 | SV4-ML05-MLW-ME1844 | ATTACHMENT OF WELDED COUPLINGS TO EMBEDDED PIPING PENETRATIONS 66'6"-82'6" WALLS ONLY |
| 1909 | SV3-CCS-PLW-ME0496 | INSTALLATION OF SMALL BORE CCS PIPING (INCLUDES ISOMETRIC: SV3-CCS-PLW-521) |
| 1910 | SV0-ZFS-ERW-EL1863 | PERFORM INSTALLATION OF UNDERGROUND COMMODITIES ZFS DUCT BANK ELEV. 240' NORTH OF BUILDING 301 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1911 | SV0-MH90-MHW-RI1879 | REPAIRING THE HLD |
| 1912 | SV3-WRS-PHW-ME5040 | FABRICATION/INSTALLATION OF CONSTRUCTION AID SUPPORTS FOR CA20 WRS PIPING |
| 1913 | SV3-DWS-PLW-ME0464 | INSTALLATION OF SMALL BORE DWS PIPING |
| 1914 | SV3-CCS-PLW-ME0492 | INSTALLATION OF SMALL BORE CCS PIPING (INCLUDES ISOMETRIC: SV3-CCS-PLW-530, 550) |
| 1915 | SV3-WLS-PLW-ME0580 | INSTALLATION OF LARGE BORE WLS PIPING (INCLUDES ISOMETRICS SV3-WLS-PLW-93C, 940, 445) |
| 1916 | SV3-4030-EGW-EL1854 | PERFORM INSTALLATION OF UNDERGOUND COMMODITIES (EGS-GROUNDING) FOR THE ANNEX BLDG., AREA 3, ELEV. 100' & 107'-BETWEEN COLUMN LINES (2) TO (4.1) |
| 1917 | SV4-KB13-KBW-ME2057 | KB13 SUMP (WRS-MT-01) INSTALLATION - PORTION 2 ONLY |
| 1918 | SV4-KB10-KBW-ME2058 | KB10 SUMP (WWS-MT-06) INSTALLATION-PORTION 2 ONLY |
| 1919 | SV4-1000-C0W-850002 | CONCRETE UNDER CONTAINMENT VESSEL - 8Bz |
| 1920 | SV3-FWS-P0W-ME3810 | FABRICATION AND INSTALLATION OF FWS PIPING |
| 1921 | SV3-SDS-P0W-860436 | INSTALLATION OF ANNEX BUILDING SDS PIPE (ISO SV3-SDS-PLW-420, 422, 423) |
| 1922 | SV3-2060-SSW-850112 | TB12 STAIRS AND HANDRAILS |
| 1923 | SV3-CA01-CAW-855001 | CA01 WEST TOP PLATE INSTALLATION |
| 1924 | SV3-2060-C0W-850010 | 196¿-3" ELEV. FLOOR SLAB, POUR # 8D |
| 1925 | SV4-1233-C0W-850001 | 100' ELEV., TUBE STEEL AREA 3 |
| 1926 | SV3-CA03-MHW-CV2262 | CA03 TEMPORARY BRACING FOR LIFT INTO NI |
| 1927 | SV4-ECS-ERW-EL2296 | SV4 - ECS MAIN POWER DUCT BANKS / EAST PF ANNEX - PHASE 6 |
| 1928 | SV3-4031-SHW-EL5451 | FABRICATE AND INSTALL CABLE TRAY SUPPORTS ANNEX BLDG AREA 1 ELEV 100' PARTIAL OF BATTERY CHARGER ROOM 40308 W OF ROW LINE (G) |
| 1929 | SV3-VCS-SHW-ME2313 | INSTALLATION OF CONTAINMENT VCS RING HEADER HV AC SUPPORTS |
| 1930 | SV3-4031-SHW-EL5452 | FABRICATE AND INSTALL CABLE TRAY SUPPORTS ANNEX BLDG AREA 1 ELEV 100' PARTIAL OF BATTERY CHARGER ROOM 40310 E OF ROW LINE (G) |
| 1931 | SV3-VCS-SHW-ME2330 | INSTALLATION OF CONTAINMENT VCS HVAC SUPPORTS FOR AZIMUTH 75 - 120 |
| 1932 | SV3-VCS-SHW-ME2332 | INSTALLATION OF CONTAINMENT VCS HVAC SUPPORTS FOR AZIMUTH 150° - 170° |
| 1933 | SV3-PXS-PHW-ME3364 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-013 |
| 1934 | SV3-1000-TIW-855000 | CONTAINMENT VESSEL TENT FABRICATION |
| 1935 | SV3-2050-SHW-860258 | ELECTRICAL SUPPLEMENTAL STEEL TURBINE 3, EL 169'-0" AREA 0 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1936 | SV3-4031-SHW-EL5453 | FABRICATE AND INSTALL CABLE TRAY SUPPORTS ANNEX BLDG AREA 1 ELEV 100' BATTERY ROOM 40309 |
| 1937 | SV3-4031-SHW-EL5455 | FABRICATE AND INSTALL CABLE TRAY SUPPORTS ANNEX BLDG AREA 1 ELEV 100' BATTERY ROOM 40307 |
| 1938 | SV4-CA20-CAW-850102 | CA20 BASEMAT ATTACHMENT BRACKETS |
| 1939 | SV3-KQ22-KBW-860229 | MODULE KQ22 FABRICATION |
| 1940 | SV3-VCS-SHW-ME2333 | INSTALLATION OF CONTAINMENT VCS HVAC SUPPORTS FOR AZIMUTH 285 - 315DEG |
| 1941 | SV3-VCS-SHW-ME2334 | INSTALLATION OF CONTAINMENT VCS HV AC SUPPORTS FOR AZIMUTH 320-360 |
| 1942 | SV4-SWS-PHW-ME2363 | INSTALLATION OF SWS SUPPORTS FOR ISOMETRICS SV4-SWS-PLW-041, SV4-SWS-PLW-042, SV4-SWS-PLW-043, |
| 1943 | SV3-VCS-MDW-ME2378 | Fabrication and Installation of VCS HVAC Duct Ring Header |
| 1944 | SV3-VCS-MDW-ME2379 | FABRICATION AND INSTALLATION OF VCS DUCT ISO A1 |
| 1945 | SV3-VCS-MDW-ME2380 | FABRICATION AND INSTALLATION OF VCS DUCT ISO A2 |
| 1946 | SV3-VCS-MDW-ME2381 | FABRICATION AND INSTALLATION OF VCS DUCT ISO A3 |
| 1947 | SV3-VCS-MDW-ME2382 | FABRICATION AND INSTALLATION OF VCS DUCT ISO A4 |
| 1948 | SV3-CDS-PLW-ME2499 | INSTALLATION OF CDS PIPING |
| 1949 | SV3-MH20-EYW-860384 | 15 TON SECONDARY BRIDGE CRANE ELECTRICAL ASSEMBLY FOR THE TURBINE BUILDING IN ROOM 20600 |
| 1950 | SV3-ECS-ESW-EL7176 | INSTALL TURBINE BLDG ECS EQUIPMENT, MV SWITCHGEAR ECS-ES-4, ROOM 20501, ELEV 141'-3" |
| 1951 | SV3-PLS-JDW-EL7561 | INSTALL TURBINE BLDG PLS AND ASSOCIATED ZAS - 'EY' EQUIPMENT GROUP 2 IN ROOM 20513 ELEV 156'-0" |
| 1952 | SV4-ML05-MLW-ME7965 | INSTALL CA01 PENETRATION SV4-11305-ML-P02 |
| 1953 | SV4-CB65-S4W-CV2569 | INSTALLATION AND REMOVAL OF LIFTING BEAM/LUGS FOR CB65 |
| 1954 | SV3-PGS-P0W-ME2591 | FABRICATE AND INSTALL PGS SMALL BORE PIPING SHOWN ON ISOMETRIC DRAWING# SV3-PGS-PLW-836, 837, 862, 863, 888, 889, 914 AND 915 |
| 1955 | SV4-PGS-P0W-ME2593 | FABRICATE AND INSTALL PGS SMALL BORE PIPING SHOWN ON ISOMETRIC DRAWING# SV4-PGS-PLW- 851, 852, 877, 878, 903, 904, 929 AND 930 |
| 1956 | SV3-WWS-MTW-ME2643 | INSTALL UNIT 3 OIL/WATER SEPARATOR AREA SUMP SV3-WWS-MT-011. |
| 1957 | SV4-ES03-ESW-860939 | The installation of the Unit 4 Turbine Building Main Generator Circuit Breakers |
| 1958 | SV3-KB20-KBW-ME2687 | INTALLATION OF KB20 COMPONENTS |
| 1959 | SV3-WLS-P0W-ME2762 | KB16 - INSTALLATION OF VALVE ACTUATORS AT AIR OPERATED VALVES WLS-PL-V020A , WLS-PL-V020B & WLS-PL-V041 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1960 | SV3-KB16-KBW-ME2763 | KB16 - INSTALLATION OF LEVEL ELEMENT WLS-LT-021, THERMOCOUPLES WLS-JE-TE022 & WLS-JE-TE023, PRESSURE TRANSMITTERS WLS-PT-015 & WLS-PT-050 |
| 1961 | SV3-CAS-PHW-ME2781 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-CAS-PLW-733 |
| 1962 | SV3-2032-SHW-860940 | Electrical Cable Tray Support Installation in the Turbine Building, Elevation 100' |
| 1963 | SV3-VWS-P0W-ME2834 | INSTALLATION OF SMALL BORE KB14 PIPING (INCLUDING VALVE SV3-VWS-PL-V482) |
| 1964 | SV4-CA01-S4W-CV6502 | CA01-39 SUB MODULE INSTALLATION |
| 1965 | SV3-VWS-PHW-ME2835 | Fabrication/Installation of KB14/VWS Piping Supports |
| 1966 | SV3-WGS-THW-ME2845 | HYDROSTATIC TESTING OF MODULE KB14 WGS PIPING |
| 1967 | SV3-WWS-THW-ME2846 | HYDROSTATIC TESTING OF MODULE KB10 WWS PIPING |
| 1968 | SV4-PGS-PHW-ME2871 | INSTALLATION OF PGS PIPING SUPPORTS INCLUDED IN WORK PACKAGE SV4-PGS-P0W-ME2593 |
| 1969 | SV4-CAS-P0W-ME2874 | FABRICATE AND INSTALL CAS SMALL BORE PIPING SHOWN ON ISOMETRIC DRAWING# SV4-CAS-PLW-787, 788, 789, 794, 795, 796, 797 AND 798 |
| 1970 | SV3-DWS-THW-ME3038 | KB16 - HYDROSTATIC TESTING OF DWS PIPING |
| 1971 | SV3-WRS-THW-ME3039 | KB13 - HYDROSTATIC TESTING OF WRS PIPING |
| 1972 | SV4-PGS-PNW-ME3049 | INSTALL INSULATION OF UNIT 4 PGS PIPING INCLUDED IN WORK PACKAGE SV4-PGS-P0W-ME2593 |
| 1973 | SV4-4031-SSW-850000 | 100' ELEV STRUCTURAL STEEL, 1ST TIER COLUMNS, AREA 1 |
| 1974 | SV3-MH20-EYW-860942 | 220 TON TURBINE BRIDGE CRANE ELECTRICAL ASSEMBLY IN ROOM 20600 |
| 1975 | SV3-MH20-EYW-860943 | 220 TON TURBINE BRIDGE CRANE MAINLINE SYSTEM ASSEMBLY IN ROOM 20600 (CONDUCTOR BARS) |
| 1976 | SV3-EDS-DDW-EL7177 | INSTALL TURBINE BLDG EDS EQUIPMENT 125VDC PANELS ROOMS 20501, 20502, 20502 ELEB 141'-3" |
| 1977 | SV3-PLS-JDW-EL7562 | INSTALL TURBINE BLDG PLS AND ASSOCIATED ZAS "EY" EQUIPMENT GROUP 3 IN ROOM 20513 ELEV 156'-0" |
| 1978 | SV3-MH20-MHW-860366 | ASSEMBLY AND INSTALLATION OF 15 TON SECONDARY TURBINE CRANE |
| 1979 | SV3-1160-SSW-CV3059 | C8 CIRCULAR TRUNK SPL22, 23, 24 |
| 1980 | SV4-CA01-S4W-860305 | CA01-21 SUPPORTING LEG INSTALLATION |
| 1981 | SV4-CA01-S4W-CV6480 | CA01-33 SUB MODULE INSTALLATION |
| 1982 | SV3-EDS-DSW-EL3119 | INSTALL ANNEX BLDG NON CLASS 1E DC AND UPS SYSTEM LOAD GROUP 1 ROOM 40308 |
| 1983 | SV3-PLS-JDW-EL3150 | INSTALL ANNEX BLDG PLS EQUIPMENT (CABINETS AND MOTOR GENERATOR SETS) ROOM 40413 |
| 1984 | SV3-MSS-PHW-ME4668 | MSS PIPE SUPPORTS FOR PIPE PACKAGE SV3-MSS-P0W-ME4667 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 1985 | SV3-1130-C0W-850002 | REINFORCED CONCRETE INSIDE CONTAINMENT 87'-6" T0 95' REACTOR VESSEL AND REFUELING COMPARTMENTS |
| 1986 | SV4-1210-CRW-CV3156 | UNIT 4 NUCLEAR ISLAND AUX. BLDG INSTALLATION OF REINFORCING STEEL ON CA20 EXTERIOR WALL UP TO ELEV. 82'-6" (WALL PLACEMENT #0) |
| 1987 | SV3-WRS-THW-ME3224 | HYDROSTATIC TESTING OF WRS PIPING ON MODULE R104 |
| 1988 | SV4-CA20-S4W-CV3268 | INSTALLATION OF SUBMODULE CA20-07 |
| 1989 | SV4-WLS-PHW-ME3289 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWINGS WLS-PLW-33A, -260 |
| 1990 | SV4-WLS-PHW-ME3292 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING WLS-PLW-140 |
| 1991 | SV4-WLS-PHW-ME3294 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING WLS-PLW-190 |
| 1992 | SV4-WRS-P0W-ME3355 | INSTALLATION OF LARGE BORE WRS PIPING ( INCLUDES ISOMETRIC SV4-WRS-PLW-57G) |
| 1993 | SV3-PXS-P0W-ME3391 | ASME SECTION III – FABRICATION/INSTALLATION OF ISOMETRIC #SV3-PXS-PLW-290 (CA03 PIPING) |
| 1994 | SV3-PXS-P0W-ME3392 | ASME Section III - Fabrication/Installation of Isometric# SV3-PXS-PLW-293 (CA03 Piping) |
| 1995 | SV3-PXS-P0W-ME3397 | ASME SECTION III – FABRICATION/INSTALLATION OF ISOMETRIC #SV3-PXS-PLW-298 (CA03 PIPING) |
| 1996 | SV3-PXS-P0W-ME3398 | AME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC #SV3-PXS-PLW-220 (CA03 PIPING) |
| 1997 | SV0-SES-ERW-EL3558 | SV0-INSTALL CONDUITS IN SES DUCT BANK / SOUTH WEST OF UNIT 3 RADWASTE BUILDING (NXD618) |
| 1998 | SV0-0000-EGW-EL3572 | PERFORM INSTALLATION OF UNDERGROUND COMMODITIES (SV0 SITE STATION GROUNDING GRID) FOR GROUND GRID AREA L1200 |
| 1999 | SV3-PXS-P0W-ME3700 | FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-603 (CA03 PIPING) |
| 2000 | SV3-CAS-THW-ME3955 | HYDRO TESTING OF R155 MODULE CAS PIPING |
| 2001 | SV4-CA20-MHW-CV4000 | VERTICAL LIFTING FRAMES & BRACING CA20-SA1 SM 01 THRU 08. |
| 2002 | SV4-CA20-S5W-CV4002 | CA20-01 UNSATISFACTORY IRS/ N&DS/E&DCRS AND LOOS PARTS - STRUCTURAL |
| 2003 | SV4-CA20-S4W-CV4003 | CA20 WALL 2 SOUTH FACE -OLPs AND WELDED ATTACHMENTS INSTALLATION |
| 2004 | SV4-CA20-S5W-CV4006 | CA20-02 UNSAT IR# & N&D STRUCTURAL REPAIRS |
| 2005 | SV4-CA20-S4W-CV4008 | CA20-02 MAP OUT TEMPORARY ATTACHMENTS |
| 2006 | SV3-PLS-JDW-EL7560 | INSTALL TURBINE BLDG PLS AND ASSOCIATED ZAS EY EQUIPMENT GROUP 1 IN ROOM 20513 ELEV 156'-0" |
| 2007 | SV4-CA20-S5W-CV4014 | UNSAT IR# & N&D STRUCTURAL REPAIRS |
| 2008 | SV4-CA20-S4W-CV4015 | CA20 WALL 3 NORTH FACE - OLPs AND WELDED ATTACHMENTS INSTALLATION |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2009 | SV4-CA20-S4W-CV4020 | CA20-05 Map Out Temporary Attachments |
| 2010 | SV4-CA20-S4W-CV4023 | CA20 WALL 4 NORTH FACE - OLPs AND WELDED ATTACHMENTS INSTALLATION |
| 2011 | SV4-CA20-S5W-CV5762 | SUB-ASSEMBLY 4 BRACING |
| 2012 | SV4-CA20-S4W-CV4024 | CA20-06 Map Out Temporary Attachments |
| 2013 | SV4-CA20-S4W-CV4027 | CA20 WALL J1 EAST FACE - OLPs AND WELDED ATTACHMENTS INSTALLATION |
| 2014 | SV4-CA20-S4W-CV4028 | MAP OUT TEMPORARY ATTACHMENTS |
| 2015 | SV4-CA20-S5W-CV4030 | CA20-08 UNSAT IR# & N&D STRUCTUAL REPAIR |
| 2016 | SV4-2060-SSW-850112 | TB12 STAIRS AND HANDRAILS |
| 2017 | SV3-MS10-MEW-860242 | INSTALLATION OF SWITCHGEAR ROOM #1 AHUs - SV3-VTS-MS-02A & SV3-VTS-MS-02B |
| 2018 | SV4-CA20-S4W-CV4031 | CA20 WALL J1 WEST FACE - OLPs AND WELDED ATTACHMENTS INSTALLATION |
| 2019 | SV4-CA20-S4W-CV4032 | CA20-08 Map Out Temporary Attachments |
| 2020 | SV3-ECS-EBW-EL7603 | INSTALL TURBINE BLDG LOW VOLTAGE NON-SEGRAGATED BUS FOR CROSS-TIES BETWEEN SV3-ECS-EK-31/41 LOAD CENTERS ELEV 141'-3" ROOMS 20501, 20502 |
| 2021 | SV0-010-MYW-ME7171 | INSTALL OUTDOOR SAFETY SHOWERS AT BUILDING 315 |
| 2022 | SV3-1141-ERW-EL14150 | INSTALLATION OF CONDUIT ON SOUTHSIDE OF CA03 MODULE |
| 2023 | SV3-CAS-THW-ME4410 | HYDRO TESTING OF CAS PIPING IN MODULE R151 - ISO SV3-CAS-PLW-421, & 321 |
| 2024 | SV3-1208-SCW-CV4916 | COURSE 7 UNIT 3 SHIELD BUILDING |
| 2025 | SV3-1208-SCW-CV4917 | COURSE 8 UNIT 3 SHEILD BUILDING |
| 2026 | SV3-1208-SCW-CV4918 | COURSE 9 UNIT 3 SHIELD BUILDING |
| 2027 | SV3-1208-SCW-CV4919 | COURSE 10 UNIT 3 SHIELD BUILDING |
| 2028 | SV3-1208-SCW-CV4920 | COURSE 11 UNIT 3 SHIELD BUILDING |
| 2029 | SV3-1208-SCW-CV4922 | COURSE 13 UNIT 3 SHIELD BUILDING |
| 2030 | SV4-ML05-MLW-ME7651 | INSTALL CA01 ASME PROCESS PIPE PENETRATION SV4-11303-ML-P14 |
| 2031 | SV4-ML05-MLW-ME7658 | Install CA01 Penetration SV4-11502-ML-P01 |
| 2032 | SV4-CA01-S4W-CV8705 | CA01-28 Temporary Attachment Plate ID |
| 2033 | SV4-CA01-S4W-CV8706 | CA01-29 Temporary Attachment Plate ID |
| 2034 | SV3-1208-SCW-CV4923 | COURSE 14 UNIT 3 SHIELD BUILDING |
| 2035 | SV3-1208-SCW-CV4924 | COURSE 15 UNIT 3 SHIELD BUILDING |
| 2036 | SV3-2051-SHW-860261 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN UNIT 3 TURBINE BUILDING, BELOW ELEVATION 169'-0", AREA 1 FROM COLUMNS 14 TO 16, & P .2 TO R |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2037 | SV3-TDS-P0W-ME3529 | Installation And Fabrication of Turbine Island Vents, Drains, and Relief Systems (TDS) Piping |
| 2038 | SV3-2141-C0W-850003 | 1ST BAY 117' ELEV. FLOOR SLAB, POUR #3 |
| 2039 | SV4-WRS-PLW-ME5030 | CA20 LEAK CHASE TESTING PROCEDURE FOR CHANNELS CONNECTING TO THE SPENT FUEL POOL (FHS-MT-01) |
| 2040 | SV4-CA20-S4W-CV5291 | CA20 WALL J2 WEST FACE - OLPs AND WELDED ATTACHMENTS INSTALLATION |
| 2041 | SV4-CA20-S4W-CV5293 | CA20-11 MAP OUT TEMPORARY ATTACHMENTS |
| 2042 | SV4-CA20-S4W-CV5296 | CA20 WALL K2 EAST FACE - OLP'S AND WELDED ATTACHMENTS INSTALLATION |
| 2043 | SV4-1000-CEW-CV5122 | UNIT 4 NUCLEAR ISLAND EMBED PLATE FABRICATION |
| 2044 | SV4-CA20-S4W-CV5298 | CA20-12 MAP OUT TEMPORARY ATTACHMENTS |
| 2045 | SV4-CA20-S5W-CV5300 | CA20-13 UNSAT IR# & N&D STRUCTURAL REPAIRS |
| 2046 | SV4-CA20-S4W-CV5303 | CA20-13 MAP OUT TEMPORARY ATTACHMENTS |
| 2047 | SV3-EFS-EFW-EL7559 | INSTALL TURBINE BLDG. EFS - EF COMM./TELECOM. EQUIPMENT IN ROOM 20513 ELEV. 156'0" |
| 2048 | SV3-ECS-ESW-EL3135 | INSTALL ANNEX BLDG. AC SWITCHGEAR, ECS-ES-2, ROOM 40414 |
| 2049 | SV3-EDS-DSW-EL3123 | INSTALL ANNEX BUILDING NON CLASS 1E DC & UPS SYSTEM - LOAD GROUP 2, ROOM 40310 |
| 2050 | SV3-EDS-DDW-EL7557 | INSTALL TURBINE BUILDING EDS- "EA" DISTRIBUTION PNLS. EQUIPMENT IN ROOM 20308 ELEV. 100' |
| 2051 | SV3-2051-SHW-860260 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE UNIT 3 TURBINE BUILDING, BELOW ELEVATION 169'-0", AREA 1 FROM COLUMNS 13.1 TO 14, & P.2 TO R |
| 2052 | SV3-2057-SHW-860948 | Electrical Cable Tray Support Installation in the Turbine Building, Elevation 141'3", Area 7, Room 20500 |
| 2053 | SV3-2056-SHW-860946 | Electrical Cable Tray Support Installation in the Turbine Building, Elevation 141'3", Area 6, Room 20300 |
| 2054 | SV4-CA20-S4W-CV5306 | CA20 WALL L2 EAST FACE - OLPs AND WELDED ATTACHMENTS INSTALLATION |
| 2055 | SV3-ZVS-EPW-860945 | EXCITATION SYSTEM CABINETS INSTALLATION IN THE TURBINE BUILDING EQUIPMENT ROOM 20402 |
| 2056 | SV4-CA20-S4W-CV5308 | CA20-14 MAP OUT TEMPORARY ATTACHMENTS |
| 2057 | SV4-CA20-S5W-CV5310 | CA20-15 UNSATISFACTORY IRs/N&Ds/E&DCRs AND LOOSE PARTS - STRUCTURAL |
| 2058 | SV4-CA20-S4W-CV5311 | CA20 WALL L2 WEST FACE - OLPs AND WELDED ATTACHMENTS INSTALLATION |
| 2059 | SV4-CB28-CBW-850000 | CB28 MODULE INSTALLATION |
| 2060 | SV4-CA20-S4W-CV5313 | CA20-15 MAP OUT TEMPORARY ATTACHMENTS |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2061 | SV4-CA20-S5W-CV5315 | CA20-16 UNSATISFACTORY IRs/ N&Ds/ E&DCRs AND LOOSE PARTS -STRUCTURAL |
| 2062 | SV4-CA20-S4W-CV5316 | CA20 WALL N EAST FACE - OLP's AND WELDED ATTACHMENTS INSTALLATION |
| 2063 | SV4-CA20-S4W-CV5318 | CA20-16 MAP OUT TEMPORARY ATTACHMENTS |
| 2064 | SV4-CA20-S4W-CV5323 | CA20-17 MAP OUT TEMPORARY ATTACHMENTS |
| 2065 | SV4-WRS-P0W-ME5330 | FABRICATION/INSTALLATION OF SMALL BORE WRS LEAK CHASE PIPING INCLUDING SV4-WRS-PLW-80G, -80H, -80J, -80K |
| 2066 | SV4-WRS-P0W-ME5331 | FABRICATION/INSTALLATION OF SMALL BORE WRS LEAK CHASE PIPING INCLUDING SV4-WRS-PLW-80A, -80W, -86D, -865, -866, -867 |
| 2067 | SV4-WRS-P0W-ME5333 | FABRICATION/INSTALLATION OF SMALL BORE WRS LEAK CHASE PIPING INCLUDING SV4-WRS-PLW-80S, -86E, -801 |
| 2068 | SV4-WRS-P0W-ME5334 | FABRICATION/INSTALLATION OF SMALL BORE WRS LEAK CHASE PIPING INCLUDING SV4-WRS-PLW-80M, -80Z, -805, -806, -863, -864 |
| 2069 | SV4-WRS-P0W-ME5335 | FABRICATION/INSTALLATION OF SMALL BORE WRS LEAK CHASE PIPING INCLUDING SV4-WRS-PLW-80X, - 80Y, -802 |
| 2070 | SV4-WRS-P0W-ME5336 | Fabrication/Installation of Small Bore WRS Leak Chase Piping Including SV4-WRS-PLW-80R, -86B, -807 |
| 2071 | SV4-WRS-P0W-ME5338 | Fabrication/Installation of Small Bore WRS Leak Chase Piping Including SV4-WRS-PLW-803, -804, -860, -861, -80N, -80P |
| 2072 | SV3-CVS-P0W-ME3843 | FABRICATION/INSTALLATION OF PIPING FOR ISO SV3-CVS-PLW-65A AND SV3-CVS-PLW-65B |
| 2073 | SV3-PXS-PHW-ME4496 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-PXS-PLW-01L |
| 2074 | SV4-WRS-P0W-ME5339 | FABRICATION/INSTALLATION OF SMALL BORE WRS LEAK CHASE PIPING INCLUDING SV4-WRS-PLW-81E |
| 2075 | SV4-WRS-P0W-ME5342 | FABRICATION/INSTALLATION OF SMALL BORE WRS LEAK CHASE PIPING INCLUDING SV4-WRS-PLW-811, -812, -813, -814, -815)) |
| 2076 | SV4-WRS-P0W-ME5343 | FABRICATION/INSTALLATION OF SMALL BORE WRS LEAK CHASE PIPING INCLUDING SV4-WRS-PLW-816, -817, -818, -819 |
| 2077 | SV4-WRS-P0W-ME5344 | FABRICATION/INSTALLATION OF SMALL BORE WRS LEAK CHASE PIPING INCLUDING SV4-WRS-PLW-81EK, -81L, -81M |
| 2078 | SV4-WRS-P0W-ME5345 | Fabrication/Installation of Small Bore WRS Leak Chase Piping Including SV4-WRS-PLW-81N, -81P, -81Q, -81R, -81S |
| 2079 | SV4-WRS-P0W-ME5346 | FABRICATION/INSTALLATION OF SMALL BORE WRS LEAK CHASE PIPING INCLUDING SV4-WRS-PLW-81G, -81H, -81J) |
| 2080 | SV4-WRS-P0W-ME5347 | FABRICATION/INSTALLATION OF SMALL BORE WRS LEAK CHASE PIPING INCLUDING SV4-WRS-PLW-83G,-83J,-830,-831 |
| 2081 | SV4-WRS-P0W-ME5348 | Fabrication/Installation of Small Bore WRS Leak Chase Piping Including SV4-WRS-PLW-83B, -83E, -832, -835, -837 |
| 2082 | SV4-WRS-P0W-ME5350 | Fabrication/Installation of Small Bore WRS Leak Chase Piping Including SV4-WRS-PLW-83A, -83F, -839 |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2083 | SV4-WRS-P0W-ME5351 | FABRICATION/INSTALLATION OF SMALL BORE WRS LEAK CHASE PIPING INCLUDING SV4-WRS-PLW-83C, -83D, -83H, -83L |
| 2084 | SV4-WRS-P0W-ME5352 | Fabrication/Installation of Small Bore WRS Leak Chase Piping Including SV4-WRS-PLW-83Q, -83R |
| 2085 | SV4-WRS-P0W-ME5353 | FABRICATION AND INSTALLATION OF SMALL BORE WRS LEAK CHASE PIPING INCLUDING SV4-WRS-PLW-83K, - 83M, -833, -834, -838, -872, -873 |
| 2086 | SV4-WRS-P0W-ME5355 | Fabrication/Installation of Small Bore WRS Leak Chase Piping Including SV4-WRS-PLW-845, -846, -847 |
| 2087 | SV4-WRS-P0W-ME5356 | Fabrication/Installation of Small Bore WRS Leak Chase Piping Including SV4-WRS-PLW-84A, -84C, -849 |
| 2088 | SV4-WRS-P0W-ME5357 | Fabrication/Installation of Small Bore WRS Leak Chase Piping Including SV4-WRS-PLW-84M, -84N, -84P, -84Q |
| 2089 | SV4-WRS-P0W-ME5358 | Fabrication/Installation of Small Bore WRS Leak Chase Piping Including SV4-WRS-PLW-841, 842, 844 |
| 2090 | SV4-1210-ERW-EL1809 | Unit 4 Auxiliary Building - Grounding and sleeves for wall pours 23, 24, 25, 26, 27, 28, 29 & 32 |
| 2091 | SV4-SWS-CEW-CV5483 | UNIT 4, SWS TUNNEL, MECH / ELEC SLEEVE INSTALLATION |
| 2092 | SV3-KB14-KBW-ME4418 | SMALL BORE WGS PIPING FABRICATION/INSTALLATION |
| 2093 | SV4-CA20-S4W-CV5594 | CA20-18 Map Out Temporary Attachments |
| 2094 | SV4-CA20-S5W-CV5596 | CA20-19 UNSAT IR# & N&D STRUCTURAL REPAIRS |
| 2095 | SV4-CA20-S4W-CV5598 | INSTALLATION OF SUBMODULE CA20-19 |
| 2096 | SV4-CA20-S4W-CV5599 | CA20-19 Map Out Temporary Attachments |
| 2097 | SV4-WRS-P0W-ME5349 | Fabrication/Installation of Small Bore WRS Leak Chase Piping Including SV4-WRS-PLW-84B, -84E, -84R, -843, -848 |
| 2098 | SV4-CA20-S5W-CV5591 | CA20-18 UNSATISFACTORY IRs/N&Ds/E&DCRs AND LOOSE PARTS - STRUCTURAL |
| 2099 | SV4-CA20-S4W-CV4012 | CA20-03 MAP OUT TAMPORARY ATTACHMENTS |
| 2100 | SV4-CA20-S4W-CV4016 | CA20-04 MAP OUT TEMPORARY ATTACHMENTS |
| 2101 | SV4-WRS-P0W-ME5332 | Fabrication/Installation of Small Bore WRS Leak Chase Piping Including SV4-WRS-PLW-80B, -80C, -80T, -80U, -86F |
| 2102 | SV4-CA20-S5W-CV5601 | CA20 SUBMODULE 20 UNSAT IR AND N&D REPAIR |
| 2103 | SV4-CA20-S4W-CV5604 | CA20-20 MAP OUT TEMPORARY ATTACHMENTS |
| 2104 | SV3-ECS-EBW-EL7600 | INSTALL ANNEX BLDG. "LOW VOLTAGE" NON SEGREGATED BUS FOR CROSS-TIES BETWEEN SV3-ECS-EK-12/22 LOAD CENTERS, ELEV. 100, ROOM 40326 |
| 2105 | SV4-CA20-S5W-CV5606 | CA20-S1 UNSAT IR# & N&D STRUCTURAL REPAIRS |
| 2106 | SV4-CA20-S5W-CV5610 | CA20-22 UNSATISFACTORY IRs AND N&D REPAIRS, E&DCRs AND LOOSE PARTS - STUDS |
| 2107 | SV4-2141-C0W-850003 | Unit 4 Turbine Building First Bay 117'-6" Floor Slab Terminators |

# Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2108 | SV3-ECS-ESW-EL3145 | INSTALL ANNEX BLDG AC SWITCHGEAR, ECS-ES=1 ROOM 40413 |
| 2109 | SV3-PLS-JDW-EL3140 | INSTALL ANNEX BLDG PLS EQUIPMENT ROOM 40414 |
| 2110 | SV3-ECS-EBW-EL7599 | INSTALL ANNEX BLDG LOW VOLTAGE NON-SEGREGATED BUS FOR CROSS TIES BETWEEN SV3-ECS-EK-11/21 LOAD CENTERS ELEV 100 ROOM 40326 |
| 2111 | SV4-CA20-S4W-CV5614 | CA20-22 MAP OUT TEMPORARY ATTACHMENTS |
| 2112 | SV4-CA20-S5W-CV5616 | CA20-23 UNSAT IR# & N&D STRUCTURAL REPAIRS |
| 2113 | SV4-CA20-S4W-CV5619 | CA20-23 MAP OUT TEMPORARY ATTACHMENTS |
| 2114 | SV4-CA20-S4W-CV5624 | CA20-24 MAP OUT TEMPORARY ATTACHMENTS |
| 2115 | SV4-CA20-S4W-CV5629 | CA20-25 MAP OUT TEMPORARY ATTACHMENTS |
| 2116 | SV4-CA20-MHW-CV5732 | VERTICAL LIFTING FRAMES & BRACING CA20-SA2 SM 10 THRU 17 |
| 2117 | SV4-CA20-MHW-CV5733 | VERTICAL LIFTING FRAMES & BRACING CA20-SA3 SM 18 THRU 25 |
| 2118 | SV4-CA20-MHW-CV5734 | VERTICAL LIFTING FRAMES & BRACING CA20-SA4 SM 26 THRU 30, 71, 72, 73 |
| 2119 | SV4-CA20-S5W-CV5735 | CA20-26 UNSATISFACTORY IRs AND N&D REPAIRS, E&DCRs AND LOOSE PARTS - STUDS |
| 2120 | SV4-CA20-S5W-CV5736 | CA20-26 UNSAT IR# & N&D STRUCTURAL REPAIRS |
| 2121 | SV4-CA20-S4W-CV5739 | CA20-26 MAP OUT TEMPORARY ATTACHMENTS |
| 2122 | SV4-CA20-S5W-CV5741 | CA20-27 Unsat. IR# & N&D Structural Repairs |
| 2123 | SV4-CA20-S4W-CV5743 | INSTALLATION OF SUB MODULE CA20-27 |
| 2124 | SV4-CA20-S4W-CV5744 | CA20-27 MAP OUT TEMPORARY ATTACHMENTS |
| 2125 | SV3-CA20-CEW-850003 | FABRICATION OF CA20 OVERLAY PLATES |
| 2126 | SV4-2060-C0W-850003 | 170' ELEV. FLOOR SLAB, POUR # 3 |
| 2127 | SV3-1230-ERW-860254 | INSTALL CONDUIT PENETRATIONS FOR AUXILIARY BUILDING SHIELD WALL, FROM ELEVATION 100'-0 " - 117'-6" |
| 2128 | SV4-CB00-S8W-CV3831 | FINAL INSTALLATION OF CB MODULES 65 & 66 AT ELEVATION 71'-6" |
| 2129 | SV4-CA20-S5W-CV5745 | CA20-28 UNSATISFACTORY IRs AND N&D REPAIRS - STUDS |
| 2130 | SV4-CA20-S4W-CV5749 | CA20-28 MAP OUT TEMPORARY ATTACHMENTS |
| 2131 | SV4-CB31-CBW-850000 | CB31 MODULE INSTALLATION |
| 2132 | SV4-CB35-CBW-850000 | CB35 MODULE INSTALLATION |
| 2133 | SV3-CAS-P0W-860290 | CAS SMALL BORE TIE-IN CONNECTIONS FROM KB15 MODULE |
| 2134 | SV4-CA20-S4W-CV5754 | CA20-29 MAP OUT TEMPORARY ATTACHMENTS |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2135 | SV3-SES-EEW-EL7558 | INSTALL TURBINE BLDG. SES SECURITY EQUIPMENT CONTROL PNLS. & CONTROLLERS IN ROOM 20513 ELV. 156' 0" |
| 2136 | SV4-CA20-S5W-CV5755 | CA20-30 UNSATISFACTORY IRs/N&Ds/E&DCRs AND LOOS PARTS - STUDS |
| 2137 | SV4-CA20-S5W-CV5756 | CA20-30 Unsat IR# & N&D Structural Repairs |
| 2138 | SV4-CA20-S4W-CV5759 | CA20-30 MAP OUT TEMPORARY ATTACHMENTS |
| 2139 | SV3-CAS-P0W-ME3435 | FABRICATION/INSTALLATION OF PIPING FOR ISO SV3-CAS-PLW-893, SV3-CAS-PLW-895 |
| 2140 | SV4-CA20-S5W-CV5760 | CA20-71 UNSAT IR - STUDS |
| 2141 | SV0-DFS-C0W-850001 | DIESEL FUEL TRANSFER STATION, DFS-MS001 EQUIPMENT PAD |
| 2142 | SV4-CA20-S4W-CV5764 | CA20-71 MAP OUT TEMPORARY ATTACHMENTS |
| 2143 | SV4-CA20-S5W-CV5765 | CA20-72 UNSAT IR# & N&D STUD REPAIRS |
| 2144 | SV4-CA20-S4W-CV5768 | INSTALLATION OF SUBMODULES CA20-71, CA20-72, AND CA20-73 |
| 2145 | SV4-CA20-S4W-CV5769 | CA20-72 MAP OUT TEMPORARY ATTACHMENTS |
| 2146 | SV4-CA20-S5W-CV5770 | CA20-73 UNSAT IR STUDS |
| 2147 | SV4-CA20-S4W-CV5774 | CA20-73 MAP OUT TEMPORARY ATTACHMENTS |
| 2148 | SV3-1154-ERW-EL8974 | Fabrication and Installation of Conduit Supports for Area 4 on Ring 2 of the Containment Vessel at EL. 131'-9" to 170'-0". |
| 2149 | SV3-PXS-P0W-ME6162 | Fabrication and Installation of CA03 Large Bore Piping Shown on Isometric SV3-PXS-PLW-230 |
| 2150 | SV4-WLS-P0W-ME6237 | INSTALLATION OF SMALL BORE CA01 WLS EMBEDDED PIPING (INCLUDE ISOMETRICS SV4-WLS-PLW-562, 566, 573, 574, & 575) |
| 2151 | SV4-WLS-P0W-ME6238 | INSTALLATION PF S,A;; BPRE CA01 WLS EMBEDDED PIPING (INCLUDE ISOMETRICS SV4-WLS-PLW-564, -565, -570, -571, & -572) |
| 2152 | SV3-CA02-S4W-CV6272 | INSTALL CA02-05 PERMANENT WELDED ATTACHMENTS |
| 2153 | SV4-CA01-S5W-CV6357 | CA01-01 UNSATISFACTORY IRs/N&Ds/E&DCRs AND LOOSE PARTS-STRUCTURAL |
| 2154 | SV4-CA01-S5W-CV6361 | CA01-02 UNSAT IRs/N&Ds/E&DCRs/LOOSE PARTS -STRUCTURAL |
| 2155 | SV4-CA01-S5W-CV6365 | CA01-03 UNSAT IRS/N&DS/E&DCRS/LOOSE PARTS - STRUCTURAL |
| 2156 | SV4-CA01-S4W-CV6367 | SUBMODULE CA01-04 INSTALLATION |
| 2157 | SV4-CA01-S5W-CV6386 | CA01-08 UNSAT IRs/N&Ds/EDCRs/ LOOSE PARTS-STRUCTURA |
| 2158 | SV4-MSS-P0W-860356 | INSTALLATION AND FABRICATION OF MAIN STEAM SYSTEM(MSS) PIPING |
| 2159 | SV3-1130-C0W-850007 | REFUEL CAVITY FLOOR |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2160 | SV4-CA01-S4W-CV6532 | CA01 - OLP & WELDED ATTACHMENTS - ELV.. 94' - 96' |
| 2161 | SV4-2060-CSW-850013 | TB13 STAIRS AND HANDRAILS |
| 2162 | SV4-2050-C0W-850004 | 141'-3" ELEV. FLOOR SLAB, POUR # 4 |
| 2163 | SV3-ME01-PHW-860974 | CONDENSER B HEATER DRAIN PIPING SUPPORT |
| 2164 | SV3-EDS-EAW-EL3131 | INSTALL ANNES BLDG. EDS4-EA AND EDS4-DD DISTRUBUTION PANELS, ROOM 40414 |
| 2165 | SV4-CA01-S4W-CV6488 | CA01-35 Installation |
| 2166 | SV4-WLS-P0W-860376 | FABRICATION/INSTALLATION OF WLS PIPING (ISOMETRIC DRAWING SV4-WLS-PLW-170) |
| 2167 | SV4-CA01-S5W-861314 | CA01- Misc. Work, Misc. Unsat. IRs/N&Ds and E&DCRs |
| 2168 | SV3-PWS-P0W-861060 | INSTALLATION OF ANNEX BLDG POTABLE WATER SYSTEM PWS PIPING (ISO SV3-PWS-PLW-412 & -414) |
| 2169 | SV3-SES-EEW-EL6227 | INSTALL (SES) PLANT SECURITY SYSTEM EQUPIMENT FOR ANNEX COMPUTER ROOM "A" - 40410 ELEV. 118'-6" |
| 2170 | SV4-DWS-PHW-860938 | Fabrication/Installation of DWS Piping Supports (Isometric Drawings SV4-DWS-PLW-60D, -624 and -625 |
| 2171 | SV4-VWS-PHW-860963 | Fabrication/Installation of VWS Piping Supports (Isometric Drawings SV4-VWS-PLW-260, -384 and -389) |
| 2172 | SV4-VAS-P0W-861320 | INSTALLATION OF ISOMETRICS SV4-VAS-PLW-340 AND SV4-VAS-PLW-350 IN THE CA20 MODULE |
| 2173 | SV3-PXS-P0W-861165 | ASME SECTION III – FABRICATION/INSTALLATION OF PIPING FOR ISOMETRIC SV3-PXS-PLW-028 (LINE NUMBER L120) |
| 2174 | SV3-EDS1-EAW-EL6226 | INSTALL (EDS1) EA-LOW VOLTAGE DISTRIBUTION PNL EQUIPMENT FOR ANNEX COMPUTER ROOM "A"-ELEV. 118'-6" |
| 2175 | SV3-2050-SHW-860259 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE UNIT 3 TURBINE BUILDING, BELOW ELEVATION 169'-0" SOUTH OF COLUMN 13.1, & BETWEEN P.1 TO R |
| 2176 | SV3-CDS-PLW-ME2310 | INSTALLATION OF CDS PIPING |
| 2177 | SV3-2060-CSW-850013 | TB13 STAIRS AND HANDRAILS |
| 2178 | SV4-2050-C0W-850002 | 141'-3" ELEV. FLOOR SLAB, POUR #2 |
| 2179 | SV4-2050-C0W-850003 | 141'-3" ELEV. FLOOR SLAB, POUR #3 |
| 2180 | SV3-1130-C0W-850006 | IRWST Floor |
| 2181 | SV3-KQ22-KQW-ME1691 | KQ22 LOWER CVCS MODULE INSTALL |
| 2182 | SV4-CA01-S5W-860270 | CA01 REBAR FABRICATION, TORQUEING TO COUPLERS AND TESTING |
| 2183 | SV4-VAS-MDW-860209 | FABRICATE/INSTALL VAS DUCT AND SUPPORTS IN ROOM 12153 |
| 2184 | SV3-ML05-MLW-ME6086 | INSTALLATION OF ANNULUS WALL PENETRATIONS 100'0 TO 117'0 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2185 | SV4-WLS-P0W-860375 | FABRICATION/INSTALLATION OF WLS PIPING (INCLUDING ISOMETRIC SV4-WLS-PLW-161) |
| 2186 | SV3-KQ23-KQW-ME1692 | KQ23 UPPER CVCS MODULE INSTALL |
| 2187 | SV3-PXS-P0W-ME2961 | FABRICATION/INSTALLATION OF ISOMETRIC # SV3-PXS-PLW-019 ( |
| 2188 | SV3-PXS-P0W-ME3239 | FABRICATION/INSTALLATION OF ISOMETRIC # SV3-PXS-PLW-026 |
| 2189 | SV3-PXS-P0W-861011 | INSTALL ISOMETRIC SV3-PXS-PLW-938 LARGE BORE PIPING |
| 2190 | SV3-SFS-P0W-861167 | Install Isometric SV3-SFS-PLW-780 |
| 2191 | SV3-PXS-P0W-861016 | Install large bore piping for Isometric SV3-PXS-PLW-948 |
| 2192 | SV3-PXS-PHW-861018 | INSTALL ISOMETRIC SV3-PXS-PLW-935 LARGE BORE PIPE SUPPORTS |
| 2193 | SV3-1227-ERW-860442 | INSTALL DESIGN ROUTED CABLE TRAY & CABLE TRAY SUPPORTS IN SHIELD ANNULUS TUNNEL 82'-6" LEVEL |
| 2194 | SV3-1227-ERW-860443 | INSTALL DESIGN ROUTED SAFETY RELATED CONDUIT, BOXES & CONDUIT SUPPORTS IN SHIELD ANNULUS TUNNEL, 82¿-6¿ LEVEL |
| 2195 | SV3-PXS-P0W-861008 | Install large bore supports for Isometric SV3-PXS-PLW-935 |
| 2196 | SV3-PXS-P0W-861010 | Install large bore supports for Isometric SV3-PXS-PLW-937 |
| 2197 | SV3-PXS-PHW-881159 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-PXS-PLW-283 |
| 2198 | SV4-KQ11-KQW-860208 | INSTALL LEDGER ANGLES FOR KQ11 & PERFORM SEAL WELD FROM KQ11 TO CB65 |
| 2199 | SV3-4042-SAW-861026 | INSTALL HILTI GIRDER SYSTEM ANNEX BUILDING AREA 2 EL. 117'-6" |
| 2200 | SV3-1220-CPW-CV1074 | UNIT 3 INSTALLATION OF FLOOR PRECAST PANELS EL.82'-6" |
| 2201 | SV3-SFS-P0W-ME3651 | INSTALLATION OF LARGE BORE SFS PIPING (INCLUDES ISOMETRIC SV3-SFS-PLW-566) |
| 2202 | SV3-Q240-Q2W-861350 | COMPLETION OF MODULE Q240 |
| 2203 | SV4-MT71-C0W-850002 | WASTE WATER RETENTION BASIN BOTTOM SLAB, CENTER POUR |
| 2204 | SV4-4031-ERW-860381 | INSTALLATOIN OF EMBEDDED CONDUCT ANNEX BULIDING,AREA 1 ELEV.100'-0" |
| 2205 | SV4-2038-SHW-860264 | SUPPLEMENTAL STEEL INSTALLATION AREA 8 FROM COLS 13.05 TO 14 IN TURBINE 4 |
| 2206 | SV4-WLS-PHW-861335 | INSTALLATION OF WLS PIPE SUPPORTS FOR ISOMETRIC SV4-WLS-PLW-364 |
| 2207 | SV3-ME01-P0W-860980 | INSTALLATION OF CONDENSER B HEATER DRAIN PIPING |
| 2208 | SV4-WRS-P0W-861358 | INSTALLATION OF PIPING FOR ISOMETRICS SV4-WRS-PLW-660, -664 & -665 |
| 2209 | SV4-FWS-P0W-860897 | INSTALLATION AND FABRICATION OF MAIN AND STARTUP FEEDWATER SYSTEM (FWS) PIPING SUPPORT |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2210 | SV4-MT71-C0W-850004 | WASTE WATER RETENTION BASIN WALL POUR # 4 |
| 2211 | SV4-MSS-PHW-860359 | INSTALLATION AND FABRICATION OF MAIN STEAM SYSTEM (MSS) PIPING SUPPORT |
| 2212 | SV4-WRS-PHW-861359 | INSTALLATION OF PIPE SUPPORTS FOR ISOMETRICS SV4-WRS-PLW-660, 664 & 665 |
| 2213 | SV4-4033-SSW-850000 | STRUCTURAL STEEL, 1ST TIER COLUMNS, AREA 3 |
| 2214 | SV4-WLS-P0W-861339 | INSTALLATION OF WLS PIPING FOR ISOMETRICS SV4-WLS-PLW-445, 936 |
| 2215 | SV3-2051-SHW-860262 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE UNIT 3 TURBINE BUILDING, BELOW ELEV 169'-0" AREA 1 FROM COLUMNS 14 TO 16 & P.1 TO P.2 |
| 2216 | SV3-ML05-MLW-861324 | FABRICATION/INSTALLATION OF PIPE PENETRATIONS FOR ISO SV3-ML05-V2-317 |
| 2217 | SV3-RNS-PHW-861420 | FABRICATION/INSTALLATION OF SUPPORTS FOR ISO SV3-RNS-PLW-141 |
| 2218 | SV3-SFS-P0W-ME6692 | FABRICATION/INSTALLATION OF ISOMETIC SV3-SFS-PLW-789 (LINE NUMBERS SFS-PL-L038, -L052, -L140) |
| 2219 | SV3-PXS-P0W-861014 | INSTALL ISOMETRIC SV3-PXS-PLW-946 LARGE BORE PIPING |
| 2220 | SV3-PXS-P0W-ME2963 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC SV3-PXS-PLW-01B (LINE NUMBERS PXS-PL-L128A & L131A) |
| 2221 | SV3-PXS-PHW-ME5584 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-PXS-PLW-640 |
| 2222 | SV3-2054-SHW-860263 | CABLE TRAY SUPLEMENTAL STEEL, UNIT 3 TURBINE, BELOW EL 169'-0", AREA 4 NORTH OF 12.1, K.5-L.5 |
| 2223 | SV3-R219-ERW-861315 | INSTALLATION OF ELECTRICAL CABLE TRAY AND TRAY GROUNDING IN MODULE R219 |
| 2224 | SV4-CA01-S4W-861376 | CA01-GUIDE PIN INSTALL |
| 2225 | SV0-010-EWW-861550 | ITP ELECTRICAL ASSISTANCE FOR BUILDING 315 |
| 2226 | SV4-4042-SSW-850000 | 116'-10" ELEV FLOOR STRUCTURAL STEEL AREA 2 |
| 2227 | SV4-4052-SSW-850000 | 134'-7" ELEV FLOOR STRUCTURAL STEEL AREA 2 |
| 2228 | SV4-PXS-P0W-885600 | ASME III – FABRICATION/INSTALLATION OF CA03 SMALL BORE PIPE FOR ISOMETRICS SV4-PXS-PLW-293 & SV4-PXS-PLW-294 |
| 2229 | SV3-CWS-PLW-ME2507 | INSTALLATION OF CWS PIPING ISO'S 70X, 70Y, 70Z, 71D |
| 2230 | SV3-2030-SHW-860274 | ELECTRICAL CABLE TRAY SUPPORT INSTALLATION IN THE TURBINE BULIDING,ELEVATION 100",AREA 0,ROOM 20300(TRAPEZE |
| 2231 | SV4-CA01-S4W-CV6506 | CA01-40 SUM MODULE INSTALLATION |
| 2232 | SV4-4041-SSW-850000 | 116'-0" ELEV FLOOR STRUCTURAL STEEL, AREAS 1 |
| 2233 | SV3-DOS-PHW-861516 | INSTALL PIPE SUPPORTS(SPIDERS) ON THE DESIEL FUEL OIL LINES FROM THE DESIEL GENERATOR |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2234 | SV4-WLS-P0W-861507 | INSTALLATION OF PIPING FOR SV4-WLS-PLW-281 & -931 |
| 2235 | SV4-CAS-P0W-861510 | INSTALLATION OF PIPING FOR SV4-CAS-PLW-330 & -891 |
| 2236 | SV0-DFS-THW-861460 | HYDRO TEST THE DIESEL FUEL OFFLOADING SYSTEM (DFS) PIPING |
| 2237 | SV0-DFS-THW-861461 | PNEUMATIC TEST OFDIESEL FUEL OFFLOADING SYSTEM (DFS) PIPING |
| 2238 | SV4-WLS-P0W-861341 | INSTALLATION OF WLS PIPING FOR ISOMETRICS SV4-WLS-PLW-33A & 870 |
| 2239 | SV4-CA01-CAW-850000 | CA01 MODULE INSTALLATION |
| 2240 | SV4-CA20-S4W-CV5118 | Realignment of Unit 4 CA20 Single-Sided Walls |
| 2241 | SV4-WLS-P0W-861509 | INSTALLATION OF PIPING FOR SV4-WLS-PLW-93A & -990 |
| 2242 | SV4-VWS-PHW-861173 | FABRICATION/ INSTALLATION OF VWS PIPING SUPPORTS (ISOMETRIC DRAWINGS SV4-VWS-PLW-270, -484 AND -489 |
| 2243 | SV4-CA20-CAW-850101 | CA20 WATERTIGHT DOOR |
| 2244 | SV4-2100-SSW-850000 | First Bay, Bolt Qualification |
| 2245 | SV3-CVS-MLW-861034 | ASME SECTION III - INSTALLATION OF CONTAINMENT VESSEL PENETRATION SV3-CVS-PY-C01 (P05) |
| 2246 | SV3-RNS-PHW-861207 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-RNS-PLW-380 |
| 2247 | SV3-SGS-MLW-861043 | ASME SECTION III - INSTALLATION OF CONTAINMENT VESSEL PENETRATION SV3-SGS-PY-C05A (P44) |
| 2248 | SV4-PXS-P0W-861450 | ASME SECTION III – FABRICATION/INSTALLATION OF CA03 SMALL BORE PIPE FOR ISOMETRIC SV4-PXS-PLW-290 |
| 2249 | SV4-CA05-CAW-850000 | CA05 MODULE INSTALLATION |
| 2250 | SV4-PXS-P0W-885602 | ASME SECTION III – FABRICATION/INSTALLATION OF CA03 SMALL BORE PIPE FOR ISOMETRICS SV4-PXS-PLW-297 & SV4-PXS-PLW-298 |
| 2251 | SV4-WRS-P0W-861357 | INSTALLATION OF PIPING FOR ISOMETRICS SV4-WRS-PLW-59R & 59V |
| 2252 | SV4-ML05-MLW-861465 | INSTALLATION OF ASME CA03 PENETRATIONS SV4-11305-ML-P19 AND SV4-11305-ML-P20 |
| 2253 | SV4-PXS-PHW-885603 | FABRICATION/INSTALLATION OF CA03 PIPE SUPPORTS FOR ISOMETRICS SV4-PXS-PLW-781 & SV4-PXS- PLW-801 |
| 2254 | SV4-ML05-MLW-861463 | INSTALLATION OF ASME CA03 PENETRATION SV4-11305-ML-P16 |
| 2255 | SV4-PXS-PHW-885611 | FABRICATION/INSTALLATION OF CA03 PIPE SUPPORTS FOR ISOMETRICS SV4-PXS-PLW-295 & SV4-PXS- PLW-296 |
| 2256 | SV0-DFS-P0W-860237 | DFS PIPING FROM NEAR BUILDING 306 TO PAD 321 |
| 2257 | SV0-DFS-P0W-860238 | DFS FIBERCAST LEAK CONTAINMENT JACKET PIPING FROM NEAR BUILDING 306 TO PAD 321 |
| 2258 | SV4-SFS-P0W-861517 | ASME III – FABRICATION/INSTALLATION OF CA20 LARGE BORE PIPE FOR ISOMETRIC SV4-SFS-PLW-170 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2259 | SV4-PXS-PHW-885610 | ASME III – FABRICATION/INSTALLATION OF CA03 PIPE SUPPORTS FOR ISOMETRICS SV4-PXS-PLW-293 & SV4-PXS-PLW-294 |
| 2260 | SV3-WRS-MTW-861416 | INSTALLATION OF WRS-MT-02A/02B TANKS |
| 2261 | SV3-MH20-EYW-860385 | 15 TON SECONDARY BRIDGE CRANE MAINLINE STSTEM ASSEMBLY FOR THE TURBINE BUILDING IN ROOM 20600 (CONDUCTOR BARS) |
| 2262 | SV3-1210-CEW-CV1262 | UNIT 3 AUXILIARY BUILDING-EL. 66'6" EMBED PLATES FOR CONCRETE WALL PLACEMENTS #5, #21, #22, #23, & #24 |
| 2263 | SV3-1130-SSW-850001 | UNIT 3, Q2-23 BEAM SEAT FABRICATION |
| 2264 | SV3-PWS-P0W-ME4946 | INSTALLATION OF ANNEX POTABLE WATER SYSTEM (PWS) PIPING INCLUDING ISOMETRICS: SV3-PWS-PLW-104, -136, -196, THRU 198, -453 & -470 |
| 2265 | SV3-4030-AMW-850000 | 100' ELEV. MASONRY, BATTERY ROOMS |
| 2266 | SV3-WWS-P0W-861592 | FABRICATE AND INSTALL THE HDPE WASTE WATER SYSTEM (WWS) PIPING AROUND |
| 2267 | SV4-PXS-P0W-885593 | ASME III - FABRICATION/INSTALLATION OF CA03 SMALL BORE PIPE FOR ISOMETRICS SV4-PXS-PLW-781 & SV4-PXS-PLW-801 |
| 2268 | SV4-ML05-MLW-861464 | INSTALLATION OF ASME CA03 PENETRATIONS SV4-11305-ML-P14 AND SV4-11305-ML-P15 |
| 2269 | SV4-PXS-P0W-885596 | ASME III - FABRICATION/INSTALLATION OF CA03 LARGE BORE PIPE FOR ISOMETRICS SV4-PXS-PLW-220 & SV4-PXS-PLW-221 |
| 2270 | SV4-PXS-PHW-885604 | ASME III – FABRICATION/INSTALLATION OF CA03 PIPE SUPPORTS FOR ISOMETRICS SV4-PXS-PLW-791 & SV4-PXS-PLW-796 |
| 2271 | SV4-PXS-P0W-885595 | ASME III - FABRICATION/INSTALLATION OF CA03 LARGE BORE PIPE FOR ISOMETRICS SV4-PXS-PLW-223 & SV4-PXS-PLW-230 |
| 2272 | SV3-CA20-C0W-850003 | CA20 FLOOR SLABS 34-37 |
| 2273 | SV3-1130-SSW-850002 | Q2-33 BEAM SEAT FABRICATION |
| 2274 | SV3-4052-SAW-850004 | Unit 3, Annex Supplemental Steel 135'-3" Elev., Area 2 from CL 7-7.1 & H-F |
| 2275 | SV3-CH77-CHW-850000 | CH77 Structural Steel Installation |
| 2276 | SV3-PXS-P0W-ME3238 | ASME SECTION III- FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-025 (LINE NUMBER PXS-PL-L021B) |
| 2277 | SV4-1130-C0W-850011 | CONTAINMENT BUILDING-WEST CONCRETE-ELEV 83'-0" & 84'-6" TO 87'-6" |
| 2278 | SV3-PXS-P0W-861164 | ASME SECTION III – FABRICATION/INSTALLATION OF PIPING FOR ISOMETRIC SV3-PXS-PLW-01V (LINE NUMBERS L015A, L016A, L017A) |
| 2279 | SV4-ML05-MLW-861462 | INSTALLATION OF ASME CA03 PENETRATIONS SV4-11305-ML-P10& SV4-11305-ML-P11 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2280 | SV4-WRS-P0W-861649 | INSTALLATION OF PIPING FOR SV4-WRS-PLW-654 |
| 2281 | SV4-CA02-S4W-860168 | CA02-05 OLPs and Welded Attachments |
| 2282 | SV4-WWS-P0W-861552 | INSTALLATION AND FABRICATION OF WASTE WATER SYSTEM(WWS) PIPING FOR 140"SLAB 4 |
| 2283 | SV3-DWS-P0W-861096 | FABRICATION/INSTALLATION OF PIPING AND SUPPORTS FOR ISOME |
| 2284 | SV4-PXS-P0W-885594 | ASME III - FABRICATION/INSTALLATION OF CA03 SMALL BORE PIPE FOR ISOMETRICS SV4-PXS-PLW-791 & SV4-PXS-PLW-796 |
| 2285 | SV4-CA01-S4W-861189 | CA01-SA03 -ELEV 96' TO 107' OLPs AND WELDED ATTACHMENTS |
| 2286 | SV4-WLS-P0W-861522 | Fabrication/Installation of WLS Piping (Includes Isometric Drawings SV4-WLS-PLW-33K, -357 and -35F) |
| 2287 | SV4-WLS-PHW-861456 | INSTALLATION OF PIPE SUPPORTS FOR SV4-WLS-PLW-93A- & 990 |
| 2288 | SV4-WLS-PHW-861454 | INSTALLATION OF PIPE SUPPORTS FOR SV4-WLS-PLW-281 & -931 |
| 2289 | SV3-1124-SPW-850013 | SPL13 Main Support Beam Installation |
| 2290 | SV4-2050-C0W-850020 | 141'3" ELEVATION EQUIPMENT PADS AND CURBS |
| 2291 | SV3-PXS-PHW-ME4501 | Fabrication/Installation of Pipe Supports for Isometric Drawing SV3-PXS-PLW-01X |
| 2292 | SV4-PXS-PHW-885606 | ASME III – FABRICATION/INSTALLATION OF CA03 PIPE SUPPORTS FOR ISOMETRIC SV4-PXS-PLW-221 |
| 2293 | SV4-4051-SSW-850000 | 134'7" ELEV FLOOR STRUCTURAL STEEL AREAS 1 |
| 2294 | SV3-4051-SAW-850000 | Unit 3,Annex Supplemental Steel Area 1,Ei.135'3 CL 11.15-13 &E-I.1 |
| 2295 | SV3-4051-SAW-850003 | Supplementary Steel,EL.135',Area 1CL H/E & 9?10.05 |
| 2296 | SV3-4051-SAW-850002 | Supplementary Steel, El. 135'-3" ,Area 1 CL H/E & 10.5/11.09 |
| 2297 | SV3-2052-SHW-860953 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 141'-3", AREA 2, BETWEEN COLUMNS 16 TO 17, & BETWEEN P.2 TO R |
| 2298 | SV3-DWS-P0W-861099 | FABRICATION/ INSTALLATION OF PIPING AND SUPPORTS FOR ISOMETRIC SV3-DWS-PLW-723 ( LINE NUMBER L260) |
| 2299 | SV3-CAS-P0W-861438 | FABRICATION/ INSTALLATION OF PIPING AND SUPPORTS FOR ISOMETRIC SV3-CAS-PLW-845 ( LINE NUMBER L016) |
| 2300 | SV3-MS85-MEW-ME4799 | INSTALLATION OF THE LUBE OIL SYSTEM FLUSHING UNIT |
| 2301 | SV4-1211-ERW-861224 | INSTALL DESIGN ROUTED CONDUIT AND CONDUIT SUPPORTS IN BATTERY ROOM "B", ROOM 12104 EL. 66'-6" |
| 2302 | SV4-2038-SHW-860265 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION FROM COLUMNS 14 TO 16 IN AREA 8OF THE UNIT 4 TURBINE BUILDING, BELOW ELEVATION 119'-9" |
| 2303 | SV3-DWS-P0W-861098 | FABRICATION/ INSTALLATION OF PIPING AND SUPPORTS FOR ISOMETRIC SV3-DWS-PLW-720 (LINE NUMBER L260) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2304 | SV4-1120-CCW-CV4121 | UNIT 4 CONTAINMENT PLACEMENT, CURING & REPAIR OF CONCRETE FROM EL 80'0" TO 80'6" TO EL 83'-0" TO 84'-6" |
| 2305 | SV3-DWS-P0W-861097 | FABRICATION/ INSTALLATION OF PIPING AND SUPPORTS FOR ISOMETRIC SV3-DWS-PLW-721 (LINE NUMBER L260) |
| 2306 | SV3-RNS-PHW-861208 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-RNS-PLW-194 |
| 2307 | SV4-2020-MEW-860399 | CONDENSER C CONNECTION PIECE ASSEMBLY |
| 2308 | SV4-2020-MEW-860397 | CONDENSER A CONNECTION PIECE ASSEMBLY |
| 2309 | SV4-WLS-PHW-861365 | INSTALLATION OF PIPE SUPPORTS FOR ISOMETRICS SV4-WLS-PLW-33B, -33G, & -33H |
| 2310 | SV3-CAS-P0W-861432 | FABRICATION/ INSTALLATION OF PIPING AND SUPPORTS FOR ISOMETRIC SV3-CAS-PLW-724 (LINE NUMBERS L205 & L279) |
| 2311 | SV3-CAS-P0W-861437 | FABRICATION/ INSTALLATION OF PIPING AND SUPPORTS FOR ISOMETRIC SV3-CAS-PLW-843 (LINE NUMBER L239) |
| 2312 | SV4-MT71-C0W-850005 | WWS Basin Wall, Pour # 5 |
| 2313 | SV4-CWS-PHW-ME5469 | INSTALLATION OF PIPE SUPPORTS FOR WP SV4-CWS-P0W-ME5456 |
| 2314 | SV3-2053-SHW-860954 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 156'-0", AREA 3, BETWEEN COLUMNS 19 TO 20, BETWEEN L.1 TO R |
| 2315 | SV3-1150-ERW-861713 | FABRICATION AND INSTALLATION OF HYDROGEN IGNITER CONDUIT SUPPORTS ATTACHING TO THE CONTAINMENT VESSEL AT 175' TO 275' ELEVATION. |
| 2316 | SV3-2057-SHW-860955 | ELECTRICAL CABLW TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 156'-0", AREA 7, BETWEEN COLUMNS 19 & 20, & BETWEEN K.5 TO L.1 |
| 2317 | SV4-1000-C0W-850001 | CONCRETE UNDER CONTAINMENT VESSEL, 8BY |
| 2318 | SV4-2060-SPW-850012 | TB12 GRATING / DECKING |
| 2319 | SV3-PXS-P0W-ME3378 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-02L (LINE NUMBERS PXS-PLL021B, L025B, L026B, L127B) |
| 2320 | SV3-2070-C0W-850001 | Unit 3, Turbine Building, Roof Elevated Slab, Pour # 1 |
| 2321 | SV3-2070-C0W-850004 | UNIT 3 TURBINE BUILDING, ROOF ELEVATED SLAB, POUR # 4 |
| 2322 | SV3-DWS-P0W-861103 | FABRICATION/ INSTALLATION OF PIPING AND SUPPORTS FOR ISOMETRICS SV3-DWS-PLW-724 (LINE NUMBER L260/L521) |
| 2323 | SV3-DWS-P0W-861102 | FABRICATION/INSTALLATION OF PIPING AND SUPPORTS FOR ISOMETRIC SV3-DWS-PLW-72C ( LINE NUMBER L260) |
| 2324 | SV4-1220-CPW-CV5123 | UNIT 4 NUCLEAR ISLAND AUX BUILDING - INSTALLATION OF FLOOR PRE-CAST PANELS AT ELEV 82'-6" |

# Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2325 | SV3-SFS-P0W-ME8755 | FABRICATION/ INSTALLATION OF PIPING SUPPORTS FOR ISOMETRIC SV3-SFS-PLW-757 |
| 2326 | SV3-PXS-P0W-861751 | REMOVE MODULE Q223 VALVE OPERATORS |
| 2327 | SV3-1235-ERW-861444 | INSTALL CONDUIT SLEEVES FOR PENETRATIONS IN UNIT 3 AUX BUILDING FLOOR SLABS, EL 100'-0" AREA 5 RM. 12361 & AREA 6 RM. 12372 |
| 2328 | SV4-CA02-S4W-860170 | CA02- BASEMAT CONNECTION PLATES |
| 2329 | SV3-4043-SPW-850000 | 115'-8" ELEVATION. DECKING AND GRATING, AREA 3 |
| 2330 | SV3-2050-SUW-850513 | 156' ELEV, WALL STEEL, RM 20513 |
| 2331 | SV4-4052-SAW-850002 | SUPPLEMENTAL STEEL 135'-3" ELEV., AREA 2 FROM CL 4.1-7 & G-F |
| 2332 | SV3-1225-CSW-850100 | S04 STAIR TOWER FROM ELEV. 66'-6" TO 135'-3" |
| 2333 | SV4-4052-SAW-850004 | UNIT 4, ANNEX SUPPLEMENTAL STEEL 135'-3" ELEV., AREA 2 FROM CL 7-7.1 & H-F |
| 2334 | SV4-WWS-P0W-861593 | FABRICATE AND INSTALL THE HDPE WASTE WATER SYSTEM (WWS) PIPING AROUND THE UNIT 4 WASTER WATER RETENTION BASIN |
| 2335 | SV4-FPS-PHW-860896 | INSTALLATION OF FPS PIPING SUPPORTS ELEVATION 100' |
| 2336 | SV3-Q233-Q2W-861062 | INSTALLATION OF MECHANICAL MODULE 1124-Q2-33 |
| 2337 | SV3-2043-SHW-861332 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 120'-6", AREA 3, COLUMNS 18 TO 19 & P.1 TO P.2 |
| 2338 | SV3-1242-SSW-850000 | Auxiliary Building Structural Steel from Elev. 100'-0' to 117'-6", Area 2 |
| 2339 | SV4-4052-SAW-850005 | SUPPLEMENTAL STEEL 135'-3" ELEV. ANNEX BUILDING, AREA 2 FROM CL 7.1-9 & G-H |
| 2340 | SV4-WRS-THW-861642 | HYDROSTASTIC TESTING FOR WRS IN ANNEX BUILDING |
| 2341 | SV3-CAS-P0W-861434 | FABRICATION/ INSTALLATION OF PIPING AND SUPPORTS FOR ISOMETRIC SV3-CAS-PLW-840 (LINE NUMBERS L016 & L240) |
| 2342 | SV3-RNS-PHW-861488 | FABRICATION/IINSTALLATION OF RNS LARGE BORE PIPE SUPPORTS FOR ISO RNS-PLW-172 |
| 2343 | SV3-RNS-P0W-861490 | FABRICATION/INSTALLATION OF RNS LARGE BORE PIPE FOR ISO SV3-RNS-PLW-177 |
| 2344 | SV3-PXS-PHW-ME3366 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-015 |
| 2345 | SV3-0150-ERW-EL4954 | CONDUIT AND EQUIPMENT FOR TRANSFORMER AREA NORTH OF TURBINE BUILDING |
| 2346 | SV4-ML05-MLW-861468 | INSTALLATION OF CA03PENETRATION SV4-11305-ML-P21 |
| 2347 | SV4-ML05-MLW-861467 | INSTALLATION OF CA03 PENETRATION SV4-11305-ML-P09 |
| 2348 | SV4-ML05-MLW-861466 | INSTALLATION OF CA03 PENETRATION SV4-11305-ML-P03 |
| 2349 | SV4-WRS-P0W-861449 | SV4-WRS-P0W-861449 |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2350 | SV4-4051-SAW-850002 | SUPPLEMENTAL STEEL, EL.135'-3", AREA 1 CL H/E & 10.5/11.09 |
| 2351 | SV3-4052-SAW-850007 | SUPPLEMENTAL STEEL, EL.135'-3", AREA 1 CL H/E & 10.5/11.09 |
| 2352 | SV4-R155-ERW-861346 | U4 MODULE R155 ELECTRICAL CABLE TRAY AND TRAY GROUNDING ISTALLATION |
| 2353 | SV4-R161-ERW-861348 | U4 MODULE R161 ELECTRICAL CABLE TRAY AND TRAY GROUNDING INSTALLATION |
| 2354 | SV4-R104-ERW-861349 | U4 MODULE R104 ELECTRICAL CABLE TRAY AND TRAY GROUNDING INTALLATION |
| 2355 | SV4-PXS-PHW-885612 | ASME III - FABRICATION/INSTALLATION OF CA03 PIPE SUPPORTS FOR ISOMETRICS SV4-PXS-PLW-297 & SV4-PXS-PLW-298 |
| 2356 | SV3-DWS-P0W-861553 | INSTALLATION OF ANNEX BLDG DWS PIPING (ISO-SV3-DWS-PLW-199, 200 & 202) |
| 2357 | SV3-WWS-THW-861594 | HYDRO TEST UNIT 3 WASTE WATER SYSTEM (WWS) HDPE PIPING |
| 2358 | SV3-2046-SHW-860985 | TURBINE BUILDING, AREA 6, EL. 120'-6" CABLE TRAY SUPPLEMENTAL STEEL COLUMNS 17 TO 18, & I.2 TO J.15 |
| 2359 | SV4-4030-C0W-850006 | 100'-0" Elev Wall, Wall 6 |
| 2360 | SV4-WLS-P0W-ME6239 | INSTALLATION OF SMALL BORE CA01 WLS EMBEDDED PIPING (INCLUDE ISOMETRICS SV4-WLS-PLW-576, -577, -578, & -579) |
| 2361 | SV4-SFS-PHW-885608 | FABRICATION/INSTALLATION OF CA03 PIPE SUPPORTS FOR ISOMETRIC SV4-SFS-PLW-604 |
| 2362 | SV4-PXS-PHW-885609 | FABRICATION/INSTALLATION OF CA03 PIPE SUPPORTS FOR ISOMETRIC SV4-PXS-PLW-299 |
| 2363 | SV4-PXS-PHW-885607 | FABRICATION/INSTALLATION OF CA03 PIPE SUPPORTS FOR ISOMETRIC SV4-PXS-PLW-603 |
| 2364 | SV4-SFS-P0W-885598 | FABRICATION/INSTALLATION OF CA03 SMALL BORE PIPE FOR ISOMETRIC SV4-SFS-PLW-604 |
| 2365 | SV4-PXS-P0W-885599 | FABRICATION/INSTALLATION OF CA03 SMALL BORE PIPE FOR ISOMETRIC SV4-PXS-PLW-299 |
| 2366 | SV3-PXS-P0W-ME3381 | ASME SECTION III – FABRICATION/INSTALLATION OF ISOMETRIC #SV3-PXS-PLW-02Z (LINE NUMBERS PXS-PL-L113B & L129B) |
| 2367 | SV3-PXS-P0W-ME3372 | ASME SECTION III – FABRICATION/INSTALLATION OF ISOMETRIC #SV3-PXS-PLW-02A (LINE NUMBERS PXS-PL-L128B, L131B, & L132B) |
| 2368 | SV3-4031-ERW-861318 | INSTALLATION OF SCHEDULED CONDUIT IN ROOM 40309, ANNEX BUILDING, AREA 1, ELEVATION 100'-0" |
| 2369 | SV4-4042-SAW-850001 | UNIT 4, ANNEX SUPPLEMENTAL STEEL, AREA 2, 117'-6", CL 4.1 - 6 |
| 2370 | SV4-WLS-PHW-861453 | FABRICATION/INSTALLATION OF WLS PIPING SUPPORTS (ISOMETRICS DRAWINGS SV4-WLS-PLW-265 AND -275) |
| 2371 | SV4-WLS-P0W-861520 | INSTALLATION OF PIPING FOR SV4-WLS-PLW-35 & -359 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2372 | SV4-CA01-CCW-850000 | CA01 MODULE GUIDE PINS |
| 2373 | SV3-RNS-PHW-861481 | FABRICATION/INSTALLATION OF RNS LARGE BORE PIPE SUPPORTS FOR ISO SV3-RNS-PLW-17C |
| 2374 | SV4-REFDOC-RW4-850000 | REINFORCED CONCRETE FOREMAN'S BOOK |
| 2375 | SV3-2070-C0W-850006 | TURBINE ROOF ELEV. SLAB, POUR #6 |
| 2376 | SV4-WLS-PHW-861340 | INSTALLATION OF WLS PIPE SUPPORTS FOR ISOMETRICS SV4-WLS-PLW-445, 936, 93C & 940 |
| 2377 | SV4-CA20-C0W-850002 | CA20-66 FLOOR |
| 2378 | SV3-2047-SHW-861708 | ELECTRICAL CABLE TRAY TRAPEZE SUPPORTS FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 120'6", AREA 7 |
| 2379 | SV3-2060-X4W-850001 | UNIT 3, TURBINE DECK SURVEY MARKERS INSTALLATION |
| 2380 | SV3-VWS-P0W-860833 | INSTALL TURBINE BUILDING LARGE BORE VWS PIPING (ISOMETRICS SV3-VWS-PLW-107, 108, 20AA, 20AB & 206) |
| 2381 | SV3-2060-X4W-850000 | UNIT 3, TURBINE DECK SURVEY MARKERS INSTALLATION |
| 2382 | SV4-1210-CCW-CV3157 | UNIT 4 AUX BUILDING WEDGE AND N-LINE (WALL PLACEMENT #0) CONCRETE PLACEMENT FROM 66'-6" TO 82'-6" |
| 2383 | SV4-CAS-PHW-861457 | INSTALLATION OF PIPE SUPPORTS FOR SV4-CAS-PLW-330 & -891 |
| 2384 | SV4-4041-SAW-850001 | ANNEX SUPPLEMENTAL STEEL, AREA 2, 117'-6", CL 9-10.5 |
| 2385 | SV3-FWS-PHW-ME3826 | INSTALLATION AND FABRICATION OF FEED WATER SYSTEM (FWS) |
| 2386 | SV3-2043-SHW-861608 | ELECTRICAL CABLE TRAY TRAPEZE SUPPORTS FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 120'6", AREA 3 |
| 2387 | SV3-RMS-JDW-EL6225 | INSTALL (RMS) RADIATION MONITORING SYSTEM EQUIPMENT FOR ANNEX COMPUTER ROOM "A" -40410 ELEV. 118'-6" |
| 2388 | SV4-ME01-PHW-861724 | UNIT 4 CONDENSER A: INSTALLATION OF WATER CURTAIN SPRAY PIPING SUPPORTS |
| 2389 | SV4-MT71-C0W-850007 | Waste Water Retention Basin Wall Pour # 7 |
| 2390 | SV4-4052-SAW-850006 | UNIT 4, ANNEX SUPPLEMENTAL STEEL 135'-3", ELEV., AREA 2 FROM CL 7.1-9 & G-F |
| 2391 | SV4-ME01-PHW-861726 | UNIT 4 CONDENSER C: INSTALLATION OF WATER CURTAIN SPRAY PIPING SUPPORT |
| 2392 | SV4-WLS-PHW-861546 | INSTALLATION OF PIPE SUPPORTS FOR SV4-WLS-PLW-261 & -267 |
| 2393 | SV3-PLS-JDW-EL6229 | INSTALL (PLS) PLANT CONTROL SYSTEM EQUIPMENT FOR ANNEX COMPUTER ROOM "B" -40411, ELEV. 118'6" |
| 2394 | SV3-4031-ERW-861244 | INSTALL CABLE TRAY IN RMS 40307-40310 ANNEX BLDG. AREA 1, ELEV. 100' (WP4) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2395 | SV3-4031-ERW-861241 | INSTALL CABLE TRAY IN RMS 40307-40310 ANNEX BLDG. AREA 1, ELEV. 100' (WP1) |
| 2396 | SV3-4050-EGW-861863 | INSTALLATION OF EGS GROUNDING FOR THE ANNEX BUILDING, AREAS 1, 2 & 3 ELEV.135'-3"- BETWEEN COLUMN LINES 2/13 |
| 2397 | SV3-EDS3-DBW-861178 | INSTALLATION OF BATTERIES & ASSOCIATED HARDWARE FOR "EDS3" 125V NON-CLASS 1E DC & UPS SYSTEM (GROUP I) IN ANNEX BLDG. ROOM 40307 |
| 2398 | SV3-EDS2-DBW-861177 | INSTALLATION OF BATTERIES & ASSOCIATED HARDWARE FOR "EDS2" 125V NON-CLASS 1E DC & UPS SYSTEM (GROUP II) IN ANNEX BLDG. ROOM 40307 |
| 2399 | SV4-CAS-P0W-861564 | FABRICATION/INSTALLATION OF CAS PIPING SHOWN ON ISOMETRIC DRAWINGS SV4-CAS-PLW-326, -327 & -360 |
| 2400 | SV4-WLS-P0W-861558 | FABRICATION/INSTALLATION OF WLS PIPING SHOWN ON ISOMETRIC DRAWING SV4-WLS-PLW-961 |
| 2401 | SV3-4031-ERW-861243 | INSTALL CABLE TRAY IN ROOMS 40307- 40310 ANNEX BLDG. AREA 1 , ELVE. 100' (WP3) |
| 2402 | SV4-4041-SAW-850002 | UNIT 4 - ANNEX SSUPPLEMENTARY STEEL MODULAR ASSEMBLY), ELEV. 117'-6", AREA 1, CL 10.05 TO CL 11.09 |
| 2403 | SV3-2039-SHW-861793 | ELECTRICAL CABLE TRAY SUPPORT INSTALLATION IN THE TURBINE BUILDING, ELEVATION 100', AREA 9, ROOM 20300 (TRAPEZE & VF) |
| 2404 | SV3-1150-EGW-861819 | INSTALL GROUNDING IN CONTAINMENT & SHEILD WALLS FROM ELEV. 117'-6" - 135'-3" EXCLUDING AREAS WHERE SHIELD WALL & AUXILIARY BUILDING MEET |
| 2405 | SV4-KB13-KBW-861735 | MECHANICAL MODULE KB13 STRUCTURAL FABRICATION |
| 2406 | SV4-CAS-PHW-861458 | INSTALLATION OF PIPE SUPPORTS FOR SV4-CAS-PLW-33A & -895 |
| 2407 | SV4-1110-ERW-861804 | FABRICATION & INSTALLATION OF DESIGN CONDUIT SUPPORTS IN ROOM 11104 |
| 2408 | SV4-1130-EGW-861818 | INSTALL GROUNDIN IN CONTAINMENT & SHIELD WALLS FROM ELEV. 100'-0" - 117'-6" EXCLUDING AREAS WHERE SHIELD WALL & AUXILIARY BUILDING MEET |
| 2409 | SV4-SDS-THW-861643 | HYDROSTATIC TESTING FOR SDS IN ANNEX BUILDING |
| 2410 | SV4-ME01-PHW-861725 | UNIT 4 CONDENSER B: INSTALLATION OF WATER CURTAIN SPRAY PIPING SUPPORTS |
| 2411 | SV3-2070-C0W-850003 | UNIT 3, TURBINE BUILDING, ROOF ELEVATED SLAB POUR #3 |
| 2412 | SV3-2030-SUW-850308 | 100' ELEV., WALL STEEL, ROOM 20308 |
| 2413 | SV3-DDS-JDW-EL6228 | INSTALL (DDS) DATA DISPLAY AND PROCESSING SYSTEM EQUIPMENT FOR ANNEX COMPUTER ROOM "B" -40411, ELEV. 118' 6" |
| 2414 | SV3-RNS-PHW-881161 | Fabrication/Installation of Pipe Supports for Isometric Drawing SV3-RNS-PLW-191 |
| 2415 | SV4-0000-C0W-850008 | TRANSFORMER FOUNDATION WALL POUR #8 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2416 | SV3-4043-SPW-850001 | UNIT 3 - ANNEX, 126' - 3" ELEV., DECKING INSTALLATION |
| 2417 | SV3-1240-ERW-861046 | INSTALL CONDUIT PENETRATIONS FOR AUXILIARY BUILDING SHIELD WALL, FROM ELEVATION 117' - 6" - 135' - 3" |
| 2418 | SV4-CA01-S5W-CV6394 | CA01-10 UNSAT IRs / N&DS / E&DCRs / LOOSE PARTS - STRUCTURAL |
| 2419 | SV3-1134-SPW-850009 | SPL09 INSTALLATION |
| 2420 | SV0-DFS-C0W-850003 | DIESEL FUEL TRANSFER STATION, DFS-MS003 EQUIPMENT PAD |
| 2421 | SV4-2060-SSW-850000 | TB-12 THRU -16 STRUCTURAL STEEL REWORK / REPAIR |
| 2422 | SV4-2060-C0W-850006 | 170' ELEV. FLOOR SLAB, POUR # 6 |
| 2423 | SV3-ECS-EKW-EL7174 | INSTALL TURBINE BLDG ECS EQUIPMENT LV LOAD CENTER ECS-EK-41, ROOM 20501 ELEV 141'-3" |
| 2424 | SV3-4031-SHW-EL5450 | FABRICATE AND INSTALL CABLE TRAY SUPPORTS ANNEX BLDG AREA 1, ELEV 100' PARTIAL OF BATTERY CHARGER ROOM 40310 W OF ROW LINE G |
| 2425 | SV3-ECS-EKW-EL7180 | INSTALL TURBINE BLDG ECS EQUIPMENT LV LOAD CENTER ECS-EK-31 ROOM 20502 ELEV 141'-3" |
| 2426 | SV0-ZRS-C0W-850004 | COMMUNICATIONS SUPPORT CENTER, ZRS-MS004 EQUIPMENT PAD |
| 2427 | SV4-CA01-S5W-CV6414 | CA01-15 UNSAT IRs/N&DS/E&DCRs/LOOSE PARTS - STRUCTURAL |
| 2428 | SV4-0000-C0W-850006 | TRANSFORMER FOUNDATION WALL POUR #6 |
| 2429 | SV3-EDS-DSW-EL3120 | INSTALL ANNEX BLDG NON CLASS 1E DC AND UPS SYSTEM - LOAD GROUP 3, ROOM 40308 |
| 2430 | SV3-PXS-PHW-ME3789 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-02N |
| 2431 | SV4-CA01-S5W-CV6466 | CA01-29 UNSAT IRs / N&Ds / E&DCRs / LOOSE PARTS - STRUCTURAL |
| 2432 | SV4-0000-C0W-850005 | TRANSFORMER FOUNDATION WALL POUR #5 |
| 2433 | SV4-1000-C0W-850003 | UNDER CONTAINMENT VESSEL INNER 10.2 CONCRETE PLACEMENT |
| 2434 | SV3-ECS-EBW-EL7602 | INSTALL ANNEX BLDG LOW VOLTAGE NON-SEGREGATED BUS FOR CROSS TIES BETWEEN SV3-ECS-EK-14/24 LOAD CENTERS ELEV 100 ROOM 40326 |
| 2435 | SV3-ECS-EBW-EL7601 | INSTALL ANNEX BLDG LOW VOLTAGE NON-SEGREGATED BUS FOR CROSS TIES BETWEEN SV3-ECS-EK-13/23 LOAD CENTERS ELEV 100 ROOM 40326 |
| 2436 | SV4-0000-C0W-850022 | TRANSFORMER FOUNDATION WALL POUR #22 |
| 2437 | SV4-CA05-CRW-CV5200 | UNIT 4 CA05 WELDABLE COUPLER REINFORCEMENT |
| 2438 | SV0-4000-MUW-850000 | MASONRY MOCK-UP |
| 2439 | SV4-CA01-S5W-CV6430 | CA01-19 UNSATISFACTORY IRs/N&Ds/ E&DCRs AND LOOSE PARTS -STRUCTURAL |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2440 | SV4-CA01-S4W-CV6452 | SUBMODULE CA01-25, CA01-47 AND CA01-48 INSTALLATION |
| 2441 | SV4-CA01-S5W-CV6536 | SA4 LEAK CHASE FABRICATION |
| 2442 | SV4-CA01-S4W-CV6571 | U4-CA01- LIFTING FRAMES AND BRACING SUBMODULES 01, 02, 03, 20 THRU 24, & 35 |
| 2443 | SV4-CA01-S4W-CV6572 | U4-CA01 LIFTING FRAMES AND BRACING SUBMODULES 04, 11, 12, 17, THRU 19, 25, 47 & 48 |
| 2444 | SV4-CA01-S4W-CV6573 | U4-CA01 LIFTING FRAMES AND BRACING SUBMODULES 05 THRU 10 |
| 2445 | SV4-CA01-S4W-CV6575 | U4-CA01 LIFTING FRAMES AND BRACING SUBMODULES 13 THRU 16, 32, 33, 36, & 39 |
| 2446 | SV3-MH20-MHW-860956 | ASSEMBLY AND INSTALLATION OF 220 T TURBINE CRANE |
| 2447 | SV3-CA20-EGW-860291 | INSTALL GROUND CABLE FOR NON ELECTRICAL COMPONENTS SUCH AS CA20 TANKS AND HEAT EXCHANGERS, ELEVATION 100'-0" TO 107'-0" |
| 2448 | SV3-1213-ERW-EL3166 | AUXILARY BUILDING UNIT 3, EL 66'-6", AREA 3, FABRICATE AND INSTALL DESIGNED TRAY AND CONDUIT SUPPORTS |
| 2449 | SV4-CA20-S4W-CV6878 | CA20-47 TEMPORARY ATTACHMENTS - FLOOR & LEDGER ANGLES FOR CA20-47, 48, 49, 50. |
| 2450 | SV4-CA20-S4W-CV6879 | INSTALLATION OF CA20 SA3 FLOOR (SUBMODULES 47, 48, 49, 50)) |
| 2451 | SV4-CA20-S4W-CV6882 | CA20-48 Temporary Attachments |
| 2452 | SV3-ZAS-ERW-EL3254 | INSTALL CABLE TRAY & RACEWAY AUX TRANSFORMER ZAS-ET-4A IN TRANSFORMER AREA NORTH OF TURBINE BLDG |
| 2453 | SV4-CA20-S4W-CV6886 | CA20-49 Floor Temporary Attachments |
| 2454 | SV3-ZAS-ERW-EL3255 | INSTALL CABLE TRAY & RACEWAY AUX TRANSFORMER ZAS-ET-4B IN TRANSFORMER AREA NORTH OF TURBINE BLDG |
| 2455 | SV4-CA20-S4W-CV6890 | CA20-50 Temporary Attachments |
| 2456 | SV4-CA20-S4W-CV6956 | CA20-66 Temporary Attachments |
| 2457 | SV4-CA20-S4W-CV6957 | INSTALLATION OF CA20 SA4 FLOOR (SUBMODULES CA20-66) |
| 2458 | SV4-CA20-S5W-CV6973 | CA20 Rebar Fabrication, Torqueing and Testing |
| 2459 | SV4-2060-SPW-850013 | TB13 GRATING/DECKING |
| 2460 | SV4-CA20-S4W-CV6981 | SV4-CA20 POST WELDING SURVEY DATA/VERIFICATIONS |
| 2461 | SV4-CA05-S4W-CV7025 | CA05-01 Temporary Wal lAttachments |
| 2462 | SV4-CA05-S4W-CV7027 | CA05-03 Temporary Attachments |
| 2463 | SV4-CA05-S4W-CV7029 | CA05-05 Temporary Attachments |
| 2464 | SV4-CA05-S4W-CV7030 | CA05-06 Temporary Attachments |
| 2465 | SV4-CA05-S4W-CV7031 | CA05-07 TEMPORARY WALL ATTACHMENTS |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2466 | SV4-CA05-S4W-CV7032 | CA05-08 Temporary Attachments |
| 2467 | SV4-CA05-S4W-CV7033 | CA05 POST WELDING SURVEY DATA / VERIFICATIONS |
| 2468 | SV4-WLS-THW-ME7099 | LIQUID RADWASTE SYSTEM (WLS) PIPING HYDROSTATIC TESTING - DRAIN LINE |
| 2469 | SV4-CAS-P0W-ME7166 | FABRICATE AND INSTALL CAS PIPING SHOWN IN PHASE 7 |
| 2470 | SV4-2060-C0W-850008 | 196'-3 ELEV. FLOOR SLAB POUR # 8B |
| 2471 | SV3-MS10-MEW-860244 | INSTALLATION OF SWITCHGEAR ROOM #2 AHUs |
| 2472 | SV4-4033-ERW-860383 | INSTALLATION OF EMBEDDED CONDUIT ANNEX BUILDING AREA 3 ELEV 100'-0" & 107'-2" |
| 2473 | SV4-ML05-MLW-ME7167 | INSTALLATION OF UNIT 4 CA20 PENETRATIONS IN ROOMS 12365, 12454, 12463 |
| 2474 | SV4-ML05-MLW-ME7321 | INSTALLATION OF CA20 SUBMODULE 20 WALL PENETRATIONS ELEVATION 100’0” |
| 2475 | SV4-ML05-MLW-ME7322 | INSTALLATION OF CA20 SUBMODULE 22 WALL PENETRATION ELEVATION 114'6" |
| 2476 | SV4-CA01-S4W-CV6472 | CA01-31 SUB MODULE INSTALLATION |
| 2477 | SV4-CA20-S5W-CV7373 | SA-3 LEAK CHASE FABRICATION |
| 2478 | SV4-8200-MHW-CV7385 | MISC MAB WORK |
| 2479 | SV4-CA01-S5W-CV7389 | CA01 LANDING PLATE FABRICATION AND INSTALLATION |
| 2480 | SV4-WLS-THW-ME7477 | HYRDO TESTING OF KB15 WLS PIPING |
| 2481 | SV3-PSS-P0W-ME7502 | ASME SECTION III Fabrication/Installation of Isometric SV3-PSS-PLW-716 (Line Number PSS-PL-T081B) |
| 2482 | SV3-PSS-P0W-ME7504 | ASME SECTION III Fabrication/Installation of Isometric SV3-PSS-PLW-714 (line Number PSS-PL-T081B) |
| 2483 | SV3-PSS-P0W-ME7505 | ASME SECTION III Fabrication/Installation of Isometric SV3-PSS-PLW-713 (Line Number PSS-PL-T081B) |
| 2484 | SV4-WRS-P0W-ME7554 | INSTALLATION OF ANNEX BLD WRS EMBEDDED PIPING (ISOMETRIC SV4-WRS-PLW-410, 434, 456, 459, 45A, 45B, 45C, 45D, 468, 46B, 45V, 46D, 47A, 47B) |
| 2485 | SV4-WLS-THW-ME7682 | HYDRO TESTING OF KB28 WLS PIPING |
| 2486 | SV4-CA20-V2W-CV8064 | POST LOAD INSPECTION OF SPARE SUPER LIFT LUGS |
| 2487 | SV4-CA01-S4W-CV8679 | CA01-01 TEMPORARY WALL ATTACHMENTS |
| 2488 | SV4-CA01-S4W-CV8680 | CA01-02 TEMPORARY WALL ATTACHMENTS |
| 2489 | SV4-CA01-S4W-CV8681 | CA01-03 TEMPORARY WALL ATTACHMENTS |
| 2490 | SV4-CA01-S4W-CV8689 | CA01-11 TEMPORARY WALL ATTACHMENTS |
| 2491 | SV3-ECS-EKW-EL3149 | INSTALL ANNEX BLDG, AC LOAD CENTER, ECS-EK-14, ROOM 40413 |
| 2492 | SV3-ECS-EKW-EL3138 | INSTALL ANNEX BLDG, AC LOAD CENTER, ECS-EK-23, ROOM 40414 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2493 | SV3-ECS-EKW-EL3137 | INSTALL ANNEX BLDG, AC LOAD CENTER, ECS-EK-22, ROOM 40414 |
| 2494 | SV3-ECS-EKW-EL3148 | INSTALL ANNEX BLDG, AC LOAD CENTER, ECS-EK-13, ROOM 40413 |
| 2495 | SV3-2036-SHW-860241 | ELECTRICAL CABLE TRAY SUPPORT INSTALLATION IN THE TURBINE BUILDING, ELEVATION 100' , AREA 6, ROOM 20300 (TRAPEZE) |
| 2496 | SV3-ECS-EKW-EL3136 | INSTALL ANNEX BLDG, AC LOAD CENTER ECS-EK-21, ROOM 40414 |
| 2497 | SV4-CA01-S4W-CV8690 | CA01-12 TEMPORARY WALL ATTACHMENTS |
| 2498 | SV3-2031-SHW-860275 | ELECTRICAL CABLE TRAY SUPPORT NSTALLATION IN THE TURBINE BUILDING, ELEVATION 100' AREA 1, ROOM 20300 (TRAPEZE) |
| 2499 | SV3-2038-SHW-860273 | ELECTRICAL CABLE TRAY SUPPORT NSTALLATION IN THE TURBINE BUILDING, ELEVATION 100' AREA 8, ROOM 20300 (TRAPEZE) |
| 2500 | SV4-CA01-S4W-CV8691 | CA01-13 TEMPORARY WALL ATTACHMENTS |
| 2501 | SV4-CA01-S4W-CV8692 | CA01-14 Temporary Wall Attachments |
| 2502 | SV4-CA01-S4W-CV8693 | CA01-15 TEMPORARY WALL ATTACHMENTS |
| 2503 | SV4-CA01-S4W-CV8694 | CA01-16 TEMORARY WALL ATTACHMENTS |
| 2504 | SV4-CA01-S4W-CV8695 | CA01-17 TEMPORARY WALL ATTACHMENTS |
| 2505 | SV4-CA01-S4W-CV8696 | CA01-18 TEMPORARY WALL ATTACHMENTS |
| 2506 | SV4-CA01-S4W-CV8697 | CA01-19 TEMPORARY WALL ATTACHMENTS |
| 2507 | SV4-CA01-S4W-CV8703 | CA01-25 TEMPORARY WALL ATTACHMENTS |
| 2508 | SV4-CA01-S4W-CV8724 | CA01-47 TEMPORARY WALL ATTACHMENTS |
| 2509 | SV4-CA01-S4W-CV8725 | CA01-48 TEMPORARY WALL ATTACHMENTS |
| 2510 | SV3-SFS-PLW-ME0922 | FABRICATE AND INSTALL SFS EMBEDDED PIPING ISO SV3-SFS-PLW-604 |
| 2511 | SV4-CA01-S4W-CV8698 | CA01_20 TEMPORARY ATTACHMENT INSTALLATION |
| 2512 | SV3-1160-SSW-CV3061 | C8 Circular Trunk SPL28, 29, 30 |
| 2513 | SV3-PXS-PHW-ME3363 | FABRICATION /INSTALLATIN OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-011 |
| 2514 | SV4-CA20-S4W-CV4011 | CA20 WALL3 SOUTH FACE - OLP"S AND WELDED ATTACHMENTS INSTALLATION |
| 2515 | SV4-CA20-S4W-CV4019 | CA20 WALL 4 SOUTH FACE - OLP'S AND WELDED ATTACHMENTS INSTALLMENT |
| 2516 | SV4-CA20-S5W-CV4018 | CA20-05 UNSATISFACTORY IRs/N&Ds/E&DCRs AND LOOSE PARTS - STRUCTURAL |
| 2517 | SV4-CA20-S4W-CV5287 | INSTALLATION OF SUBMODULE CA20-10 |
| 2518 | SV4-CA20-S5W-CV5290 | CA20-11 UNSATISFACTORY IRs/N&Ds/E&DCRs AND LOOSE PARTS - STRUCTURAL |

# Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2519 | SV3-MS83-MEW-ME5589 | INSTALLATION OF STATOR COIL COOLING UNIT (TCS-MS-01) |
| 2520 | SV3-4031-SSW-850001 | STRUCTURAL STEEL, BATTERY ROOM WALLS |
| 2521 | SV3-DWS-P0W-861074 | INSTALLATION OF DWS PIPING ON MODULE R251 |
| 2522 | SV3-R251-MDW-861082 | INSTALLATION OF HVAC DUCT ON MODULE R251 |
| 2523 | SV4-CA20-S4W-CV5286 | CA20 WALL J2 EAST FACE - OLP"S AND WELDED ATTACHMENTS INSTALLATION |
| 2524 | SV3-1210-CEW-855000 | POST-INSTALLED EMBED PLATES AT 66'-6" ELEV |
| 2525 | SV4-CAS-PHW-ME1934 | INSTALLATION OF SMALL BORE CAS PIPING SUPPORTS (INCLUDING ISOMETRIC SV4-CAS-PLW-501 AND 504) |
| 2526 | SV3-ECS-EKW-EL3139 | INSTALL ANNEX BLDG AC LOAD CENTER ECS-EK-24 ROOM 40414 |
| 2527 | SV3-PXS-PHW-ME3782 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-024 |
| 2528 | SV0-XR01-S8W-CV0280 | Railroad Installation |
| 2529 | SV0-SDS-EWW-EL0307 | ELECTRICAL INSTALLATION OF SDS GRINDER PUMPS MS-600E, MS-600F AND MS-602D |
| 2530 | SV0-ZRS-EWW-TP1081 | 13.8KV Power Feed to West Side of NOI 7 |
| 2531 | SV4-FWS-P0W-ME1669 | Unit 4 Turbine Building El 100'-0": Fabrication & Installation of Embedded FWS Piping |
| 2532 | SV4-CB24-CBW-850000 | CB24 MODULE INSTALLATION |
| 2533 | SV3-EDS-DSW-EL3124 | INSTALL ANNEX BLDG NON CLASS 1E DC AND UPS SYSTEM - LOAD GROUP 4, ROOM 40310 |
| 2534 | SV3-ECS-EKW-EL3147 | INSTALL ANNEX BLDG, AC LOAD CENTER ECS-EK-12 ROOM 40413 |
| 2535 | SV3-ECS-EKW-EL3146 | INSTALL ANNEX BLDG AC LOAD CENTER ECS-EK-11 ROOM 40413 |
| 2536 | SV4-CA01-S4W-CV6460 | CA01-28 SUB MODULE INSTALLATION |
| 2537 | SV4-CA01-S4W-CV6496 | CA01-37 SUB MODULE INSTALLATION |
| 2538 | SV3-1134-SPW-850010 | SPL10 Installation |
| 2539 | SV4-2060-SSW-850012 | TB-12 STEEL ERECTION |
| 2540 | SV3-2060-C0W-850600 | 170' Elevation, Grout |
| 2541 | SV3-PXS-PHW-ME3784 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-02A |
| 2542 | SV3-1208-SCW-CV4921 | COURSE 12 UNIT 3 SHIELD BUILDING |
| 2543 | SV4-CA20-S4W-CV4007 | CA20 WALL 2 NORTH FACE - OLPs AND WELDED ATTACHMENT INSTALLATION |
| 2544 | SV3-1208-CCW-851004 | COURSE 4 CONCRETE PLACEMENT |
| 2545 | SV3-ECS-EAW-EL3134 | INSTALL ANNEX BLDG ECS-EA DISTRIBUTION PANEL ROOM 40414 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2546 | SV3-1130-C0W-850008 | CONTAINMENT CONCRETE PLACEMENT REFUEL CAVITY ELEV 87'-6" TO ELEV 95' |
| 2547 | SV3-4031-ERW-861109 | Installation of all Unscheduled Conduit for Lighting / Power Annex Bldg. Area 1, Elev. 100’, Battery Charger Room 40308 |
| 2548 | SV3-4031-ERW-861110 | Installation of all Unscheduled Conduit for Lighting / Power Annex Bldg. Area 1, Elev. 100’, Battery Charger Room 40310 |
| 2549 | SV3-4031-ERW-861111 | Installation of all Unscheduled Conduit for Lighting / Power Annex Bldg. Area 1, Elev. 100’, Battery Room 40307 |
| 2550 | SV3-4031-ERW-861112 | Installation of all Unscheduled Conduit for Lighting / Power Annex Bldg. Area 1, Elev. 100’, Battery Room 40309 |
| 2551 | SV3-1230-EGW-860944 | INSTALL GROUNDING FOR AUXILIARY BUILDING SHIELD WALL 100'-0" - 117'-6" |
| 2552 | SV4-WWS-P0W-860931 | INSTALLATION AND FABRICATION OF WASTE WATER SYSTEM (WWS) PIPING |
| 2553 | SV3-WWS-P0W-ME4629 | FABRICATION AND INSTALLATION OF WWS I.E. PIPING ELEVATION 100' |
| 2554 | SV4-CA01-S4W-CV6528 | CA01 ELEV 87.5' TO 94' OLPS AND WELDED ATTACHMENTS |
| 2555 | SV3-CA02-S5W-CV6271 | CA02 MISC. WORK, MISC. UNSAT. IRS / N&DS AND E&DCRS |
| 2556 | SV3-PXS-PHW-ME3358 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-01B |
| 2557 | SV3-R365-R3W-ME1694 | R365 MECHANICAL MODULE INSTALLATION |
| 2558 | SV4-ML05-MLW-ME6810 | INSTALLATION OF UNIT 4 CA20 WALL PENETRATIONS |
| 2559 | SV4-CA20-S4W-CV6827 | Installation of CA20 SA 1 Floor (Submodules 34,35,36,37) |
| 2560 | SV0-8200-MHW-CV7169 | MAB 50 TON OVERHEAD CRANE GIRDER CHANNEL WELDS |
| 2561 | SV4-WLS-THW-ME7680 | HYDRO TESTING OF KB27 WLS PIPING |
| 2562 | SV3-CA02-S5W-CV8034 | CA02 ON-SITE BASEMAT FABRICATION |
| 2563 | SV4-CA01-S4W-CV8682 | CA01-04 TEMPORARY WALL ATTACHMENTS |
| 2564 | SV3-WLS-PLW-ME0872 | Fabricate and Install WLS Piping Lines WLS-PL-L062, & L110B of Iso SV3-WLS-PLW-731 |
| 2565 | SV3-CB47-S5W-860988 | CB47 UNSATISFACTORY IRs / N&Ds / E&DCRs AND LOOSE PARTS - STRUCTURAL |
| 2566 | SV4-CA01-S4W-CV6484 | CA01-34 SUB MODULE INSTALLATION |
| 2567 | SV4-0000-C0W-850021 | TRANSFORMER FOUNDATION WALL POUR #21 |
| 2568 | SV4-WRS-P0W-ME5327 | Fabrication/Installation of Small Bore WRS Leak Chase Piping Including SV4-WRS-PLW-80D, -80E, -80F, -86M |
| 2569 | SV3-2035-SHW-860253 | ELECTRICAL CABLE TRAY SUPPORT INSTALLATION IN THE TURBINE BUILDING ELEVATION 100' AREA 5 ROOM 20300 |
| 2570 | SV4-0150-ERW-860386 | INSTALLATION OF CONDUIT SLEEVES FOR PENETRATION IN UNIT 4 TRANSFORMER AREA |
| 2571 | SV3-PXS-PHW-ME5539 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-PXS-PLW-298 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2572 | SV3-PXS-PHW-ME3783 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-025 |
| 2573 | SV3-PXS-PHW-ME3362 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-01Z |
| 2574 | SV3-PXS-PHW-ME3360 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-01K |
| 2575 | SV3-PXS-PHW-ME3786 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-02E |
| 2576 | SV3-VWS-P0W-861115 | Install Isometric SV3-VWS-PLW-05A Large Bore Piping |
| 2577 | SV3-VWS-P0W-861116 | Install Isometric SV3-VWS-PLW-05K Large Bore Piping |
| 2578 | SV3-VWS-P0W-861117 | Install Isometric SV3-VWS-PLW-50A Large Bore Piping |
| 2579 | SV3-VWS-P0W-861119 | Install Isometric SV3-VWS-PLW-50L Large Bore Piping |
| 2580 | SV3-VWS-P0W-861120 | Install Isometric SV3-VWS-PLW-50W Large Bore Piping |
| 2581 | SV3-VWS-P0W-861121 | Install Isometric SV3-VWS-PLW-50X Large Bore Piping |
| 2582 | SV3-VWS-P0W-861122 | Install Isometric SV3-VWS-PLW-50Y Large Bore Piping |
| 2583 | SV3-VWS-P0W-861123 | Install Isometric SV3-VWS-PLW-50Z Large Bore Piping |
| 2584 | SV3-VWS-P0W-861124 | Install Isometric SV3-VWS-PLW-51A Large Bore Piping |
| 2585 | SV3-VWS-P0W-861125 | INSTALL ISOMETRIC SV3-VWS-PLW-51B LARGE BORE PIPING |
| 2586 | SV3-VWS-P0W-861126 | Install Isometric SV3-VWS-PLW-52A Large Bore Piping |
| 2587 | SV3-VWS-P0W-861128 | Install Isometric SV3-VWS-PLW-52L Large Bore Piping |
| 2588 | SV3-VWS-P0W-861129 | Install Isometric SV3-VWS-PLW-502 Large Bore Piping |
| 2589 | SV3-VWS-P0W-861130 | Install Isometric SV3-VWS-PLW-513 Large Bore Piping |
| 2590 | SV3-VWS-P0W-861131 | INSTALL ISOMETRIC SV3-VWS-PLW-519 LARGE BORE PIPING |
| 2591 | SV3-VWS-P0W-861134 | Install Isometric SV3-VWS-PLW-532 Large Bore Piping |
| 2592 | SV3-VWS-P0W-861135 | Install Isometric SV3-VWS-PLW-533 Large Bore Piping |
| 2593 | SV3-VWS-P0W-861136 | Install Isometic SV3-VWS-PLW-537 Large Bore Piping |
| 2594 | SV3-VWS-PHW-861139 | Install Isomertic SV3-VWS-PLW-50A Large Bore Pipe Supports |
| 2595 | SV3-VWS-PHW-861140 | Install Isometric SV3-VWS-PLW-50B Large Bore Piping Supports |
| 2596 | SV3-VWS-PHW-861141 | Install Isometric SV3-VWS-PLW-50L Large Bore Piping Supports |
| 2597 | SV3-VWS-PHW-861143 | Install Isometric SV3-VWS-PLW-50X Large Bore Pipe Supports |
| 2598 | SV3-VWS-PHW-861144 | Install Isometric SV3-VWS-PLW-50Y Large Bore Pipe Supports |
| 2599 | SV3-VWS-PHW-861145 | Install Isometric SV3-VWS-PLW-50Z Large Bore Pipe Supports |
| 2600 | SV3-VWS-PHW-861146 | Install Isometric SV3-VWS-PLW-51A Large Bore Pipe Supports |
| 2601 | SV3-VWS-PHW-861148 | Install Isometric SV3-VWS-PLW-52A Large Bore Pipe Supports |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2602 | SV3-VWS-PHW-861151 | Install Isometric SV3-VWS-PLW-502 Large Bore Pipe Supports |
| 2603 | SV3-VWS-PHW-861152 | Install Isometric SV3-VWS-PLW-513 Large Bore Pipe Supports |
| 2604 | SV3-VWS-PHW-861156 | Install Isometric SV3-VWS-PLW-532 Large Bpre Pipe Supports |
| 2605 | SV3-VWS-PHW-861157 | Install Isometric SV3-VWS-PLW-533 Large Bore Pipe Supports |
| 2606 | SV3-VWS-PHW-861158 | Install Isometric SV3-VWS-PLW-537 Large Bore Pipe Supports |
| 2607 | SV0-ZRS-EWW-TP1795 | Temporary Power for NOI 7 |
| 2608 | SV3-VCS-SHW-ME2331 | INSTALLATION OF CONTAINMENT VCS HVAC SUPPORTS FOR AZIMUTH 240 - 285 |
| 2609 | SV3-PSS-P0W-ME7503 | ASME SECTION III Fabrication/Installation of Isometric SV3-PSS-PLW-715 (Line Number PSS-PL-T081B) |
| 2610 | SV3-1210-CEW-CV7695 | NDE OF JOSEPH OAT EMBED PLATES WITH WELDABLE COUPLERS |
| 2611 | SV0-0000-M0W-MU7690 | Mock-up for Qualification of ASME Tube Bending |
| 2612 | SV0-0000-MYW-CT7674 | MECHANICAL/ABRASIVE CLEANING OF MISCELLANEOUS STEEL & EQUIPMENT. |
| 2613 | SV3-FPS-PHW-860506 | INSTALLATION OF FIRE PROTECTING SYSTEM SUPPORTS (FPS) |
| 2614 | SV0-CE01-CEW-CV7471 | NDE OF CIVES EMBEDS WITH WELDABLE COUPLERS |
| 2615 | SV4-WRS-THW-ME7465 | TESTING OF CA20 WALL LEAK CHASES AND CONNECTED PIPING |
| 2616 | SV0-CA20-CCW-MU6307 | CA20 CONCRETE PLACEMENT MOCK UP FOR CONSTRUCTION JOINT AT ELEV. 85'-0" |
| 2617 | SV3-RNS-MLW-860363 | ASME SECTION III - INSTALLATION OF CONTAINMENT VESSEL PENETRATION SV3-RNS-PY-C01 (P19) |
| 2618 | SV3-RNS-MLW-860364 | ASME SECTION III - INSTALLATION OF CONTAINMENT VESSEL PENETRATION SV3-RNS-PY-C02 (P20) |
| 2619 | SV3-SFS-MLW-860365 | ASME SECTION III - INSTALLATION OF CONTAINMENT VESSEL PENETRATION SV3-SFS-PY-C02 (P22) |
| 2620 | SV3-CAS-P0W-ME6006 | INSTALLATION OF ANNEX BLDG CAS PIPING (ISO SV3-CAS-PLW-20J, 20K, 20L, & 20M) |
| 2621 | SV0-0000-CCW-CV5530 | Miscellaneous Grouting in 300 series Buildings/Yard |
| 2622 | SV3-MT2D-MEW-ME5377 | INSTALLATION OF MSR SHELL DRAIN TANK HDS-MT-02A/B |
| 2623 | SV3-1130-SLW-855000 | UPENDER PIT, FABRICATION |
| 2624 | SV4-CA01-S4W-CV6476 | CA01-32 SUBMODULE INSTALLATION |
| 2625 | SV4-1220-CCW-MU5102 | UNIT 4 MOCK-UP FOR CORE DRILLING IN CONCRETE PLACEMENT OUTSIDE THE CVBH AT ELEVATION 72'-6" |
| 2626 | SV3-CA20-S4W-CV4804 | SURVEY ROOMS FOR PLUMBNESS/LEVEL/WALL FLATNESS FOR SUB-ASSEMBLIES 1, 2, 3 & 4 |
| 2627 | SV3-CA01-V2W-CV4802 | INSTALL CA01 GUIDE PIN COLLAR MOUNTING PLATES |
| 2628 | SV3-ML05-MLW-ME4786 | INSTALLATION OF 100'0" AREA 3,4,5 PIPING PENETRATIONS |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2629 | SV3-WRS-P0W-ME4753 | INSPECTION OF CASK WASHDOWN PIT LEAK CHASE PIPING |
| 2630 | SV3-1130-C0W-850004 | CONTAINMENT CONCRETE PLACEMENT REFUEL CAVITY ELEV 95' TO 98' 1/2" |
| 2631 | SV3-WRS-P0W-ME4752 | INSPECTION OF CASK LOADING PIT LEAK CHASE PIPING |
| 2632 | SV3-PXS-PHW-ME3780 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-021 |
| 2633 | SV3-WRS-P0W-ME4751 | INSPECTION OF FUEL TRANSFER CANAL LEAK CHASE PIPING |
| 2634 | SV3-WRS-P0W-ME4750 | INSPECTION OF SPENT FUEL POOL LEAK CHASE PIPING |
| 2635 | SV3-WRS-P0W-ME4563 | SV3-WRS-GNR-000054 REPAIR WORK FOR SV3-WRS-PLW-838 |
| 2636 | SV3-VYS-PHW-ME4479 | , FABRICATE AND INSTALL ANNEX HOT WATER HEATING SYSTEM (VYS) PIPING SUPPORTS FOR SV3-VYS-P0W-ME4478 , |
| 2637 | SV3-CAS-PHW-ME4475 | The installation of the Annex CAS Piping Support for WP ( SV3-CAS-P0W-ME4474) |
| 2638 | SV3-WRS-PLW-ME4462 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES SV3-WRS-PLW-84A) |
| 2639 | SV3-WRS-P0W-ME4456 | SV3-WRS-GNR-000056 REPAIR WORK FOR SV3-WRS-PLW-847 |
| 2640 | SV3-WRS-P0W-ME4451 | SV3-WRS-GNR-000057 REPAIR WORK FOR SV3-WRS-PLW-83C |
| 2641 | SV3-WRS-PLW-ME4449 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES SV3-WRS-PLW-81F) |
| 2642 | SV3-WRS-PLW-ME4448 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES SV3-WRS-PLW-81E) |
| 2643 | SV3-WRS-P0W-ME4430 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES ISOMETRICS SV3-WRS-PLW-80B, 80C AND 80U |
| 2644 | SV3-VWS-P0W-ME4426 | ASME SECTION III- FABRICATION/ INSTALLATION OF ISOMETRIC# SV3-VWS-PLW-910 (LINE# VWS-PL-L032 |
| 2645 | SV3-WRS-P0W-ME4423 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES ISOMETRICS SV3-WRS-PLW-801, 80S, -86E |
| 2646 | SV3-SS01-Z0W-CV4377 | UNIT 3 STRUCTURAL STEEL SAFETY CLASS E REQUIREMENTS |
| 2647 | SV3-ASS-PHW-ME4294 | FABRICATE/INSTALL OF AUXILIARY STEAM (ASS) SUPPORTS (PORTION 5) |
| 2648 | SV4-1000-Z0W-CV3912 | UNIT 4 SHIELD BUILDING REINFORCED CONCRETE REQUIREMENTS |
| 2649 | SV3-CAS-P0W-ME3429 | INSTALLATION OF SMALL BORE CAS PIPING (INCLUDES SV3-CAS-PLW-336) |
| 2650 | SV4-MSS-P0W-860357 | INSTALLATION AND FABRICATION OF MAIN STEAM SYSTEM (MSS) PIPING |
| 2651 | SV4-MSS-P0W-860358 | INSTALLATION AND FABRICATION OF MAIN STEAM SYSTEM (MSS) PIPING |
| 2652 | SV3-WRS-P0W-ME3858 | SV3-WRS-GNR-000055 REPAIR WORK FOR SV3-WRS-PLW-872 |
| 2653 | SV3-WRS-P0W-ME3857 | SV3-WRS-GNR-000060 REPAIR WORK FOR SV3-WRS-PLW-83G |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2654 | SV3-WRS-P0W-ME3637 | SV3-WRS-GNR-000049 REPAIR WORK FOR SV3-WRS-PLW-81Q |
| 2655 | SV3-DTS-PHW-ME3582 | INSTALLATION OF PIPE SUPPORTS ON ISO SV3-DTS-PLW-01AP AND SV3-DTS-PLW-01AN |
| 2656 | SV3-PXS-P0W-ME3508 | ASME SECTION III - PERFORM RADIOGRAPHY TEST ON SV3-PXS-PLW-014 SHOP WELD 15 |
| 2657 | SV3-PGS-CCW-CV3426 | UNIT 3 JACK & BORE AND PGS ENCASEMENT CONSTRUCTION |
| 2658 | SV4-CCS-P0W-ME3112 | INSTALLATION OF LARGE BORE CCS PIPING (INCLUDES ISOMETRIC SV4-CCS-PLW-740, 750) |
| 2659 | SV3-CVS-PHW-ME2926 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-CVS-PLW-110 |
| 2660 | SV4-CA20-S4W-CV4004 | CA20-01-MAP OUT TEMPORARY ATTACHMENTS |
| 2661 | SV3-WWS-PHW-ME3074 | INSTALLATION OF ANNEX WWS PIPING SUPPORTS (FOR WP SV3-WWS-P0W-ME2693) |
| 2662 | SV3-PXS-PHW-ME4508 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FO ISOMETRIC SV3-PXS-PLW-02V |
| 2663 | SV3-PXS-P0W-861007 | INSTALL ISOMETRIC SV3-PXS-PLW-934 LARGE BORE PIPING |
| 2664 | SV4-1000-XEW-CV2913 | UNIT 4 POWER BLOCK EXCAVATION AND BACKFILL OF UTILITIES |
| 2665 | SV3-PXS-P0W-ME2890 | ASME SECTION III- FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-018 (LINE NUMBERS PXS-PL-L112A) |
| 2666 | SV3-0000-EGW-EL2804 | PERFORM INSTALLATION OF UNDERGROUND COMMODITIES (SV3-SITE STATION GROUNDING GRID) FOR GROUND GRID AREA, M1300 |
| 2667 | SV3-VWS-PHW-ME2800 | INSTALLATION OF VWS SUPPORTS FOR ISOMETRICS SV3-VWS-PLW-20L |
| 2668 | SV3-PXS-P0W-ME2751 | ASME Section III-Fabrication/Installation of Isometric# SV3-PXS-PLW-02R (Line Numbers PXS-PL-L136B) |
| 2669 | SV3-MS10-MEW-ME2472 | Install TB Sampling Rooms AHU (VTS-MS-01A/1B) |
| 2670 | SV4-1000-CRW-CV2374 | FABRICATION OF REBAR FOR UNIT 4 NUCLEAR ISLAND |
| 2671 | SV3-2053-SHW-EL8560 | Electrical Cable Tray Support Installation in the Turbine Building, Elevation 141’-3”, Area 2, Room 20500 |
| 2672 | SV3-ML05-MLW-ME1982 | ATTACHMENT OF WELDED COUPLINGS 82'-6" FLOOR PENETRATIONS |
| 2673 | SV4-RWS-MEW-TP1980 | REWORK ASSOCIATED WITH NONCONFORMANCE V-ND-11-0181 |
| 2674 | SV0-1208-SCW-MU1894 | MOCKUP-SHIELD WALL PANEL MOCKUP |
| 2675 | SV0-CA05-MHW-RI1887 | CONSTRUCTION OF CA05 PLATEN |
| 2676 | SV4-CWS-THW-ME1722 | UNIT 4 CIRCULATING WATER SYSTEM (CWS) HYDRO TEST FROM PRE CAST CONCRETE PIPE (PCCP) TO TURBINE BUILDING |
| 2677 | SV3-WLS-PLWP-ME1655 | Fabricate And Install WLS Piping Iso SV3-WLS-PLW-750 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2678 | SV3-1220-CEW-CV1605 | Auxiliary Building Embed Plates & Anchor Bolts-EL 82'6" - Area 5&6 |
| 2679 | SV0-0000-M0W-MU1585 | Mock-up for Qualification of Cleaning Methods |
| 2680 | SV3-CWS-XEW-CV0056 | GROUTING OF PHASE 2 CWS PIPE JOINTS (PCCP) AND FLOWABLE FILL PLACEMENT |
| 2681 | SV3-ML05-MLW-ME6134 | ASME SECTION III - ATTACH CODE DATA PLATES ON CA20 PENETRATIONS |
| 2682 | SV3-2054-SHW-EL8954 | Electrical Cable Tray Supplemental Steel Installation in the Turbine Building, Below Elevation 169'-0" |
| 2683 | SV3-ME01-PLW-ME1167 | Condenser C-1st Extraction Piping (Extraction Steam) |
| 2684 | SV3-CA20-S4W-CV0436 | Installation of CA20 SA3 Overlay Plates RESERVED FOR RUSSELL FINDLEY |
| 2685 | SV4-CA20-MHH-040 | INSTALLATION OF UNIT 4 CA20 MODULE |
| 2686 | SV3-2070-SAW-850000 | ROOF ELEV. FLOOR SLAB. STUD INSTALLATION |
| 2687 | SV3-SGS-P0W-ME6695 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC SV3-SGS-PLW-080, -81 (LINE NUMBERS SGS-PL-L009B), , |
| 2688 | SV3-Q240-Q2W-861063 | INSTALLATION OF MECHANICAL MODULE 1120-Q2-40 |
| 2689 | SV4-2020-MEW-860398 | CONDENSER B CONECTION PIECE ASSEMBLY |
| 2690 | SV4-4032-ERW-860382 | INSTALLATION OF EMBEDDED CONDUIT, ANNEX BUILDING, AREA 2, ELEV. 100'-0" |
| 2691 | SV4-CWS-PHW-ME7146 | INSTALLATION OF PIPE SUPPORTS FOR PIPING PACKAGAE SV4-CWS-P0W-ME7145 |
| 2692 | SV3-MT02-MHH-004 | LIFTING OF UNIT 3 ACCUMULATOR TANKS |
| 2693 | SV4-WLS-THW-861171 | PNEUMATIC TEST OF THE HDPE PORTION OF THE UNIT 4 WLS SYSTEM NORTH OF THE VEHICLE BARRIER DITCH |
| 2694 | SV3-WLS-THW-861170 | PNEUMATIC TEST OF THE HDPE PORTION OF UNIT 3 WLS SYSTEM NORTH OF THE VEHICLE BARRIER DITCH |
| 2695 | SV4-0000-C0W-850007 | TRANSFORMER FOUNDATION, WALL POUR #7 |
| 2696 | SV3-WLS-P0W-861168 | INSTALL ELECTRO-FUSION COUPLINGS ON UNIT 3 WLS LINE ISOMETRICS SV3-WLS-PLW-80GD, 80GE, 80GF, 80GG, 80GH, 80GJ, 80GK, 80GL, 80GM, 80GN |
| 2697 | SV3-FPS-P0W-860729 | INSTALLATION OF FIRE PROTECTION PIPING |
| 2698 | SV4-CA01-S4W-CV6574 | U4-CA01 LIFTING FRAMES AND BRACING SUBMUDULES 27 THRU 31, -34 & -46 |
| 2699 | SV3-PXS-PHW-ME5672 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-320 |
| 2700 | SV3-PXS-PHW-881160 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-PXS-PLW-284 |
| 2701 | SV4-WLS-P0W-861169 | INSTALL ELECTRO-FUSION COUPLINGS IN UNIT 4 WLS LINE ISOMETRICS SV4-WLS-PLW-81GP, 81GQ, 81GR, 81GS, 81GU, 81GV, 81GW, 81GX, 81Y |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2702 | SV4-ML05-MLW-ME7944 | INSTALL CA01 ASME PROCESS PIPE PENETRATION SV4-11300-ML-P78 & SV4-11300-ML-P79 |
| 2703 | SV4-ML05-MLW-ME7942 | INSTALL CA01 PENETRATION SV4-11300-ML-P41 |
| 2704 | SV4-2101-C0W-850403 | 122' ELEVATION WALLS POUR 2NW |
| 2705 | SV4-VWS-P0W-860370 | Fabrication/Installation of VWS Piping (Isometric Drawings SV4-VWS-PLW-260, -384 and -389) |
| 2706 | SV4-CA01-S4W-CV6498 | CA01-38 SUB MODULE INSTALLATION |
| 2707 | SV3-MSS-P0W-ME4647 | INSTALLATION OF MSS PIPING |
| 2708 | SV3-PXS-PHW-ME3790 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-02P |
| 2709 | SV3-PXS-P0W-861009 | INSTALL ISOMETRIC SV3-PXS-PLW-936 LARGE BORE PIPING |
| 2710 | SV3-PXS-P0W-861012 | INSTALL ISOMETRIC SV3-PXS-PLW-944 LARGE BORE PIPING |
| 2711 | SV4-MSS-P0W-860355 | INSTALLATION OF MAIN STEAM SYSTEM (MSS) PIPING |
| 2712 | SV4-CB25-CBW-850000 | CB25 MODULE INSTALLATION |
| 2713 | SV4-CA03-S4W-860271 | CA03 INSTALL & REMOVE TEMPORARY WALL ATTACHMENTS |
| 2714 | SV4-ML05-MLW-ME7693 | INSTALL CA01 PENETRATION SV4-11202-ML-P04 |
| 2715 | SV4-DWS-P0W-860369 | FABRICATION/INSTALLATION OF DWS PIPING (INCLUDING ISOMETRIC DRAWINGS SV4-DWS-PLW-60D, -624 AND -625) |
| 2716 | SV4-VWS-PHW-860400 | INSTALLATION OF LARGE BORE VWS PIPING SUPPORTS (INCLUDES ISOMETRICS: SV4-VWS-PLW-486) |
| 2717 | SV3-SFS-P0W-861166 | ASME SECTION III – FABRICATION/INSTALLATION OF PIPING FOR ISOMETRICS SV3-SFS-PLW-786 AND SV3-SFS-PLW-787 (LINE NUMBER L037) |
| 2718 | SV3-PXS-P0W-861015 | INSTALL ISOMETRIC SV3-PXS-PLW-947 LARGE BORE PIPING |
| 2719 | SV3-PXS-PHW-ME3359 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-01H |
| 2720 | SV3-PXS-PHW-861021 | INSTALL ISOMETRIC SV3-PXS-PLW-938 LARGE BORE PIPE SUPPORTS |
| 2721 | SV3-PXS-PHW-861017 | INSTALL ISOMETRIC SV3-PXS-PLW-934 LARGE BORE PIPE SUPPORTS |
| 2722 | SV3-2030-CCW-CV0123 | 100 Ft Elevation Slabs (Includes Elevated Slabs and Roof Slabs for Elev. 94"3 & 100') |
| 2723 | SV3-CA01-S5W-CV4238 | INSTALLATION OF CA01 SUB-MODULE INTERNAL LEAK CHASE CAPS |
| 2724 | SV3-CA01-S5W-CV4251 | CA01 BEND TESTING OF STUDS REMOVED FOR WELD ISSUES |
| 2725 | SV3-CA02-S5W-CV6127 | CA02 REBAR FABRICATION, TORQUEING AND TESTING |
| 2726 | SV3-2043-SHW-861333 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE UNIT 3 TURBINE BUILDING ELEVATION 120' - 6", AREA 3, COLUMNS 18 TO 19 & L1 TO P.1 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2727 | SV4-MT71-C0W-850013 | Waste Water Retention Basin Wall Pour # 13 |
| 2728 | SV3-2070-C0W-850002 | UNIT 3, TURBINE BUILDING ROOF SLAB, POUR #2 |
| 2729 | SV4-1103-ERW-861803 | FABRICATION AND INSTALLATION OF EMBEDDED 11208 RNS VALVE ROOM X CONDUITS |
| 2730 | SV3-1000-ATW-850000 | UNIT 3, AUXILIARY BUILDING, PHYZITE SEAL |
| 2731 | SV4-4042-SAW-850002 | UNIT 4 - ANNEX SUPPLEMENT STEEL, ELEV 117' - 6", AREA 2, CL 6 TO CL 7.1 |
| 2732 | SV3-4031-ERW-861317 | INSTALLATION OF SCHEDULED CONDUIT IN ROOM 40308, ANNEX BUILDING, AREA 1, ELEVATION 100' - 0" |
| 2733 | SV3-4031-ERW-861242 | INSTALL CABLE TRAY IN RMS 40307-40310 ANNEX BLDG, AREA 1, ELEV. 100'(WP2) |
| 2734 | SV4-1231-ERW-EL7203 | INSTALL CONDUIT SLEEVES FOR PENETRATIONS IN UNIT 4 AUX BUILDING FLOOR SLABS, EL 100'-0"AREA 1 RMS. 12304 & 12305 |
| 2735 | SV4-1232-ERW-EL7205 | INSTALL CONDUIT SLEEVES FOR PENETRATIONS IN UNIT 4 AUX BUILDING FLOOR SLABS, EL 100'-0"AREA 2 RMS. 12301, 12302, 12303 & 12311 |
| 2736 | SV4-1231-EYW-EL7204 | INSTALL CONDUIT SLEEVES FOR PENETRATIONS IN PRECAST CONCRETE PANEL. AND CAST-IN-PLACE CONCRETE (ABOVE PRECAST CONCRETE PANELS ) UNIT 4, AUXILIARY BUILDING, ELEVATION 100'-0", AREA 1. WORK THIS PACKAGE IN CONJUNCTION WITH CIVIL WORK PACKAGE SV4-1230-CPW-XX |
| 2737 | SV4-CA02-S8W-860171 | CA02 Install Lifting Lugs for NI Set |
| 2738 | SV4-1154-ERW-861816 | FABRICATION AND INSTALLATION OF CABLE TRAY SUPPORTS FOR AREA 4 ON RING2 OF THE CONTAINMENT VESSEL AT ELEVATION131'-9" TO 170'-0" |
| 2739 | SV4-4030-SSW-850012 | 100'- ELEV. S02. STAIRS |
| 2740 | SV4-WWS-THW-861595 | HYDRO TEST THE UNIT 4 WASTE WATER SYSTEM (WWS) HDPE PIPING |
| 2741 | SV4-1153-ERW-861814 | FABRICATION AND INSTALLATION OF CABLE TRAY SUPPORTS ATTACHING TO THE CONTAINMENT VESSEL IN AREA 3 AT ELEVATION 170' TO 176' |
| 2742 | SV4-1153-ERW-861811 | FABRICATION & INSTALLATION OF CABLE TRAY SUPPORTS FOR AREA 3 ON RING 2 OF THE CONTAINMENT VESSEL AT ELEVATION 131'-9" TO 170'-0" |
| 2743 | SV4-1154-ERW-861807 | FABRICATION & INSTALLATION OF CONDUIT SUPPORTS FOR AREA 4 ON RING 2 OF THE CONTAINMENT VESSEL AT ELEVATION 131'-9" TO 170'-0" |
| 2744 | SV4-1152-ERW-861809 | FABRICATION & INSTALLATION OF CABLE TRAY SUPPORTS FOR AREA 2 ON THE RING 2 OF THE CONTAINMENT VESSEL AT ELEVATION 131'-9" TO 170' |
| 2745 | SV3-4051-SAW-850001 | SUPPLEMENTARY STEEL, ELEVATION 135'-3", AREA 1 CL E/I.1 & 11.09/11.15 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2746 | SV4-1151-ERW-861805 | FABRICATION & INSTALLATION OF CONDUIT SUPPORTS FOR AREA 1 & 2 ON THE RING 2 OF THE CONTAINMENT VESSEL AT ELEVATION 131'-9" TO 170'-0" |
| 2747 | SV4-1150-ERW-861808 | FABRICATION & INSTALLATION OF HYDROGEN IGNITER CONDUIT SUPPORTS ATTACHING TO THE CONTAINMENT VESSEL AT ELEVATION 170' TO 176' |
| 2748 | SV4-1153-ERW-861813 | FABRICATION & INSTALLATION OF CABLE TRAY SUPPORTS FOR AREA 3 ON RING 2 OF THE CONTAINMENT VESSEL AT ELEVATION 131'-9" TO 170'-0" |
| 2749 | SV3-CA35-ERW-861470 | FABRICATION AND INSTALLATION OF ELECTRICAL PENETRATIONS WITHIN THE CA35 MODULE |
| 2750 | SV4-1152-ERW-861810 | FABRICATION AND INSTALLATION OF CABLE TRAY SUPPORTS ATTACHING TO THE CONTAINMENT VESSEL IN AREA 2 AT ELEVATION 170' TO 176' |
| 2751 | SV3-4031-ERW-861319 | Installation of Scheduled Conduit in Room 40310, Annex Building, Area 1, Elevation 100'-0" |
| 2752 | SV4-1153-ERW-861806 | FABRICATION AND INSTALLATION OF CONDUIT SUPPORTS FOR AREA 3 ON RINGS 2 OF THE CONTAINMENT VESSEL AT EL. 131'-9" TO 170'-0" |
| 2753 | SV4-1154-ERW-861817 | FABRICATION AND INSTALLATION OF CABLE TRAY SUPPORTS ATTACHING TO THE CONTAINMENT VESSEL IN AREA 4 AT ELEVATION 170' TO 176' |
| 2754 | SV4-CA03-S4W-861518 | CA03 POST WELDING SURVEY DATA/VERIFICATIONS |
| 2755 | SV3-4031-ERW-861245 | Install Cable Tray in Rms 40307-40310 Annex Bldg. Area 1, Elev. 100¿ (WP5) |
| 2756 | SV3-4031-ERW-861246 | Install Cable Tray in Rms 40307-40310 Annex Bldg. Area 1, Elev. 100¿ (WP6) |
| 2757 | SV3-2070-SAW-850001 | UNIT 3 TURBINE BUILDING ELEVATION 230'-9" SHEAR STUD INSTALLATION |
| 2758 | SV4-4030-SSW-850014 | 100' ELEV. S04 STAIR |
| 2759 | SV4-CB11-CBW-850000 | CONTAINMENT BUILDING-INSTALLATION OF MODULE CB11 AT ELEV 84'-6" |
| 2760 | SV3-4052-SAW-850003 | Unit 3, Supplemental Steel for Annex Elev 135'-3" |
| 2761 | SV3-4052-SAW-850005 | Supplemental Steel 135'-3" Elev. Annex Bldg, Area 2 from CL 7.1-9 & G-H |
| 2762 | SV3-R251-ERW-861194 | Module R251 Electrical Cable Tray and Tray Grounding Installation |
| 2763 | SV3-2141-SAW-850000 | UNIT 3, FIRST BAY , 117'-6" ELEV., STUD INSTALLATION |
| 2764 | SV4-1160-SPW-850031 | SPL31, SPL32 & SPL33 Installation |
| 2765 | SV4-CA20-C0W-850001 | Auxiliary Building-Submodule CA20-Elev 75'-6"- Concrete Floors 64 & 65 FLOORS |
| 2766 | SV4-1160-SPW-850028 | SPL28, 29 & 30 Structural Steel Installation |
| 2767 | SV3-2070-C0W-850005 | ROOF ELEV FLOOR SLAB, POUR #5 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2768 | SV4-1150-EGW-861819 | INSTALL GROUNDING IN CONTAINMENT & SHIELD WALLS FROM EL. 117'-6" - 135'-3" EXCLUDING AREAS WHERE SHIELD WALL & AUXILIARY BUILDING MEET |
| 2769 | SV3-MSS-PHW-ME4676 | INSTALLATION AND FABRICATION OF MAIN STEAM SYSTEM(MSS) PIPING SUPPORT |
| 2770 | SV4-WWS-P0W-861605 | INSTALLATION OF ANNEX BUILDING WWS PIPING (ISO SV4-WWS-PLW-414,415,416,417,974,975 & 976) |
| 2771 | SV4-1130-C0W-850010 | CONTAINMENT BLDG - EAST CONCRETE - ELEV 83'-0" & 84'-6" TO 87'-6" |
| 2772 | SV3-MP80-MEW-861785 | LUBE OIL TRANSFER PUMP INSTALLATION |
| 2773 | SV3-EDS2-EAW-EL6230 | INSTALL (EDS2) EA - LOW VOLTAGE DISTRIBUTION PNL EQUIPMENT FOR ANNEX COMPUTER ROOM "B" - 40411 ELEV. 118'- 6" |
| 2774 | SV4-MT6Z-MEW-ME8562 | MAIN LUBE OIL TANK |
| 2775 | SV4-MT71-C0W-850009 | Waste Water Retention Basin Wall Pour # 9 |
| 2776 | SV4-CB21-CBW-850000 | CONTAINMENT BUILDING-INSTALLATION OF MODULE CB21 |
| 2777 | SV4-1200-T2W-CV5940 | HSB ASSEMBLY & INSTALLER QUALIFICATION FOR U4 AUXILIARY BUILDING |
| 2778 | SV3-1208-CCW-851005 | SV3 SHIELD BLDG COURSES 5 & 6 CONCRETE |
| 2779 | SV0-863-THW-ME7837 | TEST UNDERGROUND PIPING UTILITIES POTABLE WATER, SANITARY SEWER, FIRE SUPPRESSION FOR BUILDING 304 |
| 2780 | SV4-CB12-CBW-850000 | CONTAINMENT BUILDING-INSTALLATION OF MODULE CB12 AT ELEV 84'-6" |
| 2781 | SV3-CA36-ERW-861471 | FABRICATION AND INSTALLATION OF ELECTRICAL PENETRATIONS WITHIN THE CA36 MODULE |
| 2782 | SV3-2052-SHW-861954 | ISTALLATION OF CABLE TRAY SUPPORTS IN TURBINE BUILDING (ELEV. 141'-3" AREA 2) |
| 2783 | SV0-8200-MHW-861992 | MISC. MAB WORK |
| 2784 | SV0-CA00-S5W-862025 | CAxx FLOOR REPAIRS |
| 2785 | SV4-RNS-P0W-861702 | ASME III FABRICATION/INSTALLATION OF CA20 LARGE BORE PIPING FOR ISOMETRICS SV4-RNS-PLW-176 |
| 2786 | SV3-2040-SHW-861918 | ELECTRICAL CABLE TRAY TRAPEZE SUPPORTS FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 120'-6", AREA 0 |
| 2787 | SV3-2042-SHW-861748 | INSTALLATION OF TRAPEZE CABLE TRAY SUPPORTS IN TURBINE BUILDING (ELEV. 120'-6" AREA 2) |
| 2788 | SV3-CVS-P0W-860234 | COMPLETE INSTALLATION OF CVS PIPING ON MODULE KQ23 |
| 2789 | SV3-2048-SHW-861896 | ELECTRICAL CABLE TRAY TRAPEZE SUPPORTS FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING,ELEVATION120 6,AREA8 |
| 2790 | SV3-2053-SHW-861956 | Installation of Cable Tray Supports in Turbine Buliding (Elev.141'3"ARREA) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2791 | SV4-R151-ERW-861347 | U4 Module R151 Electrical Cable Tray and Tray Grounding Installation |
| 2792 | SV3-2046-SHW-861851 | ELECTRICAL CABLE TRAY TRAPEZE SUPPORTS FABRAICATION AND INSTALLATION IN THE UNIT 3 TURBINE BULIDING,ELEVATION 120'6" ,AREA 6 |
| 2793 | SV3-4031-SHW-861536 | FABRICATE AND INSTALL CABLE TRAY SUPPORTS ANNEX BLDG. AREA 1, ELEV. 100¿, BETWEEN COLUMN LINES 11.15/13 & E/F. |
| 2794 | SV3-RNS-PHW-861491 | FABRICATION/INSTALLATION OF RNS LARGE BORE PIPE SUPPORTS FOR ISO SV3-RNS-PLW-175 |
| 2795 | SV3-2131-CSW-850091 | UNIT 3, TURBINE BUILDING, STAIR MODULE 2131-CS-91 |
| 2796 | SV3-4030-SSW-850011 | S01 Stair Tower |
| 2797 | SV4-CA20-S4W-CV5126 | UNIT 4 CA20 SA1 FLOOR INSTALLATION AT ELEV 92'-6" |
| 2798 | SV4-CA03-S4W-860189 | CA03 FloorLeak Chase Assembly |
| 2799 | SV4-1208-CCW-851005 | SV4 SHIELD BLDG COURSES 5&6 CONCRETE |
| 2800 | SV3-2047-SHW-861334 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 120' - 6", AREA 7, cOLUMNS 18 TO 19 & K.1 TO L.1 |
| 2801 | SV3-1230-C0W-850021 | AUX BUILDING WALL, CL 4.8, ELEV 107'-2" TO 117'-6" (WALL 95) |
| 2802 | SV3-HDS-PHW-860540 | INSTALLATION AND FABRICATION OF HDS SUPPORTS |
| 2803 | SV3-PXS-PHW-ME8739 | Fabrication/Installation of Pipe Supports for Isometric Drawing SV3-PXS-PLW-680 |
| 2804 | SV3-RNS-P0W-ME5055 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRICS SV3-RNS-PLW-181, SV3-RNS-PLW-180, & SV3-RNS-PLW-18A (LINE NUMBERS RNS-PL-L015, -L016, -017, L082), , |
| 2805 | SV3-RNS-P0W-ME5057 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC SV3-RNS-PLW-370 (LINE NUMBER RNS-PL-L047), , |
| 2806 | SV3-RNS-P0W-ME5058 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC SV3-RNS-PLW-380 (LINE NUMBER RNS-PL-L046), , |
| 2807 | SV4-ME2L-MEW-861645 | VYS HEAT EXCHANGERS |
| 2808 | SV3-ME01-P0W-860979 | INSTALLATION OF CONDENSER A HEATER DRAIN PIPING |
| 2809 | SV4-CA22-CAW-850001 | CA22 MODULE INSTALLATION |
| 2810 | SV4-2141-SSW-850000 | 117'-6" ELEV. STRUCTURAL STEEL |
| 2811 | SV4-2141-SPW-850000 | 117'-6" ELEV.DECKING/GRATING |
| 2812 | SV4-5030-C0W-850001 | UNIT 4 RADWASTE SUMP MUDMATS |
| 2813 | SV0-0000-XGW-CV0276 | Erosion Control - NOI 20 |
| 2814 | SV0-0000-XPW-CV0616 | Utility Trench Crossing |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2815 | SV0-847-SSW-TP1813 | MAB End Wall Removal And Re-Installation |
| 2816 | SV0-SDS-CCW-CV0156 | Grinder Pump/Lift Station Concrete Foundations |
| 2817 | SV0-SDS-CKW-ME1529 | Install Sanitary Drain Manholes SV0-SDS-MH-41, SV0-SDS-MH-43, SV0-SDS-MH-44, & SV0-SDS-MH-45 |
| 2818 | SV0-SDS-CKW-ME1530 | Rework SDS Manholes MH-46 and MH-47 |
| 2819 | SV0-SDS-CKW-ME1531 | INSTALL SANITARY DRAIN MANHOLE SV0-SDS-MH-42. |
| 2820 | SV3-1000-XEW-CV1907 | Unit 3 Power Block Excavation and Backfill of Utilities |
| 2821 | SV3-1200-CRW-CV1409 | Unit 3 Auxiliary Building Walls Elevation 66'-6" to 82'-6" Reinforcing Steel For Walls #21,22,23,& 24 |
| 2822 | SV3-1200-CRW-CV1413 | UNIT 3 AUXILIARY BUILDING EL 66-6 TO 82-6 REBAR FOR WALLS 8, 9, 10, 11, 12, 13, 14, 16, 17, AND 18. |
| 2823 | SV3-1210-CEW-CV1260 | UNIT 3 AUXILIARY BUILDING-EL. 66'6" EMBED PLATES FOR CONCRETE WALL PLACEMENT #2 |
| 2824 | SV3-CAS-PHW-ME1033 | Fabrication/Installation of Pipe Supports for Isometric Drawing CAS-PLW-773 |
| 2825 | SV3-CAS-PLW-ME0928 | Fabricate and Install Small Bore Elevation 1 DWS Piping Iso SV3-DWS-PLW-773 |
| 2826 | SV3-CDS-PLW-ME2304 | INSTALLATION OF CDS PIPING FOR ISOMETRIC SV3-CDS-PLW-01AR, SV3-CDS-PLW-01AQ, SV3-CDS-PLW-01AP, SV3-CDS-PLW-013 SPOOL #1-4. |
| 2827 | SV4-1000-CCW-850000 | Unit 4 Outside The CVBH Concrete Placement X from Elev. 82'-6" to 94'-0" |
| 2828 | SV3-2052-SHW-861860 | INSTALLATION OF CABLE TRAY WELDED SUPPORTS IN TURBINE BUILDING (ELEV. 141' 3" AREA 2) |
| 2829 | SV3-CA33-S5W-862270 | CA33 OLP'S AND EMBEDMENT PLATES |
| 2830 | SV3-ME01-PHW-860973 | CONDENSER A HEATER DRAIN PIPE SUPPORTS |
| 2831 | SV4-WLS-P0W-861960 | FABRICATION/INSTALLATION OF WLS PIPING SHOWN ON ISOMETRIC DRAWINGS SV4-WLS-PLW-35C, -215, -376, -380 AND -904 |
| 2832 | SV4-ASS-PHW-860317 | INSTALLATION AND FABRICATION OF AUXILLIARY STEAM SYSTEM(ASS) PIPING SUPPORT |
| 2833 | SV4-CDS-P0W-860328 | INSTALLATION OF CDS PIPING (PORTION 3) |
| 2834 | SV3-1210-CEW-CV1073 | UNIT 3 AUXILIARY BUILDING EL 66FT. 6IN. EMBED PLATES FOR CONCRETE WALL PLACEMENTS #1 & #4 |
| 2835 | SV3-1210-CEW-CV1261 | UNIT 3 AUXILIARY BUILDING-EL. 66'-6" EMBED PLATES FOR CONCRETE WALL PLACEMENTS #3, #11, #12, #13 (RM 12103), & #14 |
| 2836 | SV3-1210-CEW-CV1263 | UNIT 3 AUXILIARY BUILDING-EL. 66'-6" EMBED PLATES FOR CONCRETE WALL PLACEMENTS #6, #19, & #20 |
| 2837 | SV3-1210-CEW-CV1264 | UNIT 3 AUXILIARY BUILDING-EL. 66'-6" EMBED PLATES FOR CONCRETE WALL PLACEMENTS #7, #8, #9, #10, #13 (ROOM 12104), #15, #16, #17, & #18 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2838 | SV3-1210-EGW-EL1067 | Unit 3 Auxillary Bldg EL.66'-6" Grounding Work Package for Walls 4, 5 |
| 2839 | SV3-CAS-PHW-ME1034 | Fabrication/Installation of Pipe Supports for Isometric Drawing CAS-PLW-839 |
| 2840 | SV3-CAS-PLW-ME0927 | Fabricate and Install Small Bore Elevation CAS Piping Iso SV3-CAS-PLW-773 |
| 2841 | SV4-ME01-PHW-861875 | UNIT 4 CONDENSER B: INSTALLATION OF PIPING HANGERS & SUPPORTS FOR 1ST EXTRACTION STEAM PIPING |
| 2842 | SV3-CCS-PHW-ME1056 | Fabrication/Installation of Pipe Supports for Isometric Drawing CCS-PLW-750 |
| 2843 | SV3-CVS-PHW-ME1057 | Fabrication/Installation of Pipe Supports for Isometric Drawing CVS-PLW-07J |
| 2844 | SV3-CWS-PLW-ME0550 | UNIT 3 CWS (HDPE) PIPING FROM NUCLEAR ISLAND TO COOLING TOWER |
| 2845 | SV3-KB14-KBW-ME0452 | INSTALLATION OF MODULE KB14 - WGS EQUIPMENT & VALVES |
| 2846 | SV3-RNS-MPW-ME0752 | RNS-MP-01A Set & Anchor |
| 2847 | SV3-RNS-MPW-ME0753 | RNS-MP-01B Set & Anchor |
| 2848 | SV3-WLS-PHW-ME0835 | FABRICATION/INSTALLATION OF SMALL BORE WLS PIPING SUPPORTS FOR ISOMETRICS SV3-WLS-PLW-35C, -35K |
| 2849 | SV3-WLS-PHW-ME1042 | Fabrication/ Installation of Pipe Supports for Isometric Drawing WLS-PLW-045 |
| 2850 | SV3-WLS-PHW-ME1092 | Fabrication /Installation of Pipe Supports for Isometric Drawing WLS-PLW-750 |
| 2851 | SV3-WLS-PLW-ME0854 | Fabricate and Install WLS Embedded Piping shown on Isometric Drawing SV3-WLS-PLW-730 |
| 2852 | SV3-WLS-PLW-ME0871 | Fabricate and Install WLS Piping ISO SV3-WLS-PLW-071 |
| 2853 | SV3-WLS-PLW-ME0873 | Fabricate and Install WLS Piping Isometrics SV3-WLS-PLW-741 and SV3-WLS-PLW-74A |
| 2854 | SV3-WLS-PLW-ME0940 | Fabricate and Install Small Bore Elevation 71'-6" WLS Piping Iso SV3-WLS-PLW-64P and 64Q |
| 2855 | SV3-WRS-P0W-ME4422 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES ISOMETRICS SV3-WRS-PLW-800, -86G, -86H |
| 2856 | SV3-WRS-PLW-ME0606 | INSTALLATION OF LARGE BORE WRS PIPING (INCLUDES ISOMETRICS SV3-WRS-PLW-52A, -52B, -52D, -52F) |
| 2857 | SV3-WWS-PHW-ME0782 | INSTALLATION OF LARGE BORE WWS PIPING SUPPORTS (INCLUDES ISOMETRICS SV3-WWS-PLW-321) |
| 2858 | SV4-1000-CEW-CV1478 | UNIT 4 NUCLEAR ISLAND BASEMAT -EL 66'-6" EMBEDDED PLATES & ANCHOR BOLTS-AREA 3 & 4 |
| 2859 | SV4-1000-CEW-CV1479 | UNIT 4 NUCLEAR ISLAND BASEMAT - EL 66'-6" EMBEDDED PLATES & ANCHOR BOLTS-AREA 5 & 6 |
| 2860 | SV4-1000-CRW-CV1414 | UNIT 4 NUCLEAR ISLAND BOOT CLEANING STATION |
| 2861 | SV4-ME01-MEW-ME1192 | INSTALLATION OF UNIT 4 CONDENSERS A, B, AND C FOUNDATION |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2862 | SV4-ME01-PHW-861871 | UNIT 4 CONDENSER A: INSTALLATION OF PIPING HANGERS & SUPPORTS FOR 1ST EXTRACTION STEAM PIPING |
| 2863 | SV3-2053-SHW-861195 | ELECTRICAL CABLE TRAY WELDED SUPPORT INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 141'3", AREA 3 |
| 2864 | SV4-ME01-PHW-861879 | UNIT 4 CONDENSER C: INSTALLATION OF PIPING HANGERS & SUPPORTS FOR 1ST EXTRACTION STEAM PIPING |
| 2865 | SV4-FPS-P0W-860895 | FABRICATION AND INSTALLATION OF FPS PIPING ON ELEVATION 100' |
| 2866 | SV4-ME01-PHW-861722 | UNIT 4 CONDENSER B: FABRICATION & INSTALLATION O CASING DRAIN PIPING SUPPORTS |
| 2867 | SV4-PXS-P0W-851016 | INSTALL SV4 RING 2 PIPE ISOMETRIC SV4-PXS-PLW-948 |
| 2868 | SV4-RNS-P0W-861620 | ASME III FABRICATION/INSTALLATION OF CA20 LARGE BORE PIPING FOR ISOMETRIC SV4-RNS-PLW-141 |
| 2869 | SV3-PWS-P0W-861754 | INSTALLATION OF ANNEX BLDG PWS PIPING (ISO SV3-PWS-P0W-127 & 472) |
| 2870 | SV4-ME01-PHW-861721 | UNIT 4 CONDENSER A: FABRICATION & INSTALLATION OF CASING DRAIN PIPING SUPPORTS |
| 2871 | SV4-ME01-PHW-861723 | UMIT 4 CONDENSER C: FABRICATION & INSTALLATION OF CASING DRAIN PIPING SUPPORT |
| 2872 | SV3-2070-C0W-850012 | 230'-9" ELEV. FLOOR SLAB, POUR #2 |
| 2873 | SV4-2141-SAW-850000 | UNIT 4, FIRST BAY, 117'-6" ELEV., STUD INSTALLATION |
| 2874 | SV4-CA20-CAW-850100 | CA20 CLEAN-OUT PORT |
| 2875 | SV3-2070-C0W-850011 | 230'-9" ELEV. FLOOR SLAB, POUR # 1 |
| 2876 | SV3-1208-C0W-850009 | UNIT 3 CYLINDRICAL WALL - POUR RC09 |
| 2877 | SV3-CA20-EGW-860962 | Module CA20 Unit 3, EL. 66¿-6¿- 92¿-6¿, Install Grounding to Waste Holdup Tanks, Chemical Waste Tank, and Monitor Tank. |
| 2878 | SV4-1208-CCW-851001 | UNIT 4 SHIELD BUILDING PLACEMENT 13M AND SC COURSE 1 CONCRETE FILL |
| 2879 | SV4-WLS-PHW-861342 | INSTALLATION OF WLS PIPE SUPPORTS FOR ISOMETRICS SV4-WLS-PLW-33A & 870 |
| 2880 | SV4-ME01-PHW-861881 | UNIT 4 CONDENSER C: INSTALLATION OF PIPING HANGERS & SUPPORTS FOR 3RD EXTRACTION STEAM PIPING |
| 2881 | SV4-ME01-PHW-861872 | UNIT 4 CONDENSER A: INSTALLATION OF PIPING HANGERS & SUPPORTS FOR 2ND EXTRACTION STEAM PIPING |
| 2882 | SV4-ME01-PHW-861873 | UNIT 4 CONDENSER A: INSTALLATION OF PIPING HANGERS & SUPPORTS FOR 3RD EXTRACTION STEAM PIPING |
| 2883 | SV4-4030-C0W-850004 | 100' Elev. Walls, Pour # 4 |
| 2884 | SV3-4000-SHW-862348 | FABRICATION AND INSTALLATION OF TYPICAL FIELD ROUTED CONDUIT SUPPORTS, DETAIL C-50, ANNEX BUILDING, ALL AREAS/ELEVATIONS. BOOK 1 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2885 | SV3-4000-SHW-862349 | FABRICATION AND INSTALLATION OF TYPICAL FIELD ROUTED CONDUIT SUPPORTS, DETAIL C-50A, ANNEX BUILDING, ALL AREAS/ELEVATIONS. BOOK 1 |
| 2886 | SV3-4000-SHW-862350 | FABRICATION AND INSTALLATION OF TYPICAL FIELD ROUTED CONDUIT SUPPORTS, DETAIL C-52, ANNEX BUILDING, ALL AREAS/ELEVATIONS. BOOK 1 |
| 2887 | SV4-ME01-PHW-861874 | UNIT 4 CONDENSER A : INSTALLATION OF PIPING HANGERS & SUPPORTS FOR 4TH EXTRACTION STEAM PIPING |
| 2888 | SV4-RNS-P0W-861687 | ASME III FABRICATION/INSTALLATION OF CA20 LARGE BORE PIPING FOR ISOMETRIC SV4-RNS-PLW-097 |
| 2889 | SV4-RNS-P0W-861630 | ASME III FABRICATION/INSTALLATION OF CA20 LARGE BORE PIPING FOR ISOMETRIC SV4-RNS-PLW-090 |
| 2890 | SV3-PXS-PHW-851941 | INSTALL ISOMETRIC SV3-PXS-PLW-941 LARGE BORE PIPE SUPPORTS |
| 2891 | SV4-PXS-P0W-851009 | INSTALL SV4 RING 2 PIPE ISOMETRIC SV4-PXS-PLW-936 |
| 2892 | SV4-PXS-P0W-851011 | INSTALL SV4 RING PIPE 2 ISOMETRIC SV4-PXS-PLW-938 |
| 2893 | SV4-PXS-P0W-851007 | INSTALL SV4 RING PIPE 2 ISOMETRIC SV4-PXS-PLW-934 |
| 2894 | SV4-PXS-P0W-851010 | INSTALL SV4 RING 2 PIPE ISOMETRIC SV4-PXS-PLW-937 |
| 2895 | SV4-PXS-P0W-851008 | INSTALL SV4 RING 2 PIPE ISOMETRIC SV4-PXS-PLW-935 |
| 2896 | SV4-PXS-P0W-851013 | INSTALL SV4 RING 2 PIPE ISOMETRIC SV4-PXS-PLW-945 |
| 2897 | SV4-1020-CEW-CV3356 | EMBEDS FOR ANNULUS TUNNEL AND SHIELD BUILDING |
| 2898 | SV3-2032-ERW-862171 | INSTALLATION OF CABLE TRAY RACEWAY IN THE UNIT 3 TURBINE BUILDING, ELEVATION 100', AREA 2 |
| 2899 | SV3-RNS-PHW-861485 | FABRICATION/INSTALLATION OF RNS LARGE BORE SUPPORTS FOR ISO SV3-RNS-PLW-17K |
| 2900 | SV4-ME01-PLW-861885 | UNIT 4 CONDENSER A: FABRICATION & INSTALLATION OF 3RD EXTRACTION STEAM PIPING |
| 2901 | SV4-ME01-PLW-861883 | UNIT 4 CONDENSER A: FABRICATION & INSTALLATION OF 1ST EXTRACTION STEAM PIPING |
| 2902 | SV4-ME01-PLW-861886 | UNIT 4 CONDENSER A: FABRICATION & INSTALLATION OF 4TH EXTRACTION STEAM PIPING |
| 2903 | SV3-CA20-C0W-850005 | CA20 FLOOR SLABS 38 - 51 |
| 2904 | SV3-4000-SHW-862353 | FABRICATION AND INSTALLATION OF TYPICAL FIELD ROUTED CONDUIT SUPPORTS, DETAIL C-58B, ANNEX BUILDING, ALL AREAS / ELEVATIONS. BOOK 1 |
| 2905 | SV3-1214-JCW-862424 | STAGE SAMPLE MONITOR PANEL (SV3-PSS-JL-01) IN ROOM 12152, AREA 4, ELEV. 66'-6" |
| 2906 | SV3-FPS-PHW-851521 | INSTALLATION OF PIPE SUPPORTS FOR ISO SV3-FPS-PLW-521 |
| 2907 | SV3-PCS-P0W-850054 | INSTALL LARGE BORE PIPE ISOMETRIC SV3-PCS-PLW-054 |
| 2908 | SV3-PXS-PHW-851932 | INSTALL ISOMETRIC SV3-PXS-PLW-932 LARGE BORE PIPE SUPPORTS |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2909 | SV3-PXS-PHW-852930 | INSTALL ISOMETRIC SV3-PXS-PLW-930 LARGE BORE PIPE SUPPORTS |
| 2910 | SV4-1220-C0W-862491 | INSTALLATION OF REBAR, EMBED PLATES, CONCRETE AND FORMWORK FOR U4 AUXILIARY BUILDING CONCRETE BEAMS AT ELEV 82'-6" |
| 2911 | SV3-CVS-P0W-860231 | INSTALLATION OF CVS PIPING ON MODULE KQ22 |
| 2912 | SV4-ME01-PHW-861882 | UNIT 4 CONDENSER C: INSTALLATION OF PIPING HANGERS & SUPPORTS FOR 4TH EXTRACTION STEAM PIPING |
| 2913 | SV4-MT71-C0W-850016 | Waste Water Retention Basin Wall Pour # 16 |
| 2914 | SV4-MT71-C0W-850018 | Waste Water Retention Basin Wall Pour # 18 |
| 2915 | SV4-ME01-PHW-861880 | UNIT 4 CONDENSER C: INSTALLATION OF PIPING HANGERS & SUPPORTS FOR 2ND EXTRACTION STEAM PIPING |
| 2916 | SV4-ME01-PHW-861878 | UNIT 4 CONDENSER B: INSTALLATION OF PIPING HANGERS & SUPPORTS FOR 4TH EXTRACTION STEAM PIPING |
| 2917 | SV3-4030-SSW-850014 | 100' ELEV. S04 STAIR |
| 2918 | SV4-ME01-PLW-861884 | UNIT 4 CONDENSER A: FABRICATION & INSTALLATION OF 2ND EXTRACTION STEAM PIPING |
| 2919 | SV4-ME01-PHW-861876 | UNIT 4 CONDENSER B: INSTALLATION OF PIPING HANGERS & SUPPORTS FOR 2ND EXTRACTION STEAM PIPING |
| 2920 | SV4-ME01-PHW-861877 | UNIT 4 CONDENSER B: INSTALLATION OF PIPING HANGERS & SUPPORTS FOR 3RD EXTRACTION STEAM PIPING |
| 2921 | SV3-4000-SHW-862351 | FABRICATION AND INSTALLATION OF TYPICAL FIELD ROUTED CONDUIT SUPPORTS, DETAIL C-56, ANNEX BUILDING, ALL AREAS/ELEVATIONS. BOOK 1 |
| 2922 | SV4-R151-R1W-862032 | R151 COMMODITY MODULE INSTALLATION |
| 2923 | SV4-ME01-MEW-862139 | UNIT 4 CONDENSER B: INSTALLATIONOF FEEDWATER HEATERS |
| 2924 | SV4-ME01-PHW-861719 | UNIT 4 CONDENSER B INSTALLATION OF VACUUM PIPING SUPPORTS |
| 2925 | SV4-ASS-PHW-860319 | INSTALLATION AND FABRICATION OF AUXILIARY STEAM SYSTEM(ASS) PIPING SUPPORT |
| 2926 | SV4-WRS-MTW-862030 | INSTALLATION OF LEAK CHASE POTS SV4-WRS-MT-02A / 02B |
| 2927 | SV4-ME01-MEW-862138 | UNIT 4 CONDENSER A: INSTALLATION OF FEEDWATER HEATERS |
| 2928 | SV4-CA04-S8W-CV4095 | U4 INSTALLATION OF CA04 MODULE AT ELEV. 71'-6 |
| 2929 | SV4-ME01-PHW-861718 | UNIT 4 CONDENSER A: INSTALLATION OF VACUUM PIPING SUPPORTS |
| 2930 | SV4-ME01-PHW-861720 | UNIT 4 CONDENSER C: INSTALLATION OF VACUUM PIPING SUPPORTS |
| 2931 | SV3-MH01-ASW-850001 | UNIT 3 CONTAINMENT- INITIAL POLAR CRANE RAIL INSTALLATION |
| 2932 | SV4-WWS-P0W-862362 | INSTALLATION AND FABRICATION OF WASTE WATER N(WWS) PIPING FOR SLAB 2 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2933 | SV4-ME01-MEW-862140 | UNIT 4 CONDENSER C: INSTALLATION OF FEEDWATER HEATERS |
| 2934 | SV3-MH20-MHW-861869 | 220T CRANE INITIALIZATION PACKAGE |
| 2935 | SV4-4041-AGW-800000 | Annex Building, Wall Insulation and Gypsum Board, 117'-6"' Elev., Rooms 40410,40411,40412 |
| 2936 | SV3-CDS-P0W-ME1392 | INSTALL LB CONDENSATE PIPING FROM CONDENSATE PUMPS TO CONDENSATE POLISHING SYSTEM |
| 2937 | SV3-CDS-PLW-ME2503 | INSTALLATION OF CDS PIPING FOR ISO'S SV3-CDS-PLW-100, -101, -102, -743, -910 |
| 2938 | SV3-ZAS-ERW-862234 | INSTALLATION OF CABLE TRAY SOUTH OF UNIT 3 TRANSFORMERS (24" AND 36") |
| 2939 | SV3-PXS-P0W-850941 | INSTALL ISOMETRIC SV3-PXS-PLW-941 LARGE BORE PIPING |
| 2940 | SV3-RNS-PHW-850162 | INSTALL LARGE BORE SUPPORTS FOR ISOMETRICS V3-RNS-PLW-162 |
| 2941 | SV3-SFS-MLW-861036 | ASME SECTION III - INSTALLATION OF CONTAINMENT VESSEL PENETRATION SV3-SFS-PY-C01 (P21) |
| 2942 | SV3-RNS-PHW-861874 | ASME SECTION III - FABRICATION/ INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-RNS-PLW-01B |
| 2943 | SV3-1221-SHW-861903 | INSTALL TYPE 01 CABLE TRAY SUPPORTS RM 12205 82'-6" UNIT 3 AUX |
| 2944 | SV4-CVS-P0W-861600 | INSTALLATION OF CVS PIPING IN ANNEX U4 |
| 2945 | SV3-PWS-PHW-861979 | INSTALLATION OF PWS PIPING SUPPORTS IN ANNEX 3 (PORTION 7) |
| 2946 | SV4-0000-C0W-850013 | TRANFORMER FOUNDATION WALL POUR #13 |
| 2947 | SV4-0000-C0W-850010 | TRANSFORMER FOUNDATION, TRANSFORMER PAD 10 |
| 2948 | SV4-CVS-PHW-861601 | INSTALLATION OF CVS PIPE SUPPORTS IN ANNEX U4 |
| 2949 | SV3-1212-ERW-EL4748 | AUXILARY BUILDING UNIT 3, EL 66'-6", AREA 2, FABRICATE AND INSTALL DESIGNED TRAY SUPPORTS |
| 2950 | SV3-MSS-P0W-ME4675 | INSTALLATION AND FABRICATION OF MAIN STEAM SYSTEM(MSS) PIPING |
| 2951 | SV3-HDS-PHW-860538 | FABRICATION AND INSTALLATION OF HDS SUPPORTS |
| 2952 | SV4-0000-C0W-850024 | TRANSFORMER FOUNDATION, WALL POUR #24 |
| 2953 | SV3-5030-C0W-850005 | UNIT 3 RADWASTE BUILDING, PIT FOUNDATIONS |
| 2954 | SV3-4051-C0W-850000 | UNIT 3, ANNEX BUILDING, 135' -3" ELEV. FLOOR SLAB, AREA 1 |
| 2955 | SV4-RNS-P0W-850186 | INSTALL LARGE BORE PIPE ISOMETRIC SV4-RNS-PLW-186 |
| 2956 | SV4-0000-C0W-850011 | TRANSFORMER FOUNDATION WALL POUR # 11 |
| 2957 | SV3-CA05-C0W-850000 | CA05 CONCRETE PRE-PLACEMENT AND PLACEMENT UP TO 105' - 2" |
| 2958 | SV3-1237-SHW-860292 | INSTALL CONDUIT SUPPORTS ON SHIELD WALL AZ 270¿ TO AZ-325¿ 100'-0" |

# Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2959 | SV4-WRS-PHW-861737 | KB13 INSTALLATION OF PIPE SUPPORTS & LEVEL TRANSMITTER MOUNT |
| 2960 | SV3-RNS-PHW-861880 | ASME SECTION III - FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-RNS-PLW-402 |
| 2961 | SV3-1230-C0W-850020 | WALL 97 (TOP TO 117') |
| 2962 | SV3-4033-ERW-862033 | INSTALLATION OF CONDUIT PENETRATION SLEEVES, ANNEX BUILDING, AREA 3, ELEV. 100'-0", 107'-2", 121'-0 ' & 126'-3" |
| 2963 | SV3-2052-ERW-861852 | ELECTRICAL CABLE TRAY RACEWAY FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEAVATION 141'-3" AREA 2 |
| 2964 | SV3-2052-ERW-861891 | ELECTRICAL CABLE TRAY RACEWAY FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 141'-3", AREA 2 |
| 2965 | SV3-2056-ERW-861930 | INSTALLATION OF CABLE TRAY RACEWAY IN THE UNIT 3 TURBINE BUILDING, ELEVATION 141' - 3", AREA 6 |
| 2966 | SV3-2053-SHW-862020 | ELECTRICAL CABLE TRAY SUPPORTS FABRICATION, AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 141' - 3", AREA 3 |
| 2967 | SV3-PXS-P0W-850932 | INSTALL ISOMETRIC SV3-PXS-PLW-932 LARGE BORE PIPING |
| 2968 | SV3-RNS-PHW-861873 | ASME SECTION III – FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-RNS-PLW-01A |
| 2969 | SV3-CA34-S5W-861655 | CA34 MODULE FABRICATION/ASSEMBLY OF LOOSE PARTS |
| 2970 | SV3-TDS-PHW-860614 | INSTALLATION AND FABRICATION OF TURBINE ISLAND VENTS DRAINS AND RELIEF SYSTEMS (TDS) PIPING SUPPORT |
| 2971 | SV3-CAS-P0W-ME3430 | INSTALLATION OF SMALL BORE CAS PIPING (INCLUDES SV3-CAS-PLW-33A) |
| 2972 | SV3-2070-MLW-862023 | INSTALLATION OF MECHANICAL PIPING PENETRATIONS ON ELEVATION 255' (ROOF) |
| 2973 | SV3-2070-MLW-862022 | INSTALLATION OF MECHANICAL PIPING PENETRATIONS ELEVATION 230' |
| 2974 | SV3-ML05-MLW-ME4785 | INSTALLATION OF 100'0" AREA 1 PIPING PENETRATIONS |
| 2975 | SV3-PWS-P0W-861978 | INSTALLATION OF PWS PIPING IN ANNEX 3 (PORTION 7) |
| 2976 | SV4-CA01-S4W-888358 | UNIT 4 CA01 B-PLATE FABRICATION |
| 2977 | SV3-2037-ERW-862158 | INSTALLATION OF ELECTRICAL CABLE TRAY RACEWAY IN THE UNIT 3 TURBINE BUILDING, EL. 100'-0" AREA 7 |
| 2978 | SV3-2044-SHW-861963 | ELECTRICAL CABLE TRAY TRAPEZE SUPPORTS |
| 2979 | SV3-2052-ERW-861890 | ELECTRICAL CABLE TRAY RACEWAY FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 141'-3", AREA 2 |
| 2980 | SV3-2048-ERW-862151 | INSTALLATION ON CABLE TRAY RACEWAY IN THE UNIT 3 TURBINE BUILDING ELEVAION 120'-6" |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 2981 | SV3-2052-ERW-861887 | ELECTRICAL CABLE TRAY RACEWAY FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 141'-3", AREA 2 |
| 2982 | SV3-2040-SHW-861920 | ELECTRICAL CABLE TRAY TRAPEZE SUPPORTS FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 120' - 6", AREA 0 |
| 2983 | SV3-RNS-PHW-861882 | ASME SECTION III - FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-RNS-PLW-422 |
| 2984 | SV4-MT71-C0W-850012 | Waste Water Retention Basin Wall Pour # 12 |
| 2985 | SV3-2052-ERW-861888 | ELECTRICAL CABLE TRAY RACEWAY FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 141'-3", AREA 2 |
| 2986 | SV4-0000-C0W-850012 | TRANSFORMER FOUNDATION, TRANSFORMER PAD POUR # 12 |
| 2987 | SV4-WLS-PHW-861523 | Fabrication/Installation of WLS Piping Supports shown on Isometric Drawings SV4-WLS-PLW-33K, -357 and -35F |
| 2988 | SV3-4032-SHW-EL4034 | INSTALL CABLE TRAY SUPPORTS ANNEX BLDG AREA 2, ROOMS 40355, 40354 & 40360 |
| 2989 | SV3-4032-SHW-EL4033 | INSTALL CABLE TRAY SUPPORTS ANNEX BLDG AREA 2, ROOM 40352 |
| 2990 | SV3-PXS-PHW-851943 | INSTALL ISOMETRIC SV3-PXS-PLW-943 LARGE BORE PIPE SUPPORTS |
| 2991 | SV3-1232-ERW-861442 | INSTALL CONDUIT SLEEVES FOR PENETRATIONS IN UNIT 3 AUX BUILDING FLOOR SLABS, EL 100'-0" AREA 2 RMS. 12312 & 12313 |
| 2992 | SV4-VAS-P0W-861614 | INSTALLATION OF PIPING FOR SV4-VAS-PLW-300, 310, -320 & -330 |
| 2993 | SV4-CA20-S4W-CV5121 | UNIT 4 CA20 MODULE BRACING, SHORING & FORMWORK |
| 2994 | SV4-4033-C0W-850000 | UNIT 4 ANNEX BUILDING CONCRETE PUMP TOWER FOUNDATION IN AREA 3 AT ELEV 100'-0" |
| 2995 | SV3-CA00-S5W-862198 | SV3-CA MODULES - COUPLER/REBAR ASSEMBLY FABRICATION |
| 2996 | SV4-4043-SPW-850001 | UNIT 4 - ANNEX, 126'3 " ELEV., DECKING INSTALLATION |
| 2997 | SV4-4030-CYW-850000 | 100' ELEV. GROUT, COLUMN BASES |
| 2998 | SV4-ME2G-MEW-862057 | FEEDWATER HEATERS SV4-FWS-ME-07A/B |
| 2999 | SV3-KQ10-KQW-ME0568 | KQ10 REACTOR COOLANT DRAIN TANK (WLS-MT-01) INSTALLATION |
| 3000 | SV3-CA20-C0W-850002 | CA20 FLOOR SLAB, 66 |
| 3001 | SV3-4030-SSW-850012 | 100'- ELEV. S02. STAIRS |
| 3002 | SV4-VAS-PHW-861615 | INSTALLATION OF PIPE SUPPORTS FOR SV4-VAS-PLW-300 & -320 |
| 3003 | SV3-5000-EGW-861864 | INSTALLATION OF RADWASTE BUILDING GROUNDING FOR AREAS 1, 2, & 3 AT THE 100'-0" ELEVATION |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3004 | SV3-2059-SHW-861056 | ELECTRICAL CABLE TRAY SUPPORT INSTALLATION IN THE TURBINE BUILDING, ELEVATION 141¿3¿ , AREA 9, ROOM 20500 (TRAPEZE) |
| 3005 | SV3-MSS-P0W-860794 | MAIN STEAM TURBINE BYPASS PIPING INSTALLATION |
| 3006 | SV3-1000-CYW-850000 | UNIT 3, NUCLEAR ISLAND BASE MAT REPAIR |
| 3007 | SV4-1000-CYW-850000 | UNIT 4, NUCLEAR ISLAND BASEMAT REPAIR |
| 3008 | SV3-PXS-PHW-851942 | INSTALL ISOMETRIC SV3-PXS-PLW-942 LARGE BORE PIPE SUPPORTS |
| 3009 | SV4-PXS-P0W-851012 | INSTALL SV4 RING PIPE ISOMETRIC SV4-PXS-PLW-944 |
| 3010 | SV3-PXS-PHW-851931 | INSTALL ISOMETRIC SV3-PXS-PLW-931 LARGE BORE PIPE SUPPORTS |
| 3011 | SV3-PXS-PHW-851940 | INSTALL ISOMETRIC SV3-PXS-PLW-940 LARGE BORE PIPE SUPPORTS |
| 3012 | SV4-5030-C0W-850000 | UNIT 4 RADWASTE BUILDING MUDMAT |
| 3013 | SV3-5030-ERW-861865 | INSTALLATION OF RADWASTE BUILDING CONDUIT FOR AREAS 1,2, & 3 AT THE 100' - 0" ELEVATION |
| 3014 | SV3-MSS-PHW-860570 | MAIN STEAM TURBINE BYPASS PIPE SUPPORTS |
| 3015 | SV3-WWS-P0W-860880 | FABRICATION AND INSTALLATION OF WWS PIPING AND PIPING DRAINS IN FIRST BAY |
| 3016 | SV3-WWS-P0W-861107 | INSTALLATION OF ANNEX BLDG WWS PIPING (ISO SV3-WWS-PLW-434, 435, 436, 476 & 967) |
| 3017 | SV3-2068-SHW-800003 | Install welded cable tray supports in turbin building (elevation 170'0" and 193'6" area 8) |
| 3018 | SV3-5030-C0W-850001 | UNIT 3 RADWASTE BUILDING SUMP MUDMATS |
| 3019 | SV3-5030-C0W-850000 | UNIT 3 RADWASTE BUILDING MUDMAT |
| 3020 | SV4-DWS-PHW-861603 | INSTALLATION OF ANNEX BLDG DWS PIPE SUPPORTS (ISO SV4-DWS-PLW-131) |
| 3021 | SV3-SFS-PHW-861791 | FABRICATION/INSTALLATION OF B31.1 SUPPORTS FOR ISOMETRIC SV3-SFS-PLW-780 |
| 3022 | SV3-EDS-DSW-EL3125 | INSTALL ANNEX BLDG. NON CLASS 1E DC AND UPS SYSTEM - DC BUS JUNCTION CABINET LOAD GROUP SPARE, ROOM 40310, |
| 3023 | SV3-EDS-DSW-EL3121 | INSTALL ANNEX BLDG. NON CLASS 1E DC AND UPS SYSTEM - LOAD GROUP SPARE, ROOM 40308, |
| 3024 | SV4-KB10-KBW-861732 | MODULE KB10 STRUCTURAL FABRICATION |
| 3025 | SV4-1212-ERW-861217 | INSTALL DESIGN ROUTED CABLE TRAY AND SUPPORTS FOR DIVISION "A" BATTERY ROOM 12101 EL. 66'-6" |
| 3026 | SV3-4031-ERW-861247 | Install Cable Tray in Rms 40307-40310 Annex Bldg. Area 1, Elev. 100¿ (WP7) |
| 3027 | SV3-HDS-PHW-ME3765 | INSTALLATION AND FABRICATION OF HEATER DRAIN SYSTEM(HDS) PIPING SUPPORTS. |
| 3028 | SV3-HDS-P0W-ME3740 | INSTALLATION AND FABRICATION OF HDS PIPING |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3029 | SV3-MSS-P0W-ME4653 | INSTALLATION OF MSS PIPING |
| 3030 | SV4-2000-P0W-861999 | INSTALLATION OF TEMPORARY FIRE PROTECTION SYSTEM STANDPIPE |
| 3031 | SV4-2000-PHW-862000 | INSTALLATION AND FABRICETION OF TEMPORARY FIRE PROTECTION PIPING SUPPORTS |
| 3032 | SV3-CA37-CAW-850000 | CA37 MODULE FABRICATION |
| 3033 | SV4-CB32-CBW-850000 | CB32 MODULE INSTALLATION |
| 3034 | SV4-MT71-C0W-850006 | Waste Water Retention Basin Wall Pour # 6 |
| 3035 | SV4-CB33-CBW-850000 | CB33 MODULE INSTALLATION |
| 3036 | SV4-2060-C0W-850000 | UNIT 4, TURBINE GENERATOR DECK. 170' ELEV |
| 3037 | SV3-WWS-PHW-ME6703 | WASTE WATER SYSTEM 140' ELEVATION |
| 3038 | SV4-MSS-PHW-860360 | INSTALLATION AND FABRICATION OF MAIN STEAM SYSTEM(MSS) PIPE SUPPORTS |
| 3039 | SV4-4030-C0W-850002 | 100'-0" ELEV. WALL, POUR #2 |
| 3040 | SV4-4030-C0W-850001 | 100'-0" ELEV. WALL, POUR #1 |
| 3041 | SV3-MV90-MVW-862062 | INSTALLATION OF WLS WASTE PRE-/AFTER MODULE (WLS-MV-06 AND 07 |
| 3042 | SV3-CA01-CCW-850001 | Unit 3 CA01 Concrete Placement, Walls #1 through #4 from Elev. 87'-6" to 146'-10-1/2" |
| 3043 | SV3-MV90-MVW-862061 | INSTALLATION OF DEMINERALIZER OUTLET FILTER ALPHA AND BRAVO (SFS-MV-02A AND 02B) |
| 3044 | SV3-ME2L-MEW-ME5893 | INSTALLATION OF VYS HEAT EXCHANGER (VYS-ME-01A/B) AT ELEVATION 120'-6" |
| 3045 | SV3-4050-C0W-850019 | UNIT 3- ANNEX CONCRETE WALLS, CENTRAL W10 WALL, POUR #19 |
| 3046 | SV3-HDS-P0W-ME3739 | INSTALLATION AND FABRICATION OF HDS PIPING |
| 3047 | SV3-1232-ERW-861441 | INSTALL CONDUIT SLEEVES FOR PENETRATIONS IN UNIT 3 AUX BUILDING FLOOR SLABS, EL 100'-0" AREA 2 RMS. 12301, 12302, 12303 & 12311 |
| 3048 | SV3-CVS-PHW-ME0808 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-CVS-PLW-506 |
| 3049 | SV4-WWS-P0W-862031 | INSTALLATION AND FABRICATION OF WASTE WATER (WWS) SYSTEM PIPING FOR SLAB 2 |
| 3050 | SV3-2101-C0W-850402 | 122' ELEV WALLS, POUR 2NE |
| 3051 | SV3-2101-C0W-850403 | 122' ELEV WALLS, POUR 2NW |
| 3052 | SV3-MSS-PHW-ME4674 | INSTALLATION AND FABRICATION OF MAIN STEAM SYSTEM(MSS) PIPING SUPPORT |
| 3053 | SV3-2101-C0W-850401 | 122' ELEV. WALLS, POUR 2SE |
| 3054 | SV3-HDS-PHW-ME3754 | TURBINE BUILDING HDS PIPE SUPPORT INSTALLATION |
| 3055 | SV3-2101-C0W-850404 | 122' Elev., Walls, Pour2SW |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3056 | SV3-MSS-PHW-ME4684 | INSTALLATION AND FABRICATION FO MAIN STEAM SYSTEM(MSS) PIPING SUPPORTS |
| 3057 | SV3-PXS-P0W-ME2951 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-410 (LINE NUMBERS PXS-PL-L121A), , |
| 3058 | SV3-RNS-PHW-861881 | ASME SECTION III – FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-RNS-PLW-411 |
| 3059 | SV3-PXS-P0W-850940 | INSTALL ISOMETRIC SV3-PXS-PLW-940 LARGE BORE PIPING |
| 3060 | SV3-RNS-PHW-861877 | ASME SECTION III – FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-RNS-PLW-021 |
| 3061 | SV0-SES-ERW-EL1842 | INSTALLATION OF ELECTRICAL UNDERGROUND COMMODITIES (MANHOLES AND DUCT BANKS) FOR THE (SES) PLANT SECURITY SYSTEM EAST OF THE ANNEX BLDG. - PHASE 1 |
| 3062 | SV0-ZFS-ERW-EL1797 | INSTALLATION OF UNDERGROUND COMMODITIES (MANHOLES AND DUCTBANKS) FOR THE (EFS/ZFS) COMMUNICATIONS SYSTEM FROM THE ANNEX BLDG. TO MANHOLE NZM026 - PHASE 1 |
| 3063 | SV3-0000-EGW-EL2236 | PERFORM INSTALLATION OF UNDERGROUND COMMODITIES (EGS-GROUNDING) FOR THE TRANSFORMER AREA, ELEV. 100' |
| 3064 | SV4-MT2Y-MEW-861646 | HDS LOW PRESSURE DRAIN TANKS (MT-04A/B/C) |
| 3065 | SV3-MSS-PHW-ME4693 | INSTALLATION OF MSS PIPE SUPPORTS |
| 3066 | SV4-WRS-P0W-861604 | INSTALLATION OF ANNEX BLDG WRS PIPING (ISO SV4-WRS-PLW-411, 412, 413, 414, 420, 421 & 430 |
| 3067 | SV4-2030-SHW-861086 | INSTALLATION OF TURBINE 4 CABLE TRAY SUPPLEMENTARY STEEL ON THE 100'-0" ELEVATION AREAS 0, 1 & 4, FROM COLUMNS K.1 TO R AND 12.1 TO 14. |
| 3068 | SV3-2043-SHW-861331 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 120'-6", AREA 3, COLUMNS 18 TO19 & P.2 TO R |
| 3069 | SV3-RNS-PHW-861878 | ASME SECTION III - FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-RNS-PLW-190 |
| 3070 | SV3-CB00-S5W-CV2819 | INSTALLATION OF SHEAR STUD FOR CB MODULES |
| 3071 | SV3-ME01-PLW-ME1534 | UNIT 3 CONDENSER B: INSTALLATION OF WATER CURTAIN PIPING |
| 3072 | SV3-SWS-PLW-ME1484 | INSTALLATION OF SWS LARGE BORE PIPING (INCLUDES ISOMETRICS SV3-SWS-PLW-010, 020) |
| 3073 | SV3-CA32-CAW-850000 | Unit 3, CA32 Module Fabrication |
| 3074 | SV3-SGS-P0W-ME6693 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC SV3-SGS-PLW-070 (LINE NUMBERS SGS-PL-L009A) |
| 3075 | SV3-2042-SHW-861327 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 120' - 6", AREA 2, SOUTH OF COLUMN 18 & P.1 TO R |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3076 | SV3-4040-AMW-850001 | MASONRY WALLS, SWITCH GEAR ROOM 40414 AND 40413 |
| 3077 | SV3-1200-C0W-850002 | S02 STAIR TOWER TREADS, CONCRETE PLACEMENT |
| 3078 | SV3-WWS-C0W-850001 | UNIT 3 WWs OIL SEPARATOR, RETAINING WALLS AND EQUIP PADS POUR #1 |
| 3079 | SV4-WWS-C0W-850001 | UNIT 4, WWS OIL SEPARATOR, RETAINING WALLS AND EQUIP PADS POUR #1 |
| 3080 | SV3-CA36-S5W-861650 | CA36-Module Fabrication/Assembly of Loose parts |
| 3081 | SV4-1212-ERW-861219 | INSTALL DESIGN ROUTED CABLE TRAY AND SUPPORTS FOR DIVISION "C" BATTERY ROOM 12102 EL. 66'-6" |
| 3082 | SV3-4050-C0W-850020 | UNIT 3, ANNEX CONCRETE WALLS, W09 AND NORTH W10 WALLS, POUR #20 |
| 3083 | SV4-0000-C0W-850009 | Transformer Foundation, Wall Pour # 9 |
| 3084 | SV4-2060-SSW-850013 | TB13 STEEL ERECTION |
| 3085 | SV3-PXS-PHW-862100 | AMSE SECTION III - FABRICATION/ INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-PXS-PLW-740 |
| 3086 | SV3-RNS-PHW-861886 | ASME SECTION III - FABRICATION/ INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-RNS-PLW-014 |
| 3087 | SV3-PXS-P0W-851930 | INSTALL ISOMETRIC SV3-PXS-PLW-930 LARGE BORE PIPING |
| 3088 | SV3-PXS-P0W-850930 | INSTALL ISOMETRIC SV3-PXS-PLW-93A SMALL BORE PIPING |
| 3089 | SV3-PXS-P0W-850949 | INSTALL ISOMETRIC SV3-PXS-PLW-949 SMALL BORE PIPING |
| 3090 | SV3-PXS-P0W-850931 | INSTALL ISOMETRIC SV3-PXS-P0W-850931 |
| 3091 | SV4-SFS-P0W-850757 | INSTALL ASME PIPE FROM ISOMETRIC SV4-SFS-PLW-757 |
| 3092 | SV3-1212-ERW-EL4749 | AUXILARY BUILDING UNIT 3, EL 66'-6", AREA 2, FABRICATE AND INSTALL DESIGNED TRAY SUPPORTS |
| 3093 | SV3-CVS-PHW-ME3336 | INSTALLATION OF BORIC ACID CVS PIPING SUPPORTS FOR WP (SV3-CVS-P0W-ME3327). |
| 3094 | SV3-RNS-P0W-850017 | INSTALL ISOMETRIC SV3-RNS-PLW-17A |
| 3095 | SV4-RNS-PHW-861621 | ASME III FABRICATION/INSTALLATION OF CA20 PIPE SUPPORTS FOR ISOMETRIC SV4-RNS-PLW-141 |
| 3096 | SV3-PXS-P0W-862101 | ASME SECTION III – FABRICATION/INSTALLATION OF PIPING FOR ISOMETRIC SV3-PXS-PLW-012 |
| 3097 | SV4-RNS-PHW-861624 | ASME III FABRICATION/INSTALLATION OF CA20 PIPE SUPPORTS FOR ISOMETRICS SV4-RNS-PLW-210 & -214 |
| 3098 | SV3-2131-SHW-862185 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE UNI 3 TURBINE BUILDING, FIRST BAY AREA1. EL. 100'-0", COLUMNS 11 TO 12.1 AND COLUMNS P.2 TO R. |
| 3099 | SV3-2131-SHW-862187 | ELECTRICAL CABLE TRAY SUPPLEMENTAL TRAY STEEL INSTALLATION IN THE UNIT 3 TURBINE BUILDING, FIRST BAY AREA 1, EL. 100'-0", COLUMNS 11 TO 12.1 AND WEST OF 1.2 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3100 | SV3-2053-SHW-861210 | Electrical Cable Tray Welded (floor stand) Support Installation in the Unit 3 Turbine Building, Elevation 141'3", Area 3 |
| 3101 | SV3-FPS-P0W-850055 | INSTALL LARGE BORE PIPE PER ISO SV3-FPS-PLW-55MM |
| 3102 | SV3-TDS-P0W-861539 | INSTALLATION AND FABRICATION OF TURBINE ISLAND DRAINS VENTS AND REFLIEF SYSTEM(tds)PIPING |
| 3103 | SV4-1212-ERW-861220 | INSTALL DESIGN ROUTED CONDUIT AND CONDUIT SUPPORTS IN BATTERY ROOM "C", ROOM 12102 EL. 66¿-6¿ |
| 3104 | SV3-2131-SHW-862186 | ELECTRICAL CABLE TRAY SUPPLEMENT STEEL INSTALLATION IN THE UNIT 3 TURBINE BUILDING FIRST BAY AREA 1, EL. 100'-0", COLUMNS 11 TO 12.1 AND COLUMNS K.5 TO L.5 |
| 3105 | SV4-1212-ERW-861222 | INSTALL DESIGN ROUTED CONDUIT AND CONDUIT SUPPORTS IN "SPARE" BATTERY ROOM 12103 EL. 66¿ |
| 3106 | SV3-WWS-P0W-ME6281 | WWS PIPING TO THE UNIT 3 WASTE WATER RETENTION BASIN |
| 3107 | SV3-PWS-PHW-862040 | INSTALLATION OF ANNEX BLDG PWS PIPE SUPPORTS (ISO SV3-PWS-PLW-111, 112, 116, 142, 143, 145, 151, 152, 441 & 459) |
| 3108 | SV3-MH20-MHW-861870 | 15T Crane Initialization Package |
| 3109 | SV3-4000-SHW-862352 | FABRICATION AND INSTALLATION OF TYPICAL FIELD ROUTED CONDUIT SUPPORTS, DETAIL C-58A, ANNEX BUILDING, ALL AREAS/ELEVATIONS, BOOK 1 |
| 3110 | SV3-PWS-P0W-862039 | INSTALLATION OF ANNEX BLDG PWS PIPING (ISO SV3-PWS-PLW-111, 112, 116, 142, 143, 145, 151, 152, 441 & 459 |
| 3111 | SV4-RNS-P0W-861667 | ASME III FABRICATION/INSTALLATION OF CA20 LARGE BORE PIPING FOR ISOMETRIC SV4-RNS-PLW-17C |
| 3112 | SV3-PXS-P0W-850942 | INSTALL ISOMETRIC SV3-PXS-PLW-942 LARGE BORE PIPING |
| 3113 | SV3-PCS-P0W-850810 | INSTALL PIPING PER ISO SV3-PCS-PLW-810 |
| 3114 | SV3-1214-JCW-862429 | STAGE GRAB SAMPLE PANEL PACKAGE (SV3-PSS-MS-01) IN ROOM 12152M AREA 4, ELEV. 66'-6" |
| 3115 | SV0-SES-ERW-862488 | INSTALL CONDUIT IN SES DUCT BANK/TRENCH FOR SECURITY LOCATED BETWEEN SITE GRID J1603-K1402 |
| 3116 | SV4-1120-EJW-861993 | FABRICATION AND INSTALLATION OF EX-CORE DETECTOR PMS JUNCTION BOX SUPPORTS IN ROOMS 11202 & 1104 EL 84'-6" |
| 3117 | SV4-PWS-P0W-800001 | Install Small Bore Pipe & Supports Per SV4-PWS-PLW-053 |
| 3118 | SV3-ZBS-EWW-861313 | Cable Pull from Switchyard Control House to Unit 3 Turbine |
| 3119 | SV4-CA01-CCW-850004 | CA01 CONCRETE WALL PLACEMENT SEC 6 A, B, C, & D AND 9 |
| 3120 | SV3-CA01-CCW-850004 | CA01 CONCRETE WALL PLACEMENT SEC 6 A, B, C, & D AND 9 |
| 3121 | SV4-PWS-P0W-862369 | INSTALLATION OF ANNEX BLDG PWS PIPING (ISO SV4-PWS-PLW-115, - 457 & -458 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3122 | SV4-CAS-PHW-800001 | Install Small Bore Supports per Isometric SV4-CAS-PLW-839 |
| 3123 | SV3-VWS-PLW-ME2798 | INSTALL PIPING FOR IS0 #'S SV3-VWS-PLW-20K, SV3-VWS-PLW-20L, SV3-VWS-PLW-20M. |
| 3124 | SV3-2151-SSW-800000 | First Bay, 135'-3" Elev. Structural Steel |
| 3125 | SV3-FPS-PHW-851055 | INSTALL PIPE SUPPORTS FOR ISO SV3-FPS-PLW-55M |
| 3126 | SV4-MT71-C0W-850015 | Waste Water Retnetion Basin Wall Pour # 15 |
| 3127 | SV4-MT71-C0W-850017 | Waste Water Retention Basin Wall Pour # 17 |
| 3128 | SV3-1222-CSW-850100 | S01 STAIR TOWER FOR NI 3, AUX BUILD, AREA 2 |
| 3129 | SV4-RNS-P0W-861628 | ASME III FABRICATION/INSTALLATION OF CA20 SMALL BORE PIPING FOR ISOMETRICS SV4-RNS-PLW-211, -216 & -218 |
| 3130 | SV3-PCS-P0W-850833 | INSTALL ASME III LB PIPING FROM ISOMETRIC SV3-PCS-PLW-833 |
| 3131 | SV3-PCS-P0W-850830 | INSTALL ISOMETRIC SV3-PCS-PLW-830 |
| 3132 | SV4-RNS-PHW-861629 | ASME III FABRICATION/INSTALLATION OF CA20 PIPE SUPPORTS FOR ISOMETRICS SV4-RNS-PLW-211 & -216 |
| 3133 | SV3-PXS-P0W-850933 | INSTALL ISOMETRIC SVE-PXS-PLW-933 LARGE BORE PIPING |
| 3134 | SV3-PWS-P0W-862367 | INSTALLATION OF ANNEX BLDG PWS PIPING (ISO SV3-PWS-PLW-115, -457 & 458 |
| 3135 | SV3-HDS-P0W-860763 | INSTALLATION AND FABRICATION OF HDS PIPING |
| 3136 | SV4-CA20-C0W-850003 | CA20 FLOOR SLABS 34 thru 37 |
| 3137 | SV3-4040-AMW-850003 | MASONRY WALLS, ROOMS 40412 AND 40411 |
| 3138 | SV3-CDS-PHW-860479 | INSTALLATION OF CDS PIPING SUPPORTS |
| 3139 | SV3-WWS-PHW-860657 | FABRICATION AND INSTALLATION OF WWS PIPING SUPPORTS |
| 3140 | SV3-WWS-PHW-860656 | FABRICATION AND INSTALLATION OF WWS PIPING HANGERS |
| 3141 | SV3-1000-TIW-862440 | BIG SPAN CV COVER TEMPORARY ELECTRICAL |
| 3142 | SV3-WWS-PHW-861108 | Installation of Annex WWS Piping Supports |
| 3143 | SV4-WLS-PHW-861363 | INSTALLATION OF PIPE SUPPORTS FOR ISOMETRICS SV4-WLS-PLW-33D & 33E |
| 3144 | SV4-WLS-PHW-861361 | INSTALLATION OF PIPE SUPPORTS FOR ISOMETRICS SV4-WLS-PLW-980 & -981 |
| 3145 | SV3-40302-AEW-800000 | Architectural Ceiling System, Room 40302 |
| 3146 | SV4-2020-ERW-861800 | INSTALLATION OF CABLE TRAY RACEWAY ON THE 82'-9" ELEVATION OF THE TURBINE BUILDING |
| 3147 | SV3-2037-ERW-862159 | INSTALLATION OF ELECTRICAL CABLE TRAY RACEWAY IN THE UNIT 3 TURBINE BUILDING, EL. 100'-0" AREA 7 |
| 3148 | SV4-CB41-CBW-800000 | CB41 Module Installation |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3149 | SV4-CB37-CBW-800000 | CB37 Module Installation |
| 3150 | SV4-CB43-CBW-800000 | CB43 Module Installation |
| 3151 | SV4-1130-C0W-800001 | Reinforced Concrete inside Containment, Reactor Cavity, from 87'-6" to 98'-0" Elev. |
| 3152 | SV4-1130-C0W-800002 | Reinforced Concrete inside Containment, Refuel Cavity up to 95' Elev. |
| 3153 | SV3-PCS-P0W-850051 | INSTALL PIPE ISOMETRIC SV3-PCS-PLW-051 LARGE BORE PIPE |
| 3154 | SV4-ME01-PLW-861889 | UNIT 4 CONDENSER B: FABRICATION & INSTALLATION OF 3RD EXTRACTION STEAM PIPING |
| 3155 | SV4-ME01-PLW-861887 | UNIT 4 CONDENSER B: FABRICATION & INSTALLATION OF 1ST EXTRACTION STEAM PIPING |
| 3156 | SV4-0000-ELW-862490 | INSTALLATION OF CONDUIT FOR UNIT 4 STANDARD PLANT YARD TRANSFORMER AREA LIGHTING |
| 3157 | SV4-2060-EGW-862155 | EMBEDDED GROUNDING INSTALLATION FOR TURBINE 4 AT ELEVATIONS 148'-10", 158'-7" AND 170'-0" |
| 3158 | SV4-0000-ELW-862487 | CABLE PULL AND FIXTURES FOR UNIT 4 STANDARD PLANT TRANSFORMER AREA LIGHTING |
| 3159 | SV3-FPS-P0W-850521 | INSTALL LARGE BORE FPS PIPING ISO SV3-FPS-PLW-521 |
| 3160 | SV4-ME01-PLW-861890 | UNIT 4 CONDENSER B: FABRICATION & INSTALLATION OF 4TH EXTRACTION STEAM PIPING |
| 3161 | SV4-RNS-P0W-861697 | ASME III FABRICATION/INSTALLATION OF CA20 LARGE BORE PIPING FOR ISOMETRIC SV4-RNS-PLW-173 |
| 3162 | SV4-RNS-PHW-861678 | ASME III FABRICATION/INSTALLATION FO PIPE SUPPORTS FOR SV4-RNS-PLW-17S |
| 3163 | SV4-RNS-PHW-861703 | ASME III FABRICATION/INSTALLATION OF CA20 PIPE SUPPORTS FOR ISOMETRIC SV4-RNS-PLW-176 |
| 3164 | SV3-R261-ERW-862645 | INSTALLATION OF ELECTRICAL CABLE TRAY AND TRAY GROUNDING IN MODULE R261 |
| 3165 | SV3-SGS-MLW-861041 | ASME SECTION III - INSTALLATION OF CONTAINMENT VESSEL PENETRATION SV3-SGS-PY-C03A (P27) |
| 3166 | SV3-SGS-MLW-861042 | ASME SECTION III - INSTALLATION OF CONTAINMENT VESSEL PENETRATION SV3-SGS-PY-C03B (P28) |
| 3167 | SV3-FPS-P0W-854200 | INSTALL SPOOLS FOR SV3-FPS-PLW-55A, 55B, 55C, 559, 55U, 558, 55X, 55T, 556 |
| 3168 | SV3-4031-SHW-861532 | FABRICATE AND INSTALL CABLE TRAY SUPPORTS ANNEX BLDG. AREA 1, ELEV. 100¿, WEST OF BATTERY CHARGER ROOMS, BETWEEN COLUMN LINES 9/10.05. |
| 3169 | SV3-5030-C0W-850006 | UNIT 3 RADWASTE BUILDING, REBAR FABRICATION FOR GRADE BEAMS & TRENCHES |
| 3170 | SV4-ME01-PLW-862149 | UNIT 4 CONDENSER B TO C INTERCONNECTION PIPING |
| 3171 | SV4-0000-C0W-850025 | TRANSFORMER MSU PEDESTAL |
| 3172 | SV4-1208-C0W-800011 | 100'-0" - Cylindrical Wall - RC02 |
| 3173 | SV3-CA33-S5W-862273 | CA33- SEAM WELDS |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3174 | SV3-WWS-PHW-860658 | INSTALLATION OF WWS PIPE SUPPORTS |
| 3175 | SV3-RNS-PHW-861875 | ASME SECTION III – FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-RNS-PLW-013 |
| 3176 | SV3-CA33-S5W-862462 | CA33 MODULE - INSTALL SHIPPED LOOSE PARTS |
| 3177 | SV3-WLS-P0W-ME3726 | INSTALLATION OF LARGE BORE WLS PIPING (ISOMETRICS SV3-WLS-PLW-534,-535,-536,-53A) |
| 3178 | SV4-WLS-PHW-861367 | INSTALLATION OF PIPE SUPPORTS FOR ISOMETRICS SV4-WLS-PLW-35L, -35K, -35M & -90B |
| 3179 | SV3-2042-SHW-861328 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE UNIT 3 TURBINE BUILDING AREA 2, EL. 120'-6", NORTH OF COLUMN 17 AND BETWEEN COLUMNS P.1 TO R |
| 3180 | SV4-MT71-C0W-850014 | Waste Water Retention Basin Wall Pour # 14 |
| 3181 | SV4-1160-SPW-800000 | SPL22, 23 & 24 Installation |
| 3182 | SV4-WRS-P0W-800005 | Install Large Bore Pipe per Isometric SV4-WRS-PLW-59P |
| 3183 | SV3-WSS-PHW-ME4397 | FABRICATION/INSTALLATION OF SMALL BORE WSS PIPING SUPPORTS (INCLUDES ISOMETRICS SV3-WSS-PLW-510, 511, 512) |
| 3184 | SV3-CA01-CCW-850002 | CA01 Concrete, Wall Placements #2 through #4 from Elev. 146'-10-1/2" to 153'-0", and #17 and #18 to Elev. 158'-0" |
| 3185 | SV4-WRS-P0W-800006 | Install Large Bore Pipe per Isometric SV4-WRS-PLW-59Y |
| 3186 | SV4-1208-CCW-851002 | UNIT 4 SHIELD BUILDING COURSE 2 CONCRETE FILL |
| 3187 | SV4-CA20-C0W-850009 | 90'-3" & 92'-6" ELEV CA20 FLOOR SLABS, CA20-43 THRU 46 FLOORS, ROOM 12463 & 12365 |
| 3188 | SV3-2131-SHW-800004 | Electrical Cable Tray Supports Turbine Building First Bay Elevation 100'0" Area 1 |
| 3189 | SV4-RNS-PHW-861666 | ASME III FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR SV4-RNS-PLW-17B |
| 3190 | SV4-PXS-PHW-851021 | INSTALL SV4 RING 2 SUPPORTS FROM PIPE ISOMETRIC SV4-PXS-PLW-938 |
| 3191 | SV3-4031-AWW-850000 | UNIT 3 - ANNEX BUILDING, WALL FRAMING, 100' EL., ROOMS 40300 AND 40302 |
| 3192 | SV3-4051-ERW-862397 | INSTALLATION OF CONDUIT PENETRATION SLEEVES, ANNEX BUILDING, AREA 1, ELEV. 135'-3" |
| 3193 | SV3-CA01-CCW-850013 | UNIT 3 CA01 CONCRETE WALL PLACEMENT SECTION #16 UP TO 116'-6" |
| 3194 | SV3-2058-SHW-800000 | Elec Cable Tray Welded Support Fab & Install in Unit 3 Turbine Building, Elevation 141’ 3”, Area 8 |
| 3195 | SV4-RNS-P0W-800003 | Install LB Pipe from ISO SV4-RNS-PLW-17F |
| 3196 | SV4-CAS-P0W-800002 | Install small bore pipe and supports per SV4-CAS-PLW-86C |
| 3197 | SV4-2070-C0W-850005 | ROOF ELE. FLOOR SLAB, POUR #5 |
| 3198 | SV3-1208-C0W-850007 | UNIT 3 CYLINDRICAL WALL - POUR RC07A |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3199 | SV4-CA20-S4W-850005 | CA20, ROOMS 12362 & 12363, SUBMODULE 52, 53, 54 & 55 INSTALLATION |
| 3200 | SV3-2131-SHW-800006 | Electrical Cable Tray Supports Turbine Building First Bay Elevation 100'0" Area 1 |
| 3201 | SV4-RNS-PHW-861626 | ASME III FABRICATION/INSTALLATION OF CA20 PIPE SUPPORTS FOR ISOMETRIC SV4-RNS-PLW-161 |
| 3202 | SV4-1208-CEW-800000 | 100'-0" - Cylindrical Wall - Fabricate Electrical EPA's |
| 3203 | SV4-1235-EYW-862722 | INSTALL CONDUIT SLEEVES FOR PENETRATIONS THROUGH PRECAST CONCRETE PANEL 1225-CP-S01 UNIT 4 AUXILIARY BUILDING ELEVATION 81'-6" AREA 5 |
| 3204 | SV4-PXS-P0W-860287 | INSTALL LARGE BORE PIPING ISOMETRICS (SV4-PXS-PLW-187, -188, -189) |
| 3205 | SV4-DWS-P0W-860989 | INSTALL SMALL BORE DWS PIPING and SUPPORTS (ISOMETRIC: SV4-DWS-PLW-772) |
| 3206 | SV4-DWS-P0W-860297 | INSTALL SMALL BORE DWS PIPING and SUPPORTS (INCLUDES ISOMETRICS: SV4-DWS-PLW-770, -771) |
| 3207 | SV4-DWS-P0W-862430 | INSTALL SMALL BORE DWSPIPING AND SUPPORTS (INCLUDES ISOMETRICS: SV4-DWS-PLW-771) |
| 3208 | SV3-4041-AWW-850000 | UNIT 3- ANNEX BUILDING, WALL FRAMING, 117-6' ELEV, ROOMS 40410, 40411, 40412 |
| 3209 | SV4-WLS-PHW-850750 | FABRICATE AND INSTALL SUPPORTS FOR ISO SV4-WLS-PLW-750 |
| 3210 | SV4-2060-SAW-862812 | UNIT 4 TURBINE BUILDING 170'-0" ELEVATION STUD INSTALLATION |
| 3211 | SV3-1208-C0W-850017 | UNIT 3 CYLINDRICAL WALL - POUR RC07B |
| 3212 | SV3-2131-SHW-800008 | Electrical Cable Tray Supports Turbine Building First Bay Elevation 100'0" Area 1 |
| 3213 | SV4-4051-SAW-850001 | SUPPLEMENTARY STEEL EL135'-3" AREA 1 GL E/I.1 & 11.09/11.15 |
| 3214 | SV4-1211-ERW-861223 | INSTALL DESIGN ROUTED CABLE TRAY AND SUPPORTS FOR DIVISION "B" BATTERY ROOM 12104 EL. 66'-6" |
| 3215 | SV3-2031-SHW-800000 | Installation of Welded Cable Tray Supports in Turbine Building (Elev. 100’ 3” Area 1) |
| 3216 | SV4-4030-C0W-850007 | UNIT 4 ANNEX BUILDING REINFROCING STEEL FOR AREA 1 WALLS FROM ELEV. 100'-0" TO 117'-6" |
| 3217 | SV3-CA02-CCW-850000 | UNIT 3 CONTAINMENT WALL MODULE CA02 CONCRETE PLACEMENT |
| 3218 | SV4-2050-CCW-862816 | UNIT 4 TURBINE BUILDING GROUTING ACTIVITIES AT ELEVATION 141'-3" |
| 3219 | SV4-0000-C0W-850026 | TRANSFORMER FOUNDATION MSU NORTH WALLS |
| 3220 | SV4-WRS-P0W-861736 | INSTALLATION OF WRS PIPING ON MODULE KB13 |
| 3221 | SV3-CA37-ERW-861472 | FABRICATION AND INSTALLATION OF ELECTRICAL PENETRATIONS WITHIN THE CA37 MODULE |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3222 | SV3-TDS-PHW-860618 | INSTALLATION AND FABRICATION OF TURBINE ISLAND VENTS AND DRAINS AND RELIEF SYSTEMS (TDS) PIPING SUPPORTS |
| 3223 | SV3-PWS-PHW-861414 | INSTALLATION OF PWS PIPE SUPPORTS |
| 3224 | SV4-RNS-PHW-861690 | ASME III FABRICATION/INSTALLATION OF CA20 PIPE SUPPORTS FOR ISOMETRIC SV4-RNS-PLW-142 |
| 3225 | SV4-RNS-PHW-861674 | ASME III FABRICATION/INSTALLATION OF CA20 PIPE SUPPORTS FOR ISOMETRIC SV4-RNS-PLW-17Q |
| 3226 | SV4-CA01-S4W-861775 | CA01-SA07 - ELEV. 107' - 119' DIRECT WELDED ATTACHMENTS (DWA) |
| 3227 | SV3-2042-SHW-861329 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE UNIT3 TURBINE BUILDING, ELEVATION 120'-6", AREA 2, COLUMNS 16 TO 17 & BETWEEN P.1 TO R |
| 3228 | SV3-2044-SHW-860224 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE UNIT3 TURBINE BUILDING, ELEVATION 120'-6", AREA 4, COLUMNS 13.05 TO 13.1 & BETWEEN I.2 TO K.1 |
| 3229 | SV3-2070-EGW-861658 | ELECTRICAL GROUNDING FOR UNIT 3 TURBINE BUILDING ROOF, AREA ROOF, ELEVATION 254'-0" |
| 3230 | SV3-1130-C0W-850009 | CONCRETE PRE-PLACEMENT & PLACEMENT IN THE UNIT 3 CONTAINMENT TOC EL. 107'-2" |
| 3231 | SV3-11206-CYW-800000 | Grout PXS Accumulator Tank, 87'-6" Elev., Room 11206 |
| 3232 | SV3-11207-CYW-800000 | Grout PXS Accumulator Tank B, Room 11207 |
| 3233 | SV4-4030-C0W-850008 | UNIT 4 ANNEX BUILDING EMBEDMENTS AND CONCRETE FOR AREA 1 WALLS FROM ELEV 100'-0" TO 117'-6" |
| 3234 | SV4-1130-C0W-850000 | REINFORCED CONCRETE INSIDE CONTAINMENT 87'-6" TO 96'-0" WEST SIDE (LAYER 6V AND 7V) |
| 3235 | SV3-1121-JRW-855000 | INSTALL INSTRUMENT RACK 1121-JR-001 |
| 3236 | SV4-CA02-CCW-850000 | UNIT 4 CONTAINMENT WALL MODULE CA02 CONCRETE PLACEMENT |
| 3237 | SV3-HDS-P0W-ME3738 | INSTALLATION AND FABRICATION OF HEATER DRAIN SYSTEM PIPING |
| 3238 | SV3-2131-SHW-800003 | Electrical Cable Tray Supports Turbine Building First Bay Elevation 100'0" Area 1 |
| 3239 | SV3-2056-SHW-800001 | Elect Cable Tray Welded Support Fab & Install in Unit 3 Turbine Building, Elevation 141’ 3”, Area 6 |
| 3240 | SV4-2000-C0W-862917 | Unit 4 Turbine Building 100'-0" Elev. Temporary Elevator Foundation |
| 3241 | SV4-WWS-P0W-862177 | INSTALL ISO SV4-WWS-PLW-437, 438, 439, 441, 442 AND 443 |
| 3242 | SV3-CA35-S5W-862208 | CA35 ASSEMBLY AND SHIP LOOSE MATERIAL INSTALL |
| 3243 | SV4-RNS-PHW-861631 | ASME III FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR SV4-RNS-PLW-090 |
| 3244 | SV4-RNS-PHW-861696 | ASME III FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR SV4-RNS-PLW-172 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3245 | SV4-PXS-PHW-851019 | INSTALL SV4 RING 2 SUPPORTS FROM PIPE ISOMETRIC SV4-PXS-PLW-936 |
| 3246 | SV4-PXS-PHW-851025 | INSTALL SV4 RING 2 SUPPORT FROM PIPE ISOMETRIC SV4-PXS-PLW-947 |
| 3247 | SV3-1123-JRW-862534 | ERECT INSTRUMENT RACK 1123-JR-001 |
| 3248 | SV4-12155-CYW-800000 | Room 12155 Grout, R155 - WLS Equipment Room Supply Balancing Damper |
| 3249 | SV4-12162-CYW-800000 | Room 12162 Grout, RNS Residual Heat Removal Pump A Stand (RNS-MZ-12A) |
| 3250 | SV4-12163-CYW-800000 | Room 12163 Grout, RNS Residual Heat Removal Pump B Stand (RNS-MZ-12B) |
| 3251 | SV4-2060-CEW-862913 | UNIT 4 TURBINE BUILDING 170'-0" ELEVATION PENETRATION SLEEVES |
| 3252 | SV3-PXS-P0W-862102 | ASME SECTION III - FABRICATION/INSTALLATION OF PIOPING FOR ISOMETRIC SV3-PXS-PLW-022 |
| 3253 | SV4-RNS-P0W-861623 | ASME III FABRICATION/INSTALLATION OF CA20 SMALL BORE PIPING FOR ISOMETRICS SV4-RNS-PLW-210, -214 & -217 |
| 3254 | SV4-PXS-P0W-850410 | INSTALL PIPE FOR IS0-PXS-PLW-410 |
| 3255 | SV4-RNS-PHW-861701 | ASME III FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR SV4-RNS-PLW-175 |
| 3256 | SV4-1208-C0W-850103 | 92'-6" TO 100'-0" ELEV, CONCRETE PRE-PLACEMENT AND PLACEMENT, POUR #12S |
| 3257 | SV4-WWS-P0W-862179 | INSTALLATION OF ANNEX BLDG WWS PIPING (ISO SV4-WWS-PLW-419, 420, 421, 422, 423, 424, 440, 470, 471, 472, 473, 474, 475 & 950) |
| 3258 | SV4-WWS-PHW-862180 | INSTALLATION OF ANNEX BLDG WWS PIPE SUPPORTS (WWS-PLW-419, 420, 421, 422, 423, 424, 440, 470, 471, 472, 473, 474, 475 & 950) |
| 3259 | SV4-1208-C0W-850101 | UNIT 4 CYLINDRICAL WALL, POUR # 11A ELEV 90'-6" TO 100'-0" |
| 3260 | SV4-1208-C0W-850102 | 90'-6" TO 100'-0" ELEV CONCRETE PRE-PLACEMENT AND PLACEMENT POUR # 12N |
| 3261 | SV4-4051-SAW-850000 | Unit 4, Annex Supplemental Steel Area 1, Elev 135'3" |
| 3262 | SV3-2141-ERW-862700 | THE INSTALLATION OF CONDUIT PENETRATION SLEEVES IN THE 117'6" ELEV WALLS OF THE FIRST BAY |
| 3263 | SV4-2053-SHW-862446 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE TURBINE BUILDING, ELEVATION 141'-3", AREA 3 FROM COLUMNS 19 TO 20 & P.2 TO R |
| 3264 | SV4-ME01-PLW-862141 | UNIT 4 CONDENSER A: INSTALLATION OF FLASHBOX PIPING |
| 3265 | SV4-FPS-PHW-860893 | INSTALLATION AND FABRICATION OF FIRE PROTECTION SYSTEM(FPS) PIPING SUPPORT |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3266 | SV3-2052-ERW-861892 | ELECTRICAL CABLE TRAY RACEWAY FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 141'-3", AREA 2 |
| 3267 | SV3-2053-ERW-861866 | ELECTRICAL CABLE TRAY RACEWAY FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 141'3", AREA 3 |
| 3268 | SV3-2053-ERW-861825 | SV3-2053-ERW-861825 |
| 3269 | SV3-2053-ERW-861824 | ELECTRICAL CABLE TRAY RACEWAY FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 141'3", AREA 3 |
| 3270 | SV3-2053-ERW-861867 | ELECTRICAL CABLE TRAY RACEWAY FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 141'3", AREA 3 |
| 3271 | SV3-2053-ERW-861865 | ELECTRICAL CABLE TRAY RACEWAY FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING ELEVATION 141'3" AREA 3 |
| 3272 | SV3-2053-ERW-861949 | ELECTRICAL CABLE TRAY RACEWAY FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING ELEVATION 141'3", AREA 3 |
| 3273 | SV3-0000-EGW-EL2315 | PERFORM INSTALLATION OF UNDERGROUND COMMODITIES (SV3-SITE STATION GROUNDING GRID) FOR GROUND GRID AREA, K1400. |
| 3274 | SV3-ASS-PLW-ME1476 | FABRICATE AND INSTALL AUXILIARY STEAM SYSTEM(ASS) PIPING PORTION 4 FOR 100-0 |
| 3275 | SV3-CA01-S4W-CV4224 | CA01-38 SUBMODULE ERECTION |
| 3276 | SV3-CA01-S4W-CV4237 | CA01 TEMPORARY ATTACHMENTS |
| 3277 | SV3-CA01-V1W-CV5039 | U3 INSTALLATION AND REMOVAL OF CA01 MODULE GUIDE PINS AT ELEV. 83'-0" |
| 3278 | SV3-CA05-S4W-CV3013 | INSTALLATION OF OPEN WORK ITEMS FOR CA05 MODULE TO BE INSTALLED AFTER SET AT NUCLEAR ISLAND NI 3. |
| 3279 | SV4-2000-SUW-CV1819 | CH80 MODULE ASSEMBLY & ERECTION |
| 3280 | SV0-YFS-P0W-ME1884 | FABRICATE AND INSTALL THE YARD FIRE WATER PIPING FROM THE BLDG. 301 CAPPED FUTURE SNC CONNECTION TO VISITOR CENTER. |
| 3281 | SV3-1220-CCW-CV1890 | CONCRETE IN AUXILIARY BUILDING WALLS (21,22,23, AND 24) UP TO ELEVATION 82'-6" |
| 3282 | SV3-1220-CEW-CV1608 | U3 AUXILIARY BUILDING EMBED PLATES &TEMPOARY FORMWORK-AREA 3 & 4-EL 82'-6" WALLS (WALL PLACEMENTS #28,41,42,48,49,51,& 52) |
| 3283 | SV3-1220-CRW-CV2575 | UNIT 3 AUXILIARY BUILDING A3 (82'-6" TO 100'-0") INTERIOR WALL REBAR - AREAS 3, 4, 5, &6 |
| 3284 | SV3-1220-SSW-CV1591 | Auxiliary Building Structural Steel Framing Elevation 82'-6" |
| 3285 | SV3-2101-CCW-CV3347 | UNIT 3 TURBINE FIRST BAY WALLS |
| 3286 | SV3-4000-SSW-CV2708 | RE-WORK ANNEX BUILDING AREA 4 STRUCTURAL STEEL |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3287 | SV3-4000-T2W-CV2231 | HSB ASSEMBLY & INSTALLER QUALIFICATION FOR ANNEX BUILDING AREAS 1-3 |
| 3288 | SV3-4001-SSW-CV3904 | Annex Building Area 1 Supplemental Steel Installation |
| 3289 | SV3-4002-SSW-CV3869 | ANNEX BUILDING AREA 2 SUPPLEMENTARY STEEL INSTALLATION |
| 3290 | SV3-4040-SSW-CV2286 | ANNEX BUILDING STRUCTURAL STEEL AREA 1 SEQUENCE |
| 3291 | SV3-4040-SSW-CV2287 | ANNEX BUILDING STRUCTURAL STEEL AREA 2 SEQUENCE |
| 3292 | SV3-CA01-S4W-CV2152 | INSTALL CA01-08 PERMANENT WELDED ATTACHMENTS |
| 3293 | SV3-CA01-S4W-CV2154 | INSTALL CA01-10 PERMANENT WELDED ATTACHMENTS |
| 3294 | SV3-CA01-S4W-CV2155 | CA01-SUB-ASSEMBLY 1 BASEMAT CONNECTION PLATES |
| 3295 | SV3-CA01-S4W-CV2245 | INSTALL CA01-28 PERMANENT WELDED ATTACHMENTS |
| 3296 | SV3-CA01-S4W-CV2246 | INSTALL CA01-29 PERMANENT WELDED ATTACHMENTS |
| 3297 | SV3-CA01-S4W-CV2941 | CA01-01 OVERLAY PLATES AND ATTACHMENTS |
| 3298 | SV3-CA01-S4W-CV3697 | CA01-03 OVERLAY PLATES AND ATTACHMENTS |
| 3299 | SV3-CA01-S4W-CV4075 | CA01-04 OLP'S AND PERMANENT WELDED ATTACHMENTS |
| 3300 | SV3-CA01-S4W-CV4078 | CA01-13 OLPs AND PERMANENT WELDED ATTACHMENTS |
| 3301 | SV3-CA01-S4W-CV4081 | CA01-17 OLP AND ATTACHMENTS |
| 3302 | SV3-CA01-S4W-CV4082 | CA01-18 Overlay Plates and Permanent Welded Attachments |
| 3303 | SV3-CA01-S4W-CV4151 | CA01 SUBASSEMBLY 2 BASEMAT CONNECTION PLATES |
| 3304 | SV3-CA01-S4W-CV4233 | INSTALL ACCESSIBLE CA01 SUB-ASSEMBLY 3 BASEMAT CONNECTION PLATES IN MAB |
| 3305 | SV3-CA01-S4W-CV4234 | CA01-SUB ASSEMBLY _4 Basemat Connection Plates |
| 3306 | SV3-CA01-S4W-CV4235 | SUB ASSEMBLY 5 ACCESSIBLE BASEMAT CONNECTION PLATE INSTALLATION IN MAB |
| 3307 | SV3-CA01-S4W-CV4236 | SUB ASSEMBLY 6 BASEMENT CONNECTION, ACCESSIBLE B-PLATE INSTALLATION IN MAB |
| 3308 | SV3-CA01-S4W-CV4278 | INSTALL CA01-38 PERMANENT WELDED ATTACHMENTS |
| 3309 | SV3-CA01-S4W-CV4284 | INSTALL SV3-CA01-25,-47 & -48 PERMANENT WELDED ATTACHMENTS |
| 3310 | SV3-CA01-S4W-CV5581 | CA01 OVERLAY PLATES - TORQUEING AND TESTING |
| 3311 | SV3-CA01-S4W-CV5692 | CA01-14 PERMANANT WELDED ATTACHMENTS |
| 3312 | SV3-CA01-S5W-CV4146 | CA01 MISCELLANEOUS UNSATISFACTORY IRS AND N&D REWORK/REPAIRS |
| 3313 | SV3-CA04-S5W-CV3778 | REWORK N&D SV3-CA04-GNR-000033 FOR UNIT 3 CA04 |
| 3314 | SV3-CA20-S4W-CV2075 | EXTERIOR TEMPORARY ATTACHMENTS @ COLUMN LINE 2 |
| 3315 | SV3-CA20-S4W-CV2077 | EXTERIOR TEMPORARY ATTACHMENTS @ COLUMN LINE J1 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3316 | SV3-CA20-S4W-CV2106 | INTERIOR TEMPORARY ATTACHMENTS FOR SUB-ASSEMBLY 1 |
| 3317 | SV3-CA20-S4W-CV2107 | INTERIOR TEMPORARY ATTACHMENTS FOR SUB-ASSEMBLY 2 |
| 3318 | SV3-CA20-S4W-CV2198 | CA20 SUB ASSEMBLY 1 REWORK FOR CLOSURE OF N&Ds |
| 3319 | SV3-CA20-S4W-CV2325 | CA20 SUB ASSEMBLY 2 WORK LIST ITEMS WB-W00003, WB-W00004, WB-W00017, WB-W00023, WB-W00031, WB-W00038, WB-W00042, WB-W00043 & WB-W00044 |
| 3320 | SV3-CA20-S4W-CV2560 | CA20 MODULE WALL BRACING FOR CONCRETE PLACEMENT |
| 3321 | SV3-CA20-S4W-CV2599 | CA20 WLS MONITOR TANKS MODIFICATIONS PER APP-CA20-GEF-1266 |
| 3322 | SV3-CA20-S5W-CV1501 | CA20 Installation of Rebar Couplers Removed for Testing |
| 3323 | SV3-CA20-S8W-CV2878 | INSTALL COMMODITIES IN CA20 MODULE FROM ELEVATION 82'6" TO 92'6" FOR ROOMS 12166, 12167, 12262, 12264, 12265 AND 12268 |
| 3324 | SV3-CB00-S8W-CV3227 | INSTALLATION OF CB MODULES 61, 62, 63 & 64 AT ELEVATION 80'0 |
| 3325 | SV3-R151-ERW-EL3772 | INSTALLATION OF ELECTRICAL CABLE TRAY IN MODULE R151 |
| 3326 | SV3-R155-ERW-EL2805 | INSTALLATION OF ELECTRICAL CABLE TRAY IN MODULE R155 |
| 3327 | SV3-SDS-PHW-ME2548 | INSTALLATION OF ANNEX SDS SUPPORTS (FOR WP SV3-SDS-P0W-ME2421) |
| 3328 | SV3-WWS-PHW-ME3044 | INSTALLATION OF WWS PIPE SUPPORTS FOR SLAB 3 AT 120' 6" ELEVATION PORTION 2 |
| 3329 | SV3-CVS-P0W-ME2661 | INSTALLATION OF SMALL BORE CVS PIPING (INCLUDES ISOMETRIC: SV3-CVS-PLW-802) |
| 3330 | SV3-CVS-P0W-ME2824 | INSTALLATION OF LARGE BORE CVS PIPING (INCLUDES ISOMETRICS: SV3-CVS-PLW-011) |
| 3331 | SV3-CVS-P0W-ME2827 | Installation of Large Bore CVS Piping (Includes Isometrics: SV3-CVS-PLW-195) |
| 3332 | SV3-CVS-PHW-ME2921 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-CVS-PLW-04J |
| 3333 | SV3-CVS-PHW-ME2927 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-CVS-PLW-290 |
| 3334 | SV3-CVS-PHW-ME2928 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-CVS-PLW-292 |
| 3335 | SV3-CVS-PHW-ME2929 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-CVS-PLW-800 |
| 3336 | SV3-CWS-P0W-ME2179 | FABRICATION AND INSTALLATION OF CWS PIPING FROM STRAINERS SV3-CWS-PY-C01A/B/C TO HEAT EXCHANGERS SV3-TCS-ME-01A/B/C. |
| 3337 | SV3-CWS-P0W-ME2197 | FABRICATION AND INSTALLATION OF CWS PIPING IN TURBINE ROOM 20309 FROM CWS HEADER TO CMS-ME-01A/B/C/D (ELEVATION 90FT TO 101 FT) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3338 | SV3-CWS-P0W-ME2214 | Farbrication And Installation of CWS Piping In Turbine Room 20309 From CWS Header To CMS-ME-01A/B/C/D (Elevation 101 FT To 129 FT) |
| 3339 | SV3-CWS-PHW-ME2180 | FABRICATION AND INSTALLATION OF CWS PIPING SUPPORTS FROM STRAINERS SV3-CWS-PY-C01A/B/C TO HEAT EXCHANGERS SV3-TCS-ME-01A/B/C. |
| 3340 | SV3-CWS-PLW-ME2505 | INSTALLATION OF CWS PIPING FOR ISOMETRICS SV3-CWS-PLW-737 |
| 3341 | SV3-DOS-EWW-EL2623 | INSTALL (PULL) ELECTRICAL LEAK DETECTION CABLES FOR THE (DOS) DIESEL OIL SYSTEM |
| 3342 | SV3-DOS-PHW-ME2312 | Install Pipe Supports (Spiders) on the Diesel Fuel Oil Lines East of Unit 3 Annex. |
| 3343 | SV3-DTS-PHW-ME1515 | Fabricate and Install Demineralized Water Treatment System (DTS) supports portion 1-(Raw Water Supply to DTS-MS-01) |
| 3344 | SV3-DTS-PLW-ME1514 | Fabricate and Install Demineralized Water Treatment System (DTS) piping (DTS-MT-02 DRAIN) |
| 3345 | SV3-DWS-P0W-ME2606 | FABRICATE AND INSTALL DWS SMALL BORE PIPING SHOWN ON THE ISOMETRIC DRAWING SV3-DWS-PLW-067 |
| 3346 | SV3-DWS-P0W-ME2607 | FABRICATE AND INSTALL DWS SMALL BORE PIPING SHOWN ON ISOMETRIC DRAWINGS SV3-DWS-PLW-732 & SV3-DWS-PLW-733 |
| 3347 | SV3-DWS-P0W-ME2608 | FABRICATE AND INSTALL DWS SMALL BORE PIPING SHOWN ON ISOMETRIC DRAWINGS SV3-DWS-PLW-755 & SV3-DWS-PLW-756 |
| 3348 | SV3-DWS-P0W-ME6351 | INSTALLATION OF ANNEX BLDG DWS PIPING (ISOMETRICS SV3-DWS-PLW-139 & -143 |
| 3349 | SV3-DWS-PHW-ME3339 | FABRICATE AND INSTALL DEMINERALIZED WATER PIPING SUPPORT IAW SV3-DWS-PLW-150, SV3-DWS-PLW-247 |
| 3350 | SV3-DWS-PHW-ME4473 | INSTALLATION OF ANNEX DWS PIPING SUPPORT FOR WP (SV3-DWS-P0W-ME4472) |
| 3351 | SV3-DWS-PHW-ME6675 | INSTALLATION OF ANNEX BLDG DWS PIPE SUPPORTS (ISOMETRICS SV3-DWS-PLW-140, -141) |
| 3352 | SV3-ECS-ERW-EL2717 | SV3- INSTALL ECS DUCT BANKS FROM MANHOLES NXM010, NXM011 TP FIRE PUMPS/ FIRE WATER TANKS- PHASE 3A |
| 3353 | SV3-ECS-ERW-EL2718 | SV3-INSTALL ECS DUCT BANKS FROM NORTH SIDE OF UNIT 3 TURBINE BLDG. TO CHEMICAL FEED STORAGE BLDG. - PHASE 3/4 |
| 3354 | SV3-ECS-ERW-EL2719 | SV3 - INSTALL ECS DUCT BANKS FROM SWS COOLING TOWERS TO PASSIVE CONTAINMENT COOLING TANK/DTS/WESTSIDE OF TURBINE BLDG. - PHASE 3/4 |
| 3355 | SV3-FPS-P0W-ME4957 | FABRICATE AND INSTALL THE UNIT 3 FIRE PROTECTION SYSTEM (FPS) PIPING ON ISOMETRICS (SV3-FPS-PLW-956, 957, 95AM, 95AN) |
| 3356 | SV3-FPS-P0W-ME6783 | FABRICATE AND INSTALL THE UNIT 3 FIRE PROTECTION SYSTEM (FPS) ON ISOMETRICS (SV3-FPS-PLW-958, 959, 95AQ, 95AS, 95AT) |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3357 | SV4-SWS-PLW-ME2362 | INSTALLATION OF SWS PIPING FOR ISOMETRICS SV4-SWS-PLW-040, SV4-SWS-PLW-041, SV4-SWS-PLW-042, SV4-SWS-PLW-043, |
| 3358 | SV4-SWS-PLW-ME2364 | INSTALLATION OF SWS PIPING FOR ISOMETRICS SV4-SWS-PLW-050, SV4-SWS-PLW-051, SV4-SWS-PLW-052, SV4-SWS-PLW-053, |
| 3359 | SV3-FPS-PHW-ME2474 | INSTALLATION OF ANNEX FPS PIPING SUPPORTS FOR WP (SV3-FPS-PLW-ME2471) |
| 3360 | SV3-FPS-PHW-ME2480 | INSTALLATION OF ANNEX FPS PIPING SUPPORTS FOR WP (SV3-FPS-PLW-ME2479) |
| 3361 | SV3-FPS-PHW-ME2577 | INSTALLATION OF ANNEX FPS PIPING SUPPORTS FOR WP (SV3-FPS-PLW-ME2574) |
| 3362 | SV3-FPS-PLW-ME2471 | INSTALLATION OF ANNEX FPS PIPING PACKAGE #1 |
| 3363 | SV4-WRS-PLW-ME1761 | INSTALLATION OF LARGE BORE WRS PIPING (INCLUDES ISOMETRICS SV4-WRS-PLW-59W, 593, 59E, 59F AND 59X) |
| 3364 | SV3-FPS-PLW-ME2479 | INSTALLATION OF ANNEX FPS PIPING PACKAGE #2 |
| 3365 | SV3-FPS-PLW-ME2573 | INSTALLATION OF ANNEX FPS PIPING PACKAGE #3 |
| 3366 | SV3-FPS-PLW-ME2574 | INSTALLATION OF ANNEX FPS PIPING PACKAGE #4 |
| 3367 | SV3-FPS-THW-ME2128 | HYDRO TEST PACKAGE FOR UNIT 3 PHASE 1 FIRE PROTECTION SYSTEM (FPS) |
| 3368 | SV3-1110-ADW-CV4326 | INSTALLATION OF RCDT COMPARTMENT REACTOR CAVITY SHIELD DOOR |
| 3369 | SV3-1120-CEW-CV5777 | U3 CONTAINMENT CONCRETE CA01 BASEMAT CONNECTION EMBED PLATES EL 87'-6" TO 107'-3" |
| 3370 | SV3-1210-ERW-EL3170 | AUXILARY BUILDING UNIT 3, EL 66'-6", AREA 6, INSTALL SCHEDULED CONDUIT AND TYPICAL SUPPORTS. |
| 3371 | SV3-1220-ERW-EL2744 | Conduit Sleeves, Unit 3 Auxiliary Building Floor Slab, Elevation 82'-6", Area 1 & 2 |
| 3372 | SV3-1220-ERW-EL3188 | INSTALL ELECTRICAL PENETRATIONS IN AUX BUILDING SHIELD WALL FROM 82'-6" TO 100'-0" |
| 3373 | SV3-1220-ERW-EL3285 | INSTALL ELECTRICAL CONDUIT SLEEVES IN UNIT 3 AUXILIARY BUILDING FLOOR SLAB, 82'-6", SECTION 2, IN ROOMS 12211 & 12212. |
| 3374 | SV3-1224-EYW-EL3326 | INSTALL CONDUIT SLEEVES FOR PENETRATIONS IN PRECAST CONCRETE PANEL. AND CAST-IN-PLACE CONCRETE (ABOVE PRECAST CONCRETE PANELS) UNIT 3, AUXILIARY BUILDING, ELEVATION 92'-6", AREA 4 |
| 3375 | SV3-1230-EGW-EL2883 | INSTALL GROUNDING GRID AND FLOOR PLATES FOR 100'-0" SLAB AREAS 1, 2 & 3 |
| 3376 | SV3-1230-EGW-EL2884 | INSTALL GROUNDING GRID AND FLOOR PLATES FOR 100'-0" SLAB AREAS 4, 5 & 6 |
| 3377 | SV3-1230-SSW-CV4311 | AUX BLD STRUCTURAL STEEL 82'-6" TO 100'-0" AREA 1 AND 2 |
| 3378 | SV3-2000-SSW-CV3088 | TURBINE BLDG. HOUSE STEEL IN-PROCESS REPAIR/REWORK (SEQ7-SEQ11) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3379 | SV3-2020-ERW-EL4488 | ELECTRICAL CABLE TRAY INSTALLATION FOR THE TURBINE BUILDING AT ELEVATION 82'-9" |
| 3380 | SV3-2033-SHW-EL6791 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE TURBINE BLDG, ELEV 100'-0" AREA 3 FROM COLUMNS 18 TO 19 & L.1 TO P.2 |
| 3381 | SV3-2038-SHW-EL6796 | Electrical Cable Tray Steel Installation in the Turbine Building, Elevation 100'-0", Area 8 from Colmns 12.1 to14 & H.05 to 1.2 |
| 3382 | SV3-2040-EGW-EL3352 | ELECTRICAL GROUNDING TERMINATIONS FOR THE UNIT # 3 TURBINE BUILDING AT ELEVATIONS 117'-6" AND 120'-6". |
| 3383 | SV3-2060-CEW-CV4838 | UNIT 3 TURBINE BLDG CA81 STEAM TURBINE GENERATOR FOUNDATION ANCHOR BOLT INSTALLATION AT EL. 170'-0" |
| 3384 | SV3-2060-SSW-CV7041 | TURBINE BLDG HOUSE STEEL IN-PROCESS REPAIR/REWORK (SEQUENCE 12 - SEQUENCE 16) |
| 3385 | SV3-2130-CCW-CV5214 | UNIT 3 TURBINE BUILDING FIRST BAY MISCELLANEOUS GROUTING AT ELEVATION 100'-0" |
| 3386 | SV3-2131-EYW-EL2912 | ELECTRICAL WALL PENETRATIONS FOR THE FIRST BAY TURBINE BUILDING AT ELEVATION 100'-0" |
| 3387 | SV3-4030-CCW-CV2187 | Annex Mat Foundation - Areas 1,2, & 3 |
| 3388 | SV3-ASS-P0W-ME4206 | FABRICATE AND INSTALL AUXILIARY STEAM SYSTEM(ASS) PIPING PORTION 5 FOR 100'-0" |
| 3389 | SV3-CA00-S4W-CV5035 | UNIT 3 NUCLEAR ISLAND SMCI OVERLAY PLATE COUPLER TENSILE TESTING FOR STRUCTURAL MODULES |
| 3390 | SV3-CA01-V2W-CV5875 | CA01 POST LOAD INSPECTIONS FOR SPARE SUPER LIFTING LUGS |
| 3391 | SV3-CA20-S4W-CV4395 | TEMPORARY ATTACHMENTS FOR CA20 FLOOR ASSEMBLIES |
| 3392 | SV3-CAS-PHW-ME2783 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWINGS SV3-CAS-PLW-759 |
| 3393 | SV3-CCS-PHW-ME2916 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-CCS-PLW-091 |
| 3394 | SV3-CDS-PHW-ME2504 | INSTALLATION OF CDS SUPPORTS FOR ISOMETRICS SV3-CDS-PLW-100, SV3-CDS-PLW-101, SV3-CDS-PLW-102, SV3-CDS-PLW-743, SV3-CDS-PLW-910. |
| 3395 | SV3-CVS-P0W-ME2825 | INSTALLATION OF LARGE BORE CVS PIPING (INCLUDES ISOMETRICS: SV3-CVS-PLW-021, 183) |
| 3396 | SV3-CVS-P0W-ME2826 | INSTALLATION OF LARGE BORE CVS PIPING (INCLUDES ISOMETRICS: SV3-CVS-PLW-091, 094) |
| 3397 | SV3-FPS-P0W-ME2670 | FABRICATE AND INSTALL PHASE 5 FIRE PROTECTION SYSTEM (FPS) SOUTH OF THE RAD WASTE BUILDING. (ISO'S SV3-FPS-PLW-951,95BC,95AC,95AD,95AB) |
| 3398 | SV3-FPS-PLW-ME4839 | INITIAL ENERGIZATION - INSTALLATION OF ANNEX FIRE PROTECTION SYSTEM (FPS) PIPING IAW (ISOMETRICS SV3-FPS-PLW-343, -295) |
| 3399 | SV3-HDS-P0W-ME3748 | INSTALLATION AND FABRICATION OF HEATER DRIN SYSTEM(HDS) PIPING |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3400 | SV3-ML05-MLW-ME2818 | ATTACHMENT OF COLLAR RING FOR SV3-12365-ML-P48, SV3-12365-ML-P03, AND SV3-12365-ML-P25 |
| 3401 | SV3-ML05-MLW-ME4784 | INSTALLATION OF PENETRATION 11205-ML-P03 (CA01) |
| 3402 | SV3-ML05-MLW-ME4822 | CA01 Penetration 11504-ML-P03 (ASME) |
| 3403 | SV3-ML05-MLW-ME4824 | INSTALLATION OF PENETRATION 11205-ML-P01 (CA01) |
| 3404 | SV3-ML05-MLW-ME5037 | INSTALLATION OF CA01 PENETRATIONS |
| 3405 | SV3-ML05-MLW-ME5038 | INSTALLATION OF CA01 PENETRATIONS |
| 3406 | SV3-MS01-MEW-ME4612 | INSTALLATION OF WATER-COOLED CENTRIFUGAL WATER CHILLERS SV3-VWS-MS-01A & 01B |
| 3407 | SV3-MS19-MEW-ME2639 | Install MB Condensate Polisher Spent Resin Holdup Tank (CPS-MV-02) |
| 3408 | SV3-MS30-MEW-ME2638 | INSTALL TB CHEMICAL SKIDS (CFS-MS-02D/-05C/-06) |
| 3409 | SV3-PWS-P0W-ME4944 | INITIAL ENERGIZATION - INSTALLATION OF ANNEX PORABLE WATER SYSTEM (PWS) PIPING INCLUDING ISOMETRICS: SV3-PWS-PLW-170, -193, -406, -475, -493, -495 THRU 499 |
| 3410 | SV3-PXS-P0W-ME2674 | Installation of Small Bore PXS Piping (Includes Isometric: SV3-PXS-PLW-66X) |
| 3411 | SV3-PXS-P0W-ME2732 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-01L (LINE NUMBERS PXS-PL-L022A) |
| 3412 | SV3-PXS-P0W-ME2733 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-01M (LINE NUMBERS PXS-PL-L024A) |
| 3413 | SV3-PXS-P0W-ME2734 | ASME Section III - Fabrication/Installation of Isometric # SV3-PXS-PLW-01N (Line Numbers PXS-PL-L023A) |
| 3414 | SV3-PXS-P0W-ME2736 | ASME SECTION III- FABRICATION/INSTALLATION OF ISOMECTRIC# SV3-PXS-PLW-01W (LINE NUMBERS PXS-PL-L059A) |
| 3415 | SV3-PXS-P0W-ME2738 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-01Y (LINE NUMBERS PXS-PL-L136A) |
| 3416 | SV3-PXS-P0W-ME2886 | ASME SECTION III- FARICATION/INSTALLATION OF ISOMETRIC#SV3-PXS-PLW-011 (LINE NUMBERS PXS-PL-L015A) |
| 3417 | SV3-SWS-PHW-ME5446 | FABRICATION AND INSTALLATION OF PIPE SUPPORTS FOR ISOS SV3-SWS-PLW-051, -052, -062, -063 |
| 3418 | SV3-SWS-PHW-ME5447 | FABRICATION AND INSTALLATION OF PIPE SUPPORTS FOR SWS SYSTEM |
| 3419 | SV3-SWS-THW-ME6788 | HYDRO TEST THE SERVICE WATER SYSTEM (SWS) IN PHASE 3A. |
| 3420 | SV3-VAS-MDW-ME4772 | FABRICATION AND INSTALLATION OF VAS DUCT IN ROOM 12153 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3421 | SV3-VYS-P0W-ME4478 | FABRICATE AND INSTALL ANNEX HOT WATER HEATING SYSTEM (VYS) PIPING IAW (ISOMETRICS SV3-VYS-PLW-431, -432, 433, -434, -438, -439, -444, -445) |
| 3422 | SV3-WLS-P0W-ME2908 | FABRICATE AND INSTALL UNIT 3 WLS PIPING FROM RADWASTE BUILDING THROUGH PHASE 5 |
| 3423 | SV3-WLS-PHW-ME3031 | INSTALLATION OF SMALL BORE WLS PIPE SUPPORTS ON R104 MODULE |
| 3424 | SV3-WRS-P0W-ME2991 | INSTALLATION OF SMALL BORE WRS PIPING ON R104 MODULE |
| 3425 | SV3-WRS-P0W-ME4429 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES ISOMETRICS SV3-WRS-PLW-80A, - 80W, -865 |
| 3426 | SV3-WRS-PHW-ME4385 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-WRS-PLW-594 |
| 3427 | SV3-WRS-PHW-ME4386 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-WRS-PLW-65R, 651 |
| 3428 | SV3-WRS-PLW-ME4452 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES SV3-WRS-PLW-833, 873) |
| 3429 | SV3-WRS-PLW-ME4458 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES SV3-WRS-PLW-84N, 86M) |
| 3430 | SV3-WRS-PLW-ME4469 | CA20 LEAK CHASE TESTING PROCEDURE FOR CHANNELS CONNECTING TO THE FUEL TRANSFER CANAL (FHS-MT-02) |
| 3431 | SV3-WRS-PLW-ME4470 | CA20 LEAK CHASE TESTING PROCEDURE FOR CHANNELS CONNECTING TO THE CASK LOADING PIT (FHS-MT-05) |
| 3432 | SV3-WRS-PLW-ME4471 | CA20 LEAK CHASE TESTING PROCEDURE FOR CHANNELS CONNECTING TO THE CASK WASHDOWN PIT (FHS-MT-06) |
| 3433 | SV3-WWS-P0W-ME2633 | ANNEX BUILDING - ELEVATION 115+ WWS PIPING #1 |
| 3434 | SV3-WWS-P0W-ME2662 | WWS EMBEDED PIPING INSTALLATION (INCLUDING ISOMETRIC SV3-WWS-PLW-020) |
| 3435 | SV3-WWS-P0W-ME2692 | Annex Building - Elevation 100+ WWS Piping #3 |
| 3436 | SV3-WWS-P0W-ME2693 | ANNEX BUILDING- ELEVATION 100+ WWS PIPING #4 |
| 3437 | SV3-WWS-P0W-ME4627 | INSTALLATION OF TURBINE BUILDING WWS PIPING FOR SLAB 1 ON 120'-6" ELEVATION |
| 3438 | SV3-WWS-P0W-ME4628 | INSTALLATION OF TURBINE BUILDING WWS PIPING FOR SLABS 4, 5, 6 ON 120'-6" |
| 3439 | SV3-WWS-PHW-ME3073 | INSTALLATION OF ANNEX WWS PIPING SUPPORTS (FOR WP SV3-WWS-P0W-ME2692) |
| 3440 | SV3-WWS-PHW-ME3075 | INSTALLATION OF ANNEX WWS PIPING SUPPORTS (FOR WP SV3-WWS-P0WME2694) |
| 3441 | SV3-WWS-PHW-ME3653 | INSTALLATION OF TURBINE BUILDING WWS PIPING SUPPORTS FOR ISOMETRICS SV3-WWS-PLW-06B, 06BF, 06D, 06E, 06F, 06G, 06L, 06J, 06K, 06P |
| 3442 | SV4-WWS-CCW-CV6768 | UNIT 4 WWS DUCTBANK |
| 3443 | SV4-WWS-PLW-ME1346 | WWS LINE TO WWRB |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3444 | SV4-CA01-S4W-861784 | CA01-SA07 ELEV ABOVE 119' OLPS AND WELDED ATTACHMENTS |
| 3445 | SV0-SES-ERW-862927 | INSTALL CONDUIT IN SES DUCT BANK/TRENCH FOR SECURITY LOCATED BETWEEN SITE GRID M101-L1502 PHASE 10 |
| 3446 | SV3-4031-SHW-861531 | FABRICATE AND INSTALL CABLE TRAY SUPPORTS ANNEX BLDG. AREA 1, ELEV. 100¿, BETWEEN COLUMN LINES 11.09/11.15 & G/I. |
| 3447 | SV3-4000-SHW-862383 | FABRICATION AND INSTALLATION OF TYPICAL FIELD ROUTED CONDUIT SUPPORTS, DETAILS C-71, ANNEX BUILDING, ALL AREAS/ELEVATIONS. BOOK 1 |
| 3448 | SV3-FPS-P0W-854240 | INSTALL LB CONTAINMENT UPPER RING HEADER PIPING PER ISO'S SV3-FPS-PLW-552, 55Q, 553, 55R, 55K. |
| 3449 | SV3-WWS-P0W-ME2484 | WWS EMBEDED PIPING INSTALLATION (INCLUDING ISOMETRICS SV3-WWS-PLW-32C, -32E, -32F, -32G) |
| 3450 | SV3-WRS-P0W-ME4433 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES ISOMETRICS SV3-WRS-PLW-80F) |
| 3451 | SV4-0000-CCW-CV7168 | Concrete and Rebar for the Diesel and Electric-Driven Pump Enclosure Foundation |
| 3452 | SV4-1000-CCW-CV1470 | Unit 4 Nuclear Island Basemat Concrete Placement Up To 66'-6" |
| 3453 | SV3-WWS-PHW-ME2960 | INSTALLATION OF LARGE BORE WWS PIPING SUPPORTS (INCLUDES ISOMETRICS SV3-WWS-PLW-01D) |
| 3454 | SV4-1000-CRW-CV1736 | UNIT 4, WEST SHIELD WALL REBAR BELOW 100' ELEVATION |
| 3455 | SV3-WWS-PHW-ME3043 | SV3-WWS-PHW-ME3043 |
| 3456 | SV4-1000-CRW-CV1744 | UNIT 4, SHIELD BUILDING, EAST PERIMETER WALL REBAR FROM 66'-6" TO 82'-6" |
| 3457 | SV3-WWS-PHW-ME3045 | INSTALLATION OF WWS PIPE SUPPORTS FOR SLAB 3 AT 120' 6" ELEVATION PORTION 3 |
| 3458 | SV4-1010-CRW-CV1748 | INSTALLATION OF #9 AND #11 WALL DOWELS AFTER BASE MAT CONCRETE PLACEMENT |
| 3459 | SV4-1020-CRW-CV1745 | UNIT 4, SHIELD BUILDING, EAST PERIMETER WALL REBAR FROM 82'-6" TO 100'-0" |
| 3460 | SV4-1100-ERW-EL2285 | CONTAINMENT BUILDING EX CORE INSTRUMENTATION EMBEDDED CONDUIT EL 71FT-6IN TO 10FT-2IN |
| 3461 | SV3-WWS-PHW-ME3072 | INSTALLATION OF ANNEX WWS PIPING SUPPORTS (FOR WP SV3-WWS-P0W-ME2691) |
| 3462 | SV4-1100-Z0W-CV3929 | UNIT 4 CONTAINMENT REINFORCED CONCRETE REQUIREMENTS |
| 3463 | SV4-1110-CCW-CV1919 | Containment Concrete - EL. 71'-6" |
| 3464 | SV4-1110-CCW-CV5151 | UNIT 4 INSIDE CVBH CORE DRILLING IN CONCRETE PLACEMENT AT ELEVATION 76'-6" |
| 3465 | SV3-WWS-PLW-ME3028 | INSTALLTION OF WWS PIPING FOR SLAB 3 AT 120'6" EKEVATION |
| 3466 | SV4-1110-CEW-CV1878 | CONTAINMENT CONCRETE EMBEDMENTS - EL. 71'-6" |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3467 | SV4-1110-CEW-CV6676 | INSTALLATION OF UNIT 4 STEAM GENERATOR COLUMN PEDESTAL EMBEDMENTS |
| 3468 | SV4-1110-CRW-CV1837 | Containment Vessel Bottom Head Layers A, B, & C |
| 3469 | SV4-1120-CEW-CV4911 | U4 NUCLEAR ISLAND CONTAINMNET EMBEDS AND ANCHOR BOLTS ELEVATION 71'-6" TO 84'-6" |
| 3470 | SV4-1120-CRW-CV3063 | CONTAINMENT CONCRETE REINFORCEMENT EL 71 FT-6IN TO EL 76FT-6IN |
| 3471 | SV4-2040-SSW-CV3969 | UNIT 4 TURBINE BUILDING SEQUENCE 7 HANDRAIL AND STAIRS |
| 3472 | SV4-ECS-ERW-EL6124 | SV4-INSTALL ECS DUCT BANKS FROM MANHOLES NXM010, NXM011 TO FIRE PUMPS/FIRE WATER TANKS - PHASE 8A |
| 3473 | SV4-1120-EGW-EL2342 | INSTAL GROUNDING IN UNIT 4 CONTAINMENT BUILDING AT ELEVATION 82' 6" TO 100' 0" |
| 3474 | SV4-ECS-ERW-EL6125 | SV4-INSTALL ECS DUCT BANKS FROM NORTH SIDE OF UNIT 4 TURBINE BLDG TO CHEMICAL FEED STORAGE BLDG - PHASE 8A |
| 3475 | SV4-1200-AXW-CT7673 | COATINGS - U4 AUX. BUILDING AREAS 3 & 4 CONCRETE COATINGS |
| 3476 | SV4-1200-CRW-CV1741 | UNIT 4 NUCLEAR ISLAND AUXILIARY BUILDING-INSTALLATION OF REINFORCING STEEL ON INTERIOR WALLS UP TO 82'-6" (WALL PLACEMENTS 9 THRU 38) |
| 3477 | SV4-WRS-P0W-ME5964 | FABRICATION AND INSTALLATION OF SMALL BORE WRS PIPING (ISOMETRIC SV4-WRS-PLW-57Q) |
| 3478 | SV4-WWS-PLW-ME1766 | Installation of Large Bore WWS Piping (Includes Isometrics SV4-WWS-PLW-01B, -01D, -014) |
| 3479 | SV4-1210-CCW-CV1815 | Unit 4 Nuclear Island Auxiliary Building Concrete Placement For Interior Walls From Elevation 66'-6" (Wall Placements #9 THRU 38) -REV. 0- |
| 3480 | SV4-1210-CEW-CV1738 | U4 Auxiliary Building Embed Plates-EL 66'6"- Interior Walls |
| 3481 | SV4-1210-CEW-CV1739 | U4 AUXILIARY BUILDING EMBEDMENTS-CYLINDRICAL WALL-EL. 66'-6" |
| 3482 | SV4-1210-EGW-EL1798 | INSTALL GROUNDING FOR WALL POURS 1, 3, 4 AND 5 |
| 3483 | SV4-1210-ERW-EL1810 | UNIT 4 AUXILIARY BUILDING, INSTALL ELECTRICAL PENETRATIONS & GROUNDING FOR WALLS 34,35,36,37 & 38. SECTIONS 4,5 & 6. ELEVATION 66'-6" TO 82'-6" |
| 3484 | SV4-1210-MLW-CV2466 | U4 CIVIL BLOCKOUTS FOR MECHANICAL & ELECTRICAL PENETRATIONS-AUX. BUILDING WALLS EL. 66'-6" TO EL. 82'-6" |
| 3485 | SV4-1220-CCW-CV2318 | UNIT 4 CONCRETE PLACEMENT OUTSIDE CVBH UP TO ELEVATION 82'-6" |
| 3486 | SV4-1220-CCW-CV2540 | Unit 4 Nuclear Island Auxiliary Building Concrete Placement for Exterior Walls from Elev. 82'-6" to 100'-0" (Wall Placements 39 thru 48) |
| 3487 | SV4-1220-CCW-CV2541 | UNIT 4 NUCLEAR ISLAND AUXILIARY BUILDING AREAS 1 AND 2 CONCRETE PLACEMENT FOR INTERIOR WALLS FROM ELEVATION 82'-6" TO 100'-0" |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3488 | SV4-1220-CEW-CV1612 | Unit 4 Nuclear Island AUX. BLDG AREAS 1 THRU 6 - EL 82' -6 WALLS- MECHANICAL/ELECTRICAL PENETRATION BLOCKOUTS & BLOCKOUT EMBEBMENTS |
| 3489 | SV4-1220-CEW-CV2434 | U4 AUXILIARY BUILDING EMBED PLATES & FORM WORK FOR AREA 1-EL 82'-6" WALLS |
| 3490 | SV4-1220-CEW-CV2436 | U4 AUXILIARY BUILDING EMBED PLATES & TEMPORARY FORMWORK-AREA 3 & 4- EL. 82'-6" WALLS |
| 3491 | SV4-1220-CRW-CV2538 | UNIT 4 NUCLEAR ISLAND AUXILIARY BUILDING - INSTALLATION OF REINFORCING STEEL ON EXTERIOR WALLS FROM ELEV. 82'6" TO 100'0" (WALL PLACEMENTS 39 THRU 48) |
| 3492 | SV4-1220-CRW-CV2539 | UNIT 4 NUCLEAR ISLAND AUXILIARY BUILDING AREAS 1 AND 2 INSTALLATION OF REINFORCING STEEL ON INTERIOR WALLS FROM ELEV. 82'6" TO 100;0" (WALL PLACEMENTS 49 THRU 71) |
| 3493 | SV4-1220-EGW-EL2723 | INSTALL GROUNDING GRID AND FLOOR PLATES FOR 82'-6" SLAB AREAS 1,2 & 3 |
| 3494 | SV4-1220-EGW-EL2724 | INSTALL GROUNDING GRID AND FLOOR PLATES FOR 82'-6" SLAB AREAS 4, 5 & 6 |
| 3495 | SV4-1220-EGW-EL5784 | Install Grounding For Shield Wall Elevation 82'-6" to 100'-0"" |
| 3496 | SV4-1230-EGW-EL3664 | ISNTALL GROUNGING GRID AND FLOOR PLATES FOR 100'-0" SLAB AREAS 1,2 & 3 |
| 3497 | SV4-1230-EGW-EL3665 | INSTALL GROUNDING GRID AND FLOOR PLATES FOR 100'-0" SLAB AREAS 4,5, & 6 |
| 3498 | SV3-2056-SHW-800003 | Elect Cable Tray Welded Support Fab & Install in Unit 3 Turbine Building, Elevation 141' 3", Area 6 |
| 3499 | SV4-2000-T2W-CV1584 | HSB Assembly & Installer Qualification For Turbine Building |
| 3500 | SV4-2020-CCW-CV0388 | Unit 4, Turbine Building Grout below Elev. 100' |
| 3501 | SV4-2020-EGW-EL3437 | ELECTRICAL GROUNDING TERMINATIONS FOR THE TURBINE BUILDING AT ELEVATION 82'-9" |
| 3502 | SV4-2020-MEW-ME1128 | Unit 4 Condenser A Hotwell Assembly |
| 3503 | SV4-2020-MEW-ME1129 | Unit 4 Condenser B Hotwell Assembly |
| 3504 | SV4-2020-MEW-ME1130 | Unit 4 Condenser C Hotwell Assembly |
| 3505 | SV4-2020-MEW-ME1131 | Unit 4 Condenser A Lower Tube Bundle Assembly |
| 3506 | SV4-2020-MEW-ME1132 | Unit 4 Condenser B Lower Tube Bundle Assembly |
| 3507 | SV4-2020-MEW-ME1133 | Unit 4 Condenser C Lower Tube Bundle Assembly |
| 3508 | SV4-2020-MEW-ME1134 | Unit 4 Condenser A Upper Tube Bundle Assembly |
| 3509 | SV4-2020-MEW-ME1135 | Unit 4 Condenser B Upper Tube Bundle Assembly |
| 3510 | SV4-2020-MEW-ME1136 | Unit 4 Condenser C Upper Tube Bundle Assembly |
| 3511 | SV4-2020-MEW-ME1137 | Unit 4 Condenser A Upper Shell Exterior Shell Assembly |
| 3512 | SV4-2020-MEW-ME1138 | Unit 4 Condenser A Upper Shell Heater Truss Assembly |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3513 | SV4-2020-MEW-ME1139 | Unit 4 Condenser A Upper Shell Upper Truss Assembly |
| 3514 | SV4-2020-MEW-ME1141 | Unit 4 Condenser B Upper Shell Exterior Shell Assembly |
| 3515 | SV4-2020-MEW-ME1145 | Unit 4 Condenser C Upper Shell Exterior Shell Assembly |
| 3516 | SV4-2020-MEW-ME1146 | Unit 4 Condenser C Upper Shell Heater Truss Assembly |
| 3517 | SV4-2020-MEW-ME1147 | Unit 4 Condenser C Upper Shell Upper Truss Assembly |
| 3518 | SV4-2020-MEW-ME1400 | Unit 4 Condenser A Spring Support Foundation Installation |
| 3519 | SV4-2020-MEW-ME1401 | UNIT 4 CONDENSER B SPRING SUPPORT FOUNDATION INSTALLATION |
| 3520 | SV4-2020-MEW-ME1402 | Unit 4 Condenser C Spring Support Foundation Installation |
| 3521 | SV4-2020-MEW-ME1491 | UNIT 4 CONDENSER A INSTALLATION (LOWER & UPPER SHELL) |
| 3522 | SV4-2020-MEW-ME1492 | UNIT 4 CONDENSER B INSTALLATION (LOWER & UPPER SHELL) |
| 3523 | SV4-2020-MEW-ME1493 | Unit 4 Condenser C Installation (Lower & Upper Shell) |
| 3524 | SV4-2020-MEW-ME1600 | UNIT 4 CONDENSER A FLASHBOX INSTALLATION |
| 3525 | SV3-WWS-P0W-ME4630 | INSTALLATION OF WWS PIPING |
| 3526 | SV4-2030-CCW-CV0385 | UNIT 4 TURBINE BUILDING CONCRETE CURBS AND PADS AT 100' ELEVATION |
| 3527 | SV4-2030-CCW-CV0389 | UNIT 4 TURBINE BUILDING GROUT AT THE 100' ELEVATION |
| 3528 | SV4-2030-CCW-CV1458 | UNIT 4, TURBINE BUILDING STAIR LANDINGS |
| 3529 | SV4-2030-CEW-CV1389 | UNIT 4 TURBINE BLDG FABRICATION OF CONSTRUCTION AIDS FOR 100'-0" |
| 3530 | SV4-2030-EGW-EL1079 | Electrical Grounding Installation for the Turbine Building at Elevation 100'-0" |
| 3531 | SV4-2030-EGW-EL4819 | ELECTRICAL GROUNDING TERMINATIONS FOR THE TURBINE BUILDING AT ELEVATION 100' |
| 3532 | SV4-2030-SSW-CV1825 | TURBINE BUILDING STRUCTURAL STEEL FRAMING @ 100FT. ELEVATION EXCLUDING FIRST BAY (SEQUENCE SIX) |
| 3533 | SV4-2040-CCW-CV0387 | UNIT 4, TURBINE BUILDING CONCRETE PLACEMENT AND POST-PLACEMENT ACTIVITIES, 120' ELEVATION |
| 3534 | SV4-2040-CEW-CV5843 | UNIT 4 TURBINE ELEVATION 120'-6" FORMWORK, EMBEDS, ANCHOR BOLTS |
| 3535 | SV4-2040-SSW-CV3970 | UNIT 4 TURBINE BUILDING SEQUENCE 7 GRATING & DECKING |
| 3536 | SV4-2040-SUW-CV1826 | TURBINE BUILDING STRUCTURAL STEEL ERECTION SEQUENCE 7 |
| 3537 | SV4-2060-C0W-850005 | 170' ELEV. FLOOR SLAB, POUR # 5 |
| 3538 | SV4-2101-CEW-CV5807 | UNIT 4, TURBINE BUILDING FIRST BAY WALLS, DOOR FRAMES |
| 3539 | SV4-2101-CFW-CV5805 | UNIT 4, TURBINE BUILDING FIRST BAY WALLS, FORMWORK |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3540 | SV4-2101-CRW-CV5802 | UNIT 4, TURBINE BUILDING, FIRST BAY WALLS UP TO 122' ELEV. REBAR |
| 3541 | SV4-2101-CRW-CV5803 | Unit 4, Turbine Building, 1st Bay Walls, Wall to Wall Mechanical Couplers up to 122’ |
| 3542 | SV4-2131-CCW-CV0391 | UNIT 4, TURBINE BUILDING, FIRST BAY CONCRETE UP TO 100' ELEVATION AND EQUIPMENT PADS |
| 3543 | SV4-4000-CEW-CV5067 | UNIT 4, ANNEX BUILDING CONSTRUCTION AIDS |
| 3544 | SV4-4000-CRW-CV5094 | UNIT 4 ANNEX BUILDING REBAR BENDING AND FABRICATION |
| 3545 | SV4-4000-Z0W-CV5066 | UNIT 4, ANNEX BUILDING, REINFORCED CONCRETE REQUIREMENTS |
| 3546 | SV4-ASS-P0W-ME5421 | INSTALLATION AND FABRICATION OF AUXILIARY STEAM SYSTEM (ASS) PIPING |
| 3547 | SV4-ASS-P0W-ME5424 | INSTALLATION AND FABRICATION OF AUXILIARY STEAM SUPPLY SYSTEM (ASS) PIPING PORTION 4 |
| 3548 | SV4-ASS-P0W-ME5425 | INSTALLATION AND FABRICATION OF AUXILIARY STEAM SUPPLY SYSTEM (ASS) PIPING PORTION 5 |
| 3549 | SV4-ASS-P0W-ME5426 | INSTALLATION AND FABRICATION OF AUXILIARRY STEAM SUPPLY SYSTEM PIPING PORTION 6 |
| 3550 | SV4-ASS-PHW-ME5427 | Installation and Fabrication of Auxiliary Steam System(ASS) Piping Supports |
| 3551 | SV3-CVS-P0W-ME2648 | INSTALLATION OF SMALL BORE CVS PIPING (INCLUDES ISOMETRICS: SV3-CVS-PLW-04C) |
| 3552 | SV4-ASS-PHW-ME5428 | INSTALLATION AND FABRICATION OF AUXILIARY STEAM SYSTEM(ASS) PIPING SUPPORTS PORTION 1 |
| 3553 | SV4-ASS-PHW-ME5429 | INSTALLATION AND FABRICATION OF PIPE SUPPORTS PORTION 2 |
| 3554 | SV4-ASS-PHW-ME5430 | INSTALLATION AND FABRICATION OF AUXILIARY STEAM SUPPLY SYSTEM (ASS) PIPING SUPPORT PORTION 3 |
| 3555 | SV4-ASS-PHW-ME5431 | INSTALLATION AND FABRICATION OF AUXILIARY STEAM SUPPLY SYSTEM (ASS) PIPING SUPPORT PORTION 4 |
| 3556 | SV4-ASS-PHW-ME5432 | INSTALLATION AND FABRICATION OF AUXILIARY STEAM SUPPLY SYSTEM(ASS) PIPING SUPPORT PORTION 5 |
| 3557 | SV4-ASS-PHW-ME5433 | FABRICATION AND INSTALLATION OF ASS PIPE SUPPORTS (PORTION 6) |
| 3558 | SV4-C0S7-CCW-CV0544 | Electrical Duct Bank for Unit 4 CWS, Cooling Water System |
| 3559 | SV4-CA04-S4W-CV2447 | Lifting Lugs and Temporary Attachments for Unit 4 CA04 |
| 3560 | SV4-CA20-S4W-CV6894 | CA20-51 TEMPORAR ATTACHMENTS - FLOOR |
| 3561 | SV4-CB65-S4W-CV2665 | FABRICATION OF OVERLAY PLATES (OLP) FOR CB65 |
| 3562 | SV4-CDS-CCW-CV7060 | U4 Condensate Tank Storage Foundation |
| 3563 | SV4-CES-P0W-ME7576 | Installation of CES piping (Portion 1) |
| 3564 | SV4-CPS-P0W-ME1668 | UNIT 4 TURBINE BUILDING EL 100'-0": FABRICATION & INSTALLATION OF EMBEDDED CPS PIPING |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3565 | SV4-CR10-CRW-CV1154 | The Erection of Structural Steel for the CR10 module on Pad 139 |
| 3566 | SV4-CR10-CRW-CV1416 | INSTALLATION OF CR 10 UNIT 4 NUCLEAR ISLAND REINFORCING STEEL LAYERS 4-10 |
| 3567 | SV4-CWS-ERW-EL0352 | Electrical Installation of (CWS) Cooling Water System Manholes & Duct Banks |
| 3568 | SV4-CWS-P0W-ME1713 | INSTALLATION OF LARGE BORE CWS PIPING AT GRIDLINE R |
| 3569 | SV4-CWS-P0W-ME2758 | Installation of CWS Piping from Backwash Strainers to Yard. |
| 3570 | SV4-CWS-P0W-ME5457 | TO INSTALL AND FABRICATE CIRCULATING WATER SYSTEM (CWS) PIPING |
| 3571 | SV4-CWS-P0W-ME7467 | INSTALLATION OF CROSSOVER PIPING FROM CONDENSER A TO CONDENSER B |
| 3572 | SV4-CWS-P0W-ME7468 | INSTALLATION OF CROSSOVER PIPING FROM CONDENSER B TO CONDENSER C |
| 3573 | SV4-CWS-PHW-ME1716 | INSTALLATION OF LARGE BORE CWS PIPING SUPPORTS AT GRIDLINE R |
| 3574 | SV4-CWS-PHW-ME5470 | INSTALLATION AND FABRICATION OF AUXILIARY STEAM SUPPLY SYSTEM (ASS) PIPING SUPPORT |
| 3575 | SV4-CWS-PHW-ME7469 | INSTALLATION OF PIPE SUPPORTS FOR 120" CROSSOVER PIPING FROM CONDENSER A TO CONDENSER B |
| 3576 | SV4-CWS-PHW-ME7470 | INSTALLATION OF PIPE SUPPORTS FOR 120" CROSSOVER PIPING FROM CONDENSER 'B' TO CONDENSER 'C' |
| 3577 | SV4-DTS-P0W-ME1714 | INSTALLATION OF DTS PIPING FROM YARD TO CARTRIDGE FILTER SKID SV4-DTS-MS-01 |
| 3578 | SV4-DTS-PHW-ME1717 | INSTALLATION OF DTS PIPING SUPPORTS FROM YARD TO CARTRIDGE FILTER SKID SV4-DTS-MS-01 |
| 3579 | SV4-FPS-MPW-ME7582 | Install Unit 4 Diesel Fire Pump Package SV4-FPS-MS-01B |
| 3580 | SV4-FPS-P0W-ME1943 | INSTALLATION OF LARGE BORE FPS PIPING (INCLUDES ISOMETRICS: SV4-FPS-PLW-820, 825, 830) |
| 3581 | SV4-HDS-P0W-ME5463 | INSTALLATION AND FABRICATION OF HEATER DRAIN SYSTEM(HDS) PIPING |
| 3582 | SV4-ME01-P0W-ME2589 | UNIT 4 CONDENSERS A, B & C - TURBINE BYPASS PIPING |
| 3583 | SV4-ME01-PLW-ME0992 | Unit 4 Condenser A: Installation of Hotwell Piping |
| 3584 | SV4-ME01-PLW-ME1000 | Unit 4 Condenser B: Installation of Hotwell Piping |
| 3585 | SV4-ME01-PLW-ME1002 | UNIT 4 CONDENSER C: INSTALLATION OF HOTWELL PIPING |
| 3586 | SV4-ME01-PLW-ME1004 | UNIT 4 CONDENSER A: INSTALLATION OF UPPER SHELL NOZZLE CONNECTIONS |
| 3587 | SV4-ME2W-MEW-ME3012 | INSTALLATION OF HDS DRAIN COOLER CDS-ME-7A |
| 3588 | SV4-ME2W-MEW-ME3019 | INSTALLATION OF HDS DRAIN COOLER CDS-ME-7B |
| 3589 | SV4-ME2W-MEW-ME3020 | INSTALLATION OF HDS DRAIN COOLER CDS-ME-7C |
| 3590 | SV4-ME3C-MEW-ME2970 | INSTALLATION OF TCS HEAT EXCHANGERS SV4-TCS-ME-01A/B/C |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3591 | SV4-ML05-MLW-ME4811 | INSTALLATION OF EMBEDDED PIPING PENETRATIONS 82'-6" FLOORS ONLY |
| 3592 | SV4-ML05-MLW-ME5280 | INSTALLATION OF 82'6" WALL PENETRATIONS |
| 3593 | SV4-ML05-MLW-ME5281 | WELDING OF NELSON STUDS 82'6" WALL PENETRATIONS |
| 3594 | SV4-ML05-MLW-ME6290 | INSTALLATION OF ANNULUS WALL PENETRATIONS 82'6 TO 100'0 |
| 3595 | SV4-MP03-MPW-ME2343 | UNIT 4 TURBINE BUILDING EL82'-9": INSTALLATION OF CONDENSATE SYSTEM (CDS) PUMPS SV4-CDS-MP-01A/B/C |
| 3596 | SV4-MP1H-MPW-ME7109 | INSTALLATION OF TURBINE BUILDING CLOSED COOLING WATER PUMPS (TCS-MP-01A/B) |
| 3597 | SV4-MP2D-MPW-ME6764 | INSTALLATION OF HDS SHELL DRAIN TANK PUMP SV4-HDS-MP-01A |
| 3598 | SV4-MP2D-MPW-ME6765 | INSTALLATION OF HDS SHELL DRAIN TANK PUMP SV4-HDS-MP-01B |
| 3599 | SV4-MS13-MSW-ME5923 | INSTALLATION OF THE BALL COLLECTOR SKID (MS-01A/B) |
| 3600 | SV4-MS13-MSW-ME5924 | Installation of Ball Recirculation Pump (MS-02A/B |
| 3601 | SV4-MS21-MSW-ME5919 | INSTALLATION OF THE CONDENSER HOTWELL SAMPLE PUMPS (SSS-MS-01 A/B/C) |
| 3602 | SV4-1110-CCW-CV3190 | Containment Interior Concrete Placement - Elev. 71'-6" to 76'-6"" |
| 3603 | SV4-MS45-MSW-ME3024 | INSTALLATION OF MAIN & BOOSTER FEEDWATER PUMPS SV4-FWS-MP-01A/-02A |
| 3604 | SV4-MS45-MSW-ME3025 | INSTALLATION OF MAIN & BOOSTER FEEDWATER PUMPS SV4-FWS-MP-01B/-02B |
| 3605 | SV4-MS45-MSW-ME3026 | INSTALLATION OF MAIN & BOOSTER FEEDWATER PUMPS SV4-FWS-MP-01C/02C |
| 3606 | SV4-MS60-MSW-ME5879 | INSTALLATION OF THE AUXILIARY BIOLER (ASS-MB-01) |
| 3607 | SV4-MS60-MSW-ME5920 | INSTALLATION OF THE AUXILIARY BOILER BLOWDOWN FLASH TANK (ASS-MT-01) |
| 3608 | SV4-MS60-MSW-ME5921 | INSTALLATION OF THE AUXILIARY BOILER FEED PUMPS (ASS-MP-04A/) |
| 3609 | SV4-MS60-MSW-ME7100 | INSTALLATION OF THE AUX BOILER MAKEUP PUMPS (ASS-MP-01A/B) |
| 3610 | SV4-1220-CEW-CV2435 | U4 AUXILIARY BUILDING EMBED PLATES & FORMWORK-AREA 2-EL.82'-6" |
| 3611 | SV4-PGS-P0W-ME1997 | INSTALLATION OF PGS PIPING (INCLUDES SV4-PGS-PLW-105, 128) |
| 3612 | SV4-PV74-PVW-ME3071 | INSTALLATION OF 120" CWS BUTTERFLY VALVES CWS-PL-V002A, -V002B, -V003A, -V003B |
| 3613 | SV4-1220-CEW-CV2437 | U4 AUXILIARY BUILDING EMBED PLATES & FORMWORK- AREA 5&6- EL, 82'-6" WALLS |
| 3614 | SV4-PWS-P0W-ME2003 | INSTALLATION OF SMALL BORE PWS PIPING (INCLUDES ISOMETRIC SV3-PWS-PLW-91A, 911, 950, 951, 952, 953) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3615 | SV4-2000-CRW-CV2974 | UNIT 4 TURBINE BLDG. REBAR BENDING AND FABRICATION |
| 3616 | SV4-PWS-P0W-ME2005 | Installation of Potable Water Piping (Isometric PWS-PLW-923) |
| 3617 | SV4-2000-SUW-CV1821 | ASSEMBLY AND ERECTION OF CH82 MODULE IN AREA 111 |
| 3618 | SV4-PWS-PHW-ME5965 | FABRICATION/INSTALLATION OF SMALL BORE PWS PIPING SUPPORTS FOR ISOMETRIC DRAWING SV4-PWS-PLW-91A, 911, 950, 951, 952, 953 |
| 3619 | SV4-PY05-PYW-ME2756 | INSTALLATION OF SWS BACKWASH STRAINERS (SWS-PY-S06A, SWS-PY-S06B) |
| 3620 | SV4-2000-SUW-CV1822 | Assembly and Erection Of CH81A, B, & C |
| 3621 | SV4-PY05-PYW-ME2757 | INSTALLATION OF CWS BACKWASH STRAINERS (CWS-PY-S01A, CWS-PY-S01B, CWS-PY-S01C) |
| 3622 | SV4-CA01-MHW-862926 | CA01 LIFTING LUGS FOR THE PRESSURIZER COMPARTMENT |
| 3623 | SV4-CWS-PLW-ME1115 | UNIT 4 CWS FROM PCCP TO TURBINE BUILDING |
| 3624 | SV4-RWS-P0W-ME7380 | FABRICATE AND INSTALL THE RWS SUPPLY TO THE UNIT 4 COOLING TOWER BASINS A & B AND TO THE DTS PRETREATMENT SKID |
| 3625 | SV4-SS01-Z0W-CV4378 | STRUCTURAL STEEL SAFETY CLASS E REQUIREMENTS |
| 3626 | SV4-SWS-CCW-CV2646 | UNIT 4, SWS TRENCH TUNNEL |
| 3627 | SV4-WLS-PHW-ME3286 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWINGS WLS-PLW-364, -870 |
| 3628 | SV4-SWS-CRW-CV5484 | UNIT 4, SWS TRENCH TUNNEL, MECHANCAL COUPLER INSTALLATION |
| 3629 | SV4-SWS-P0W-ME1715 | UNIT 4 TURBINE BUILDING AREA 2022: INSTALLATION OF SWS PIPING FOR ISOMETRICS SV4-SWS-PLW-090, -091, -092, -093, -094 & -095. |
| 3630 | SV4-SWS-P0W-ME2124 | FABRICATION AND INSTALLATION OF SWS PIPING FROM YARD TO STRAINER SV4-SWS-PY-S06A |
| 3631 | SV4-SWS-P0W-ME2125 | FABRICATION AND INSTALLATION OF SWS PIPING FROM YARD TO STRAINER SV4-SWS-PY-S06B |
| 3632 | SV4-SWS-P0W-ME3509 | INSTALLATION OF SWS PIPING FROM BACKWASH STRAINER SWS-PY-S06A TO SWS PUMP SWS-MP-01A |
| 3633 | SV4-SWS-P0W-ME3510 | INSTALLATION OF SWS PIPING FROM BACKWASH STRAINER SWS-PY-S06B TO SWS PUMP SWS-MP-01B |
| 3634 | SV4-SWS-P0W-ME7379 | SERVICE WATER SYSTEM (SWS) PIPING INSTALLATION IN PHASE 8A |
| 3635 | SV4-SWS-PHW-ME1718 | FABRICATION AND INSTALLATION OF PIPE SUPPORTS FOR ISOMETRICS SV4-SWS-PLW-090, -091, -092 |
| 3636 | SV4-SWS-PHW-ME2355 | Installation of SWS Supports For Isometrics SV4-SWS-PLW-07A, SV4-SWS-PLW-07B, SV4-SWS-PLW-070, SV4-SWS-PLW-071, SV4-SWS-PLW-072, SV4-SWS-PLW-078. |
| 3637 | SV4-SWS-PHW-ME2357 | iNSTALLATION OF SWS SUPPORTS FOR INOMETRICS SV4-SWS-PLW-07C, SV4-SWS-PLW-07D, SV4-SWS-PLW-074, SV4-SS-PLW-075, SV4-SWS-PLW-076, SV4-SWS-PLW-077 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3638 | SV4-SWS-PHW-ME2359 | INSTALLATION OF SWS SUPPORTS FOR ISOMETRICS SV4-SWS-PLW-07E, SV4-SWS-PLW-073, SV4-SWS-PLW-079. |
| 3639 | SV4-SWS-PHW-ME2361 | INSTALLATION OF SWS SUPPORTS FOR ISOMETRICS SV4-SWS-PLW-010, SV4-SWS-PLW-020 |
| 3640 | SV4-SWS-PHW-ME2365 | INSTALLATION OF SWS SUPPORTS FOR ISOMETRICS SV4-SWS-PLW-051, SV4-SWS-PLW-052, SV4-SWS-PLW-053, |
| 3641 | SV4-SWS-PHW-ME3303 | FABRICATION AND INSTALLATION OF PIPE SUPPORTS FOR SWS PIPING FROM CCS-ME-01A TO YARD |
| 3642 | SV4-SWS-PHW-ME3304 | FABRICATION AND INSTALLATION OF PIPE SUPPORTS FOR SWS PIPING FROM CCS-ME-01B TO YARD |
| 3643 | SV4-SWS-PHW-ME3516 | INSTALLATION OF SWS PIPING SUPPORTS FROM BACKWASH STRAINER SWS-PY-S06A TO SWS PUMP SWS-MP01A |
| 3644 | SV4-SWS-PHW-ME3517 | INSTALLATION AND FABRICATION OF SERVICE WATER SYSTEM (SWS) PIPING SUPPORTS |
| 3645 | SV4-SWS-PLW-ME2354 | INSTALLATION OF SWS PIPING FOR ISOMETRICS SV4-SWS-PLW-07A, SV4-SWS-PLW-07B, SV4-SWS-PLW-070, SV4-SWS-PLW-071, SV4-SWS-PLW-072, SV4-SWS-PLW-078. |
| 3646 | SV4-SWS-PLW-ME2356 | INSTALLATION OF SWS PIPING FOR ISOMETRICS SV4-SWS-PLW-07C, SV4-SWS-PLW-07D, SV4-SWS-PLW-074, SV4-SWS-PLW-075, SV4-SWS-PLW-076, SV4-SWS-PLW-077 |
| 3647 | SV4-SWS-PLW-ME2358 | Installation of SWS Piping for Isometrics SV4-SWS-PLW-07E,SV4-SWS-PLW-073,SV4-SWS-PLW-079 |
| 3648 | SV4-SWS-PLW-ME2360 | INSTALLATION OF SWS PIPING FOR ISOMETRICS SV4-SWS-PLW-010 AND SV4-SWS-PLW-020 |
| 3649 | SV4-SWS-THW-ME7382 | Hydro Test the Service Water System (SWS) in Phase 8A |
| 3650 | SV4-TCS-P0W-ME5464 | INSTALLATION AND FABRICATION OF TURBINE BUILDING CLOSED COOLING WATER SYSTEM (TCS) PIPING |
| 3651 | SV4-TCS-P0W-ME5465 | INSTALLATION AND FABRICATION OF TURBINE BUILDING CLOSED COOLING WTER SYSTEM (TCS) PIPING |
| 3652 | SV4-WLS-CCW-CV2849 | Unit 4 Nuclear Island- Grout Placement under the Liquid Radwaste System (WLS) Tanks |
| 3653 | SV4-WLS-MTW-ME1802 | WASTE HOLDUP TANK A INSTALLATION |
| 3654 | SV4-WLS-MTW-ME1803 | WASTE HOLDUP TANK B INSTALLATION |
| 3655 | SV4-WLS-MTW-ME1804 | WLS MONITOR TANK C INSTALLATION |
| 3656 | SV4-PXS-PHW-851018 | INSTALL SV4 RING 2 SUPPORTS FROM PIPE ISOMETRIC SV4-PXS-PLW-935 |
| 3657 | SV4-SFS-P0W-850860 | INSTALL ISOMETRIC SV4-SFS-PLW-860 |
| 3658 | SV4-RNS-P0W-861627 | ASME III FABRICATION/INSTALLATION OF CA20 LARGE BORE PIPING FOR ISOMETRIC SV4-RNS-PLW-09B |
| 3659 | SV4-PXS-PHW-851024 | INSTALL SV4 RING 2 SUPPORTS FROM PIPE ISOMETRIC SV4-PXS-PLW-946 |
| 3660 | SV4-1110-ADW-800000 | RCDT Compartment, Reactor Cavity Shield Door Installation |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3661 | SV3-2055-SHW-862713 | INSTALLATION OF WELDED SUPPORTS IN THE UNIT 3 TURBINE BUILDING, ELEVATION 141'-3", AREA 5 |
| 3662 | SV0-0000-C0W-862928 | 300 SERIES BUILDINGS SMALL TRANSFORMER FOUNDATIONS |
| 3663 | SV3-1120-EJW-862943 | FABRICATION & INSTALLATION OF DESIGN JUNCTION BOX / CONDUIT SUPPORTS IN ROOM 11208 |
| 3664 | SV4-DWS-THW-862256 | DWS PRESSURE TEST |
| 3665 | SV4-CAS-P0W-855038 | INSTALL PIPE AND SUPPORTS FOR ISO SV4-CAS-PLW-843 |
| 3666 | SV4-DWS-P0W-855008 | SMALL BORE PIPE ISO SV4-DWS-PLW-725 & SUPPORTS |
| 3667 | SV4-VWS-P0W-855009 | LARGE BORE PIPE ISO. SV4-VWS-PLW-50A, CONTAINMENT RM 11702 |
| 3668 | SV4-VWS-P0W-855023 | INSTALL LARGE BORE PIPE SV4-VWS-PLW-532 |
| 3669 | SV4-VWS-PHW-855018 | CONTAINMENT BUILDING- INSTALLATION OF SUPPORTS ISO SV4-VWS-PLW-50Y |
| 3670 | SV3-WWS-PHW-860661 | FABRICATION AND INSTALLATION OF WWS PIPING SUPPORTS |
| 3671 | SV4-WRS-P0W-862456 | INSTALLATION OF ANNEX BLDG WRS PIPING (ISO SV4-WRS-PLW-454, 455, 464, 465, 466, 467, 469 & 474) |
| 3672 | SV4-DWS-P0W-861602 | INSTALLATION OF ANNEX BLDG DWS PIPING (ISO SV4-DWS-PLW-130 & 131) |
| 3673 | SV4-MSS-PHW-860361 | INSTALLATION AND FABRICATION OF MAIN STEAM SYSTEM (MSS) PIPING SUPPORTS |
| 3674 | SV3-2053-SHW-862021 | ELECTRICAL CABLE TRAY SUPPORTS FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 141'3", AREA 3 |
| 3675 | SV3-ZAS-ERW-EL3253 | INSTALL CABLE TRAY & RACEWAY FOR UNIT AUX. TRANSFORMER ZAS-ET-2C, IN TRANSFORMER AREA NORTH OF TURBINE BUILDING. |
| 3676 | SV3-1231-C0W-850000 | 100' ELEV, FLOOR SLAB AREA 1 (SP-17) |
| 3677 | SV3-2033-SHW-862395 | ELECTRICAL CABLE TRAY WELDED SUPPORTS FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 100'0" , AREA 3 |
| 3678 | SV3-1231-ERW-861084 | Install Electrical Penetration Sleeves for Interior and Exterior Walls EL 100'-0" to 117'-6", Area 1, Unit 3 AUX |
| 3679 | SV3-2053-SHW-862688 | INSTALLATION OF BUSS DUCT SUPPORTS IN TURBINE BUILDING (ELEV. 141'3" AREA 3) (ROOM 20502) |
| 3680 | SV3-1232-C0W-850000 | 100' Elev., Floor Slab Area 2, (SP-18) |
| 3681 | SV4-CAS-P0W-850083 | SMALL BORE PIPE ISO SV4-CAS-PLW-83H & SUPPORTS |
| 3682 | SV3-2053-SHW-862687 | INSTALLATION OF BUSS DUCT SUPPORTS IN TURBINE BUILDING (ELEV. 141'3" AREA 3) ROMM 20501 |
| 3683 | SV4-4030-C0W-850009 | UNIT 4 ANNEX BUILDING AREA 3 SLAB AT ELEV. 107'-3" REINFORCING STEEL |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3684 | SV3-4000-SHW-862382 | FABRICATION AND INSTALLATION OF TYPICAL FIELD ROUTED CONDUIT SUPPORTS, DETAIL C-70, ANNEX BUILDING, ALL AREAS / ELEVATIONS BOOK 1 |
| 3685 | SV3-4031-SHW-861530 | FABRICATE AND INSTALL CABLE TRAY SUPPORTS ANNEX BLDG. AREA 1, ELEV. 100¿, BETWEEN COLUMN LINES 11.09/11.15 & E/G. |
| 3686 | SV4-4031-ERW-862034 | INSTALLATION OF CONDUIT PENETRATION SLEEVES, ANNEX BUILDING, AREA 1, ELEV. 100'-0" |
| 3687 | SV4-4032-ERW-862035 | INSTALLATION OF CONDUIT PENETRATION SLEEVES, ANNEX BUILDING, AREA 2 ELEV. 100'-0" |
| 3688 | SV3-4000-SHW-862354 | FABRICATION AND INSTALLATION OF TYPICAL FIELD ROUTED CONDUIT SUPPORTS, DETAIL C-204, ANNEX BUILDING, ALL AREAS/ ELEVATIONS BOOK 1 |
| 3689 | SV3-TDS-P0W-860846 | INSTALLATION AND FABRICATION OF TURBINE ISLAND DRAINS VENTS AND RELEIF SYSTEM (TDS) PIPING |
| 3690 | SV3-MH01-EYW-862916 | UNIT 3 CONTAINMENT POLAR CRANE RUNWAY MAINLINE SUPPORTS AND MAINLINE CONDUCTOR BAR ASSEMBLIES |
| 3691 | SV3-4031-SHW-861535 | FABRICATE AND INSTALL CABLE TRAY SUPPORTS ANNEX BLDG. AREA 1, ELEV. 100¿, BETWEEN COLUMN LINES 11.15/13 & F/G. |
| 3692 | SV3-4000-SHW-862384 | FABRICATION AND INSTALLATION OF TYPICAL FIELD ROUTED CONDUIT SUPPORTS, DETAIL C-82, ANNEX BUILDING, ALL AREAS/ ELEVATION BOOK 1 |
| 3693 | SV3-4031-SHW-861534 | FABRICATE AND INSTALL CABLE TRAY SUPPORTS ANNEX BLDG. AREA 1, ELEV. 100¿, BETWEEN COLUMN LINES 11.15/13 & G/H. |
| 3694 | SV3-ML05-MLW-860960 | Installation of Pipe Penetrations 117'-135' South Shield Wall |
| 3695 | SV3-RNS-PHW-861876 | ASME SECTION III – FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-RNS-PLW-015 |
| 3696 | SV4-PXS-P0W-850430 | INSTALL ISOMETRIC SV4-PXS-PLW-430 |
| 3697 | SV4-CA01-S4W-862815 | CA01 BASEMAT SA7 INSTALLATION |
| 3698 | SV4-ME01-MEW-862758 | UNIT 4 CONDENSERS A, B & C: INSTALLATION OF UPPER SHELL MANHOLES |
| 3699 | SV3-1237-SHW-860350 | INSTALL CONDUIT SUPPORTS ON SHIELD WALL AZ-225¿ TO AZ-270 ¿ 100'-0" |
| 3700 | SV3-CA37-ERW-861473 | FABRICATION AND INSTALLATION OF ELECTRICAL PENETRATIONS IN THE CA37 MODULE |
| 3701 | SV3-CA20-ERW-EL7472 | MODULE CA20 UNIT, SUB-ASSEMBLY I AND II EL. 66'6" TO 92'6", INSTALL DESIGNED CABLE TRAYS AND SUPPORTS |
| 3702 | SV4-RNS-P0W-861622 | ASME III FABRICATION/INSTALLATION OF CA20 LARGE BORE PIPING FOR ISOMETRIC SV4-RNS-PLW-09A |
| 3703 | SV3-PXS-MYW-862725 | FABRICATION/INSTALLATION OF 2A CONTAINMENT RECIRCULATION SCREEN |
| 3704 | SV3-MG01-MEW-862024 | STEAM TURBINE WELDING |
| 3705 | SV3-CA56-S5W-862415 | CA56 MODULE FABRICATION |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3706 | SV4-WWS-P0W-862701 | INSTALLATION AND FABRICATION OF WASTE WATER SYSTEM (WWS) PIPING ON 158'7" AND 156'0" SLABS |
| 3707 | SV4-1208-C0W-850005 | UNIT 4 AUXILIARY EL 100' CYLINDRICAL WALLS CIVIL RC05A AND B |
| 3708 | SV4-ML05-MLW-862027 | INSTALLATION OF UNIT 4 CA20 FLOOR PENETRATIONS |
| 3709 | SV3-PXS-MYW-862726 | FABRICATION/INSTALLATION OF 2B CONTAINMENT RECIRCULATION SCREEN |
| 3710 | SV3-1154-SHW-800000 | Fabricate and Install Welded conduit supports in Containment Area 4 Elev. 135'3" |
| 3711 | SV3-CDS-PHW-860478 | INSTALLATION OF CDS SUPPORTS FOR ISOs SV3-CDS-PLW-730, 731, 732, 733 AND 734 |
| 3712 | SV4-CA01-S4W-862914 | CA01 SA07 ELEV 107'-119' OVERLAY PLATES (OLPS) |
| 3713 | SV4-WWS-PHW-862813 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR UNIT 4 TRANSFORMER AREA SUMP SV4-WWS-MTW-010 |
| 3714 | SV4-ME01-PLW-861893 | UNIT 4 CONDENSER C: FABRICATION & INSTALLATION OF 3RD EXTRACTION STEAM PIPING |
| 3715 | SV4-ME01-PLW-861894 | UNIT 4 CONDENSER C: FABRICATION & INSTALLATION OF 4TH EXTRACTION STEAM PIPING |
| 3716 | SV4-ME01-PLW-861891 | UNIT 4 CONDENSER C: FABRICATION & INSTALLATION OF 1ST EXTRACTION STEAM PIPING |
| 3717 | SV4-ME01-PLW-861892 | UNIT 4 CONDENSER C: FABRICATION & INSTALLATION OF 2ND EXTRACTION STEAM PIPING |
| 3718 | SV4-ME01-PLW-861888 | UNIT 4 CONDENSER B: FABRICATION & INSTALLATION OF 2ND EXTRACTION STEAM PIPING |
| 3719 | SV3-1234-ERW-862935 | INSTALL CONDUIT SLEEVES FOR PENETRATIONS IN PRECAST CONCRETE PANELS SV3-1234-CP-S01 TO SV3-1234-CP-S03 UNIT 3 AUXILIARY BUILDING ELEV 92'-6" AREA 4 |
| 3720 | SV0-0000-XEW-CV0868 | Trench/Excavation For Commodity Installation in Non-Safety Areas (All NOI-s) |
| 3721 | SV0-PWS-THW-ME2056 | HYDRO TEST THE HDPE PORTION OF THE POTABLE WATER SYSTEM (PWS) |
| 3722 | SV3-0150-ERW-EL2314 | INSTALLATION OF CONDUUIT SLEEVES FOR PENETATION IN UNIT 3 TRANSFORMER AREA |
| 3723 | SV3-1110-ERW-EL1532 | U3-CONTAINMENT CONDUIT SUPPORTS ROOM 11104 AND EL 71'6" TO 84'-6" |
| 3724 | SV3-1220-EGW-EL2411 | INSTALL GROUNDING GRID AND FLOOR PLATES FOR 82'-6" SLAB AREAS 4,5 & 6 |
| 3725 | SV3-4034-EGW-EL2353 | PERFORM INSTALLATION OF UNDERGROUND COMMODITIES (EGS-GROUNDING) FOR THE ANNEX BLDG., AREA 4, ELEV.100'- BETWEEN COLUMN LINES (7.9) TO (15.2) |
| 3726 | SV3-4034-ERW-EL2352 | PERFORM INSTALLATION OF UNDERGROUND COMMODITIES (EMBEDDED CONDUIT) FOR THE ANNEX BLDG., AREA 4, 100' - BETWEEN COLUMN LINES (7.9) TO (15.2). |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3727 | SV3-6000-EGW-EL2317 | PERFORM INSTALLATION OF UNDERGROUND GROUNDING COMMODITIES DIESEL GENERATOR BUILDING AREA 1 & 2 ELEVATION 100' BETWEEN COLUMN LINES (BD) & (AAD) |
| 3728 | SV3-CA01-CRW-CV2290 | FABRICATION OF REBAR FOR CA01 MODULE |
| 3729 | SV3-CPS-PHW-ME2122 | FABRICATION AND INSTALLATION OF CPS PIPING SUPPORTS FROM ELEVATION 100'-0" TO SUMPS SV3-WWS-MT-09A&B |
| 3730 | SV3-DTS-PHW-ME1516 | FABRICATE AND INSTALL DEMINERALIZED WATER TREATMENT SYSTEM (DTS) SUPPORTS PORTION 2 - (RAW WATER SUPPLY TO DTS-MS-01) |
| 3731 | SV3-ML10-MLW-ME2123 | PLACEMENT OF CONTAINMENT PENETRATIONS P19, P20, P22 |
| 3732 | SV3-MS60-MEW-ME1676 | INSTALLATION OF AUXILIARY BOILER DEAERATOR (ASS-ME-01) |
| 3733 | SV3-WRS-PLW-ME4468 | CA20 LEAK CHASE TESTING PROCEDURE FOR CHANNELS CONNECTING TO THE SPENT FUEL POOL (FHS-MT-01) |
| 3734 | SV3-WWS-PLW-ME1345 | WWS LINE TO WWRB'S |
| 3735 | SV0-0000-EGW-EL3556 | PERFORM INSTALLATION OF UNDERGROUND COMMODITIES (SV0 SITE STATION GROUNDING GRID) FOR GROUND GRID AREA K1200 |
| 3736 | SV0-010-ERW-EL6243 | Supplemental Steel Beam Installation for Cable Tray Supports @ 315 Bldg. |
| 3737 | SV3-0000-CCW-CV7067 | Concrete and Rebar for Diesel and Electric-Driven Fire Pump Enclosure Foundation |
| 3738 | SV3-1103-ERW-EL5391 | 11208 RNS VALVE ROOM X CONDUITS |
| 3739 | SV4-WLS-MTW-ME1805 | WLS CHEMICAL WASTE TANK INSTALLATION |
| 3740 | SV4-WLS-P0W-ME1910 | FABRICATE AND INSTALL WLS EMBEDDED PIPING SHOWN ON ISOMETRIC DRAWING SV4-WLS-PLW-752. |
| 3741 | SV4-WLS-P0W-ME1911 | FABRICATE AND INSTALL WLS EMBEDDED PIPING SHOWN ON ISOMETRIC DRAWING SV4-WLS-PLW-753. |
| 3742 | SV4-WLS-P0W-ME1912 | FABRICATE AND INSTALL WLS EMBEDDED PIPING SHOWN ON ISOMETRIC DRAWING SV4-WLS-PLW-755. |
| 3743 | SV4-WLS-P0W-ME1913 | FABRICATE AND INSTALL WLS EMBEDDED PIPING SHOWN ON ISOMETRIC DRAWING SV4-WLS-PLW-756. |
| 3744 | SV4-WLS-P0W-ME1914 | FABRICATE AND INSTALL WLS EMBEDDED PIPING SHOWN ON ISOMETRIC DRAWING SV4-WLS-PLW-758. |
| 3745 | SV4-WLS-P0W-ME1915 | FABRICATE AND INSTALL WLS EMBEDDED PIPING SHOWN ON ISOMETRIC DRAWING SV4-WLS-PLW-759. |
| 3746 | SV4-WLS-P0W-ME1916 | FABRICATE AND INSTALL WLS EMBEDDED PIPING SHOWN ON ISOMETRIC DRAWING SV4-WLS-PLW-75C. |
| 3747 | SV4-WLS-P0W-ME1917 | FABRICATE AND INSTALL WLS EMBEDDED PIPING SHOWN ON ISOMETRIC DRAWING SV4-WLS-PLW-75E. |
| 3748 | SV4-WLS-P0W-ME1918 | FABRICATE AND INSTALL WLS EMBEDDED PIPING SHOWN ON ISOMETRIC DRAWING SV4-WLS-PLW-785. |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3749 | SV4-WLS-P0W-ME1935 | ASME SECTION III - FABRICATE AND INSTALL WLS EMBEDDED PIPING SHOWN ON ISOMETRIC DRAWING SV4-WLS-PLW-730 |
| 3750 | SV4-WLS-P0W-ME1936 | ASME SECTION III - FABRICATE AND INSTALL WLS EMBEDDED PIPING SHOWN ON ISOMETRIC DRAWING# SV4-WLS-PLW-740 |
| 3751 | SV4-WLS-P0W-ME1937 | ASME SECTION III - FABRICATE AND INSTALL WLS EMBEDDED PIPING SHOWN ON ISOMETRIC DRAWING# SV3-WLS-PLW-751 |
| 3752 | SV4-WLS-P0W-ME3113 | INSTALLATION OF LARGE BORE WLS PIPING (INCLUDES ISOMETRIC SV4-WLS-PLW-071) |
| 3753 | SV4-WLS-P0W-ME3115 | INSTALLATION OF LARGE BORE WLS PIPING LINES WLS-PL-L079 & L131C OF ISOMETRIC SV4-WLS-PLW-741 |
| 3754 | SV4-WRS-P0W-ME4626 | WRS BASEMAT PIPING CLEANLINESS/FME REPAIR |
| 3755 | SV4-WRS-P0W-ME5329 | FABRICATION/INSTALLATION OF SMALL BORE WRS LEAK CHASE PIPING INCLUDING SV4-WRS-PLW-86G, 86H, 800 |
| 3756 | SV4-WRS-P0W-ME6689 | WRS EMBEDDED PIPING INSTALLATION (INCLUDING ISOMETRIC SV4-WRS-PLW-521, 52N, 52M, 52L) |
| 3757 | SV4-WRS-PLW-ME1574 | INSTALLATION OF LARGE BORE WRS PIPING (INCLUDES ISOMETRICS SV4-WRS-PLW-573, 655) |
| 3758 | SV4-WRS-PLW-ME1575 | WRS LARGE BORE PIPING INSTALLATION (INCLUDES ISOMETRIC SV4-WRS-PLW-57P, 57L, AND 57K) |
| 3759 | SV4-WRS-PLW-ME1577 | INSTALLATION OF LARGE BORE WRS PIPING ( INCLUDES ISOMETRIC SV4-WRS-PLW-57J) |
| 3760 | SV4-WRS-PLW-ME1578 | INSTALLATION OF LARGE BORE WRS PIPING ( INCLUDES ISOMETRICS SV4-WRS-PLW-572, 574, 578, 57D, 579) |
| 3761 | SV4-WRS-PLW-ME1579 | INSTALLATION OF LARGE BORE WRS PIPING (INCLUDES ISOMETRICS SV4-WRS-PLW-57B, 575, 57E) |
| 3762 | SV4-WRS-PLW-ME1580 | INSTALLTION OF LARGE BORE WRS PIPING (INCLUDES ISOMETRICS SV4-WRS-PLW-571, 576, 57F) |
| 3763 | SV4-WRS-PLW-ME1763 | INSTALLATION OF LARGE BORE WRS PIPING (INCLUDES ISOMETRICS SV4-WRS-PLW-52A, -52B, -52D, -52F) |
| 3764 | SV4-WRS-PLW-ME1764 | INSTALLATION OF LARGE BORE WRS PIPING (INCLUDES ISOMETRICS SV4-WRS-PLW-53D) |
| 3765 | SV4-WRS-THW-ME2413 | HYDROSTATIC TESTING FOR RADIOACTIVE WASTE DRAIN SYSTEM (WRS) |
| 3766 | SV4-WWS-ERW-EL0863 | INSTALLATION OF ELECTRICAL UNDERGROUND COMMODITIES (MANHOLES AND DUCT BANKS) FOR THE (WWS) WASTE WATER SYSTEM |
| 3767 | SV4-WWS-P0W-ME1977 | WWS EMBEDDED PIPING INSTALLATION (INCLUDING ISOMETRIC SV3-WWS-PLW-31B, & 31F) |
| 3768 | SV4-WWS-P0W-ME2703 | WWS EMBEDDED PIPING INSTALLATION (INCLUDING ISOMETRIC SV3-WWS-PLW-310, 31E, 319, & 31A) |
| 3769 | SV4-WWS-P0W-ME3097 | WWS EMBEDDED PIPING INSTALLATION (INCLUDING ISOMETRIC SV4-WWS-PLW-020) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3770 | SV4-WWS-P0W-ME3187 | WWS EMBEDDED PIPING INSTALLATION (INCLUDING ISOMETRICS SV4-WWS-PLW-321 & 322) |
| 3771 | SV4-WWS-P0W-ME3348 | WWS EMBEDED PIPING INSTALLATION (INCLUDING ISOMETRICS SV4-WWS-PLW-32C, -32E, -32F, -32G) |
| 3772 | SV4-WWS-P0W-ME4625 | WWS BASEMAT PIPING CLEANLINESS/FME REPAIR |
| 3773 | SV4-WWS-P0W-ME5467 | FABRICATION AND INSTALLATION OF WWS PIPING |
| 3774 | SV4-WWS-P0W-ME6622 | WWS EMBEDED PIPING INSTALLATION (INCLUDING ISOMETRICS SV4-WWS-PLW-334) |
| 3775 | SV4-WWS-P0W-ME7165 | FABRICATE AND INSTALL THE WASTE WATER PIPING ON THE EAST SIDE OF THE U4 TURBINE BUILDING IN PHASE 7. |
| 3776 | SV4-WWS-PHW-ME5481 | INSTALLATION OF PIPE SUPPORTS FOR PIPING PACKAGE SV4-WWS-P0W-ME5467 |
| 3777 | SV4-WWS-PLW-ME1646 | UNIT 4 TURBINE BUILDING EL 100-0 FIRST BAY EMBEDDED WWS PIPING PACKAGE # 1, |
| 3778 | SV4-WWS-PLW-ME1647 | UNIT 4 TURBINE BUILDING EL 100-0 FIRST BAY EMBEDDED WWS PIPING PACKAGE # 2 |
| 3779 | SV4-WWS-PLW-ME1648 | UNIT 4 TURBINE BUILDING EL 100'-0": EMBEDDED WWS PIPING PACKAGE # 3 |
| 3780 | SV4-WWS-PLW-ME1650 | UNIT 4 TURBINE BUILDING EL 100'-0": EMBEDDED WWS PIPING PACKAGE # 5 |
| 3781 | SV4-WWS-PLW-ME1765 | INSTALLATION OF LARGE BORE WWS PIPING (INCLUDING ISOMETRICS SV4-WWS-PLW-311, -315) |
| 3782 | SV3-2053-ERW-861823 | ELECTRICAL CABLE TRAY RACEWAY FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEV 141'3" AREA 3 |
| 3783 | SV3-2052-ERW-861853 | ELECTRICAL CABLE TRAY RACEWAY FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 141'3", AREA 2 |
| 3784 | SV3-2057-ERW-861986 | INSTALLATION OF CABLE TRAY RACEWAY IN TURBINE BUILDING (ELEV. 141'3" AREA 7) |
| 3785 | SV3-2057-ERW-861990 | INSTALLATION OF CABLE TRAY RACEWAY COVERS IN TURBINE BUIDLING (ELEV. 141'3" AREA 7) |
| 3786 | SV3-4000-SHW-862357 | FABRICATION AND INSTALLATION OF TYPICAL FIELD ROUTED CONDUIT SUPPORTS, DETAILS C-189, ANNEX BUILDING, ALL AREAS/ ELEVATIONS. BOOK 1 |
| 3787 | SV3-WLS-P0W-800002 | Install Small Bore Piping per Isometric SV3-WLS-PLW-531 |
| 3788 | SV3-WLS-PHW-800002 | Install Small Bore Supports per Isometric SV3-WLS-PLW-532 |
| 3789 | SV4-2000-SSW-CV3930 | TURBINE BLDG. HOUSE STEEL IN-PROCESS REPAIR/REWORK (SEQ6-SEW11) |
| 3790 | SV4-2020-MEW-ME1150 | UNIT 4 CONDENSER A FLASH BOX ASSEMBLY |
| 3791 | SV4-2030-SSW-CV3967 | UNIT 4 TURBINE BUILDING SEQUENCE 6 HANDRAIL AND STAIRS |
| 3792 | SV4-2030-SSW-CV3968 | UNIT 4 TURBINE BUILDING SEQUENCE 6 GRATING AND DECKING |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3793 | SV4-CWS-P0W-ME3243 | INSTALLATION OF CWS PIPING RISERS (RETURN SIDE) |
| 3794 | SV4-CWS-PLW-ME0551 | UNIT 4 CWS PIPING FROM NUCLEAR ISLAND TO COOLING TOWER |
| 3795 | SV4-ME01-PLW-ME1006 | UNIT 4 CONDENSER B: INSTALLATION OF UPPER SHELL NOZZLES |
| 3796 | SV4-WLS-P0W-ME3117 | INSTALLATION OF LARGE BORE WLS PIPING (INCLUDES ISOMETRIC SV4-WLS-PLW-754) |
| 3797 | SV4-WRS-P0W-ME1974 | INSTALLATION OF LARGE BORE WRS PIPING ( INCLUDES ISOMETRIC SV4-WRS-PLW-66A, 66C, 66E, 662, 667) |
| 3798 | SV4-WRS-PLW-ME1576 | INSTALLATION OF LARGE BORE WRS PIPING ( INCLUDES ISOMETRICS SV4-WRS-PLW-57M AND 57N ) |
| 3799 | SV3-SDS-PHW-ME2544 | INSTALLATION OF ANNEX SDS SUPPORTS (FOR WP SV3-SDS-P0W-ME2415) |
| 3800 | SV3-SDS-PHW-ME2545 | INSTALLATION OF ANNEX SDS SUPPORTS (FOR WP SV3-SDS-P0W-ME2416) |
| 3801 | SV3-SDS-PHW-ME2546 | Installation of Annex SDS Supports (For WP SV3-SDS-P)W-ME2417) |
| 3802 | SV4-2000-Z0W-CV1908 | UNIT 4 TURBINE BUILDING REINFORCED CONCRETE REQUIREMENTS |
| 3803 | SV3-SDS-PHW-ME2547 | INSTALLATION OF ANNEX SDS SUPPORTS (FOR WP SV3-SDS-P0W-ME2418) |
| 3804 | SV3-SDS-THW-ME2196 | HYDRO TESTING OF THE UNIT 3 ANNEX BUILDING SANITARY DRAINAGE SYSTEM |
| 3805 | SV3-SFS-P0W-ME2188 | ASME SECTION III - INSTALLATION OF R365 COMMODITIES |
| 3806 | SV3-SFS-P0W-ME3644 | INSTALLATION OF LARGE BORE SFS PIPING (INCLUDES ISOMETRIC SV3-SFS-PLW-12C) |
| 3807 | SV3-SS01-Z0W-CV4381 | UNIT 3 STRUCTURAL STEEL SAFETY CLASS C REQUIREMENTS |
| 3808 | SV3-SWS-P0W-ME2158 | FABRICATION AND INSTALLATION OF SWS PIPING IN ROOM 20309 (ISOMETRICS SV3-SWS-PLW-051, 052, 062, 063, &064) |
| 3809 | SV3-SWS-P0W-ME2159 | FABRICATION AND INSTALLATION OF SWS PIPING IN ROOM 20309 (ISOMETRICS SV3-SWS-PLW-041, 042, 060, & 061) |
| 3810 | SV3-SWS-P0W-ME6784 | Service Water System (SWS) Piping Installation in Phase 3A |
| 3811 | SV3-SWS-PHW-ME1504 | INSTALLATION OF SWS LARGE BORE PIPING SUPPORTS FOR PIPING INCLUDED IN THE SV3-SWS-PLW-ME1495 WORK PACKAGE |
| 3812 | SV3-SWS-PHW-ME1505 | INSTALLATION OF SWS LARGE BORE PIPING SUPPORTS FOR PIPING INCLUDED IN THE SV3-SWS-PLW-ME1496 WORK PACKAGE |
| 3813 | SV3-SWS-PLW-ME1497 | INSTALLATION OF SWS LARGE BORE PIPING (INCLUDES ISOMETRICS SV3-SWS-PLW-090, 091, 092, 093, 094, 095) |
| 3814 | SV3-TCS-PLW-ME2389 | INSTALLATION OF TCS PIPING (INCLUDES ISOMETRICS SV3-TCS-PLW-710, 711,712,71Y,703,704, & 71B) |
| 3815 | SV3-VAS-MDW-ME5775 | INSTALLATION OF HVAC DUCT PIECES AND SUPPORTS IN ROOMS 12166, 12167 & 12268 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3816 | SV3-VWS-P0W-ME5325 | ANNEX - Initial Energization Piping - Iso 171, 180, 181, 190, 191, & 197 |
| 3817 | SV3-VWS-PHW-ME2796 | INSTALLATION OF VWS SUPPORTS FOR ISOMETRICS SV3-VWS-PLW-10P |
| 3818 | SV3-WGS-P0W-ME2725 | INSTALLATION OF SMALL BORE WGS PIPING (INCLUDES SV3-WGS-PLW-020) |
| 3819 | SV3-WGS-P0W-ME2726 | INSTALLATION OF SMALL BORE WGS PIPING (INCLUDES SV3-WGS-PLW-421) |
| 3820 | SV3-WGS-PHW-ME2807 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWINGS SV3-WGS-PLW-050, 101, 103, 105, 107 |
| 3821 | SV3-WGS-PHW-ME2809 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWINGS SV3-WGS-PLW-546 |
| 3822 | SV3-WGS-PHW-ME2811 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWINGS SV3-WGS-PLW-421 |
| 3823 | SV3-WGS-PHW-ME2812 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWINGS SV3-WGS-PLW-544 |
| 3824 | SV3-WLS-P0W-ME2990 | INSTALLATION OF SMALL BORE WLS PIPING ON R104 MODULE |
| 3825 | SV3-WLS-P0W-ME3388 | INSTALLATION OF SMALL BORE WLS PIPING (ISOMETRIC SV3-WLS-PLW-040) |
| 3826 | SV3-WLS-PLW-ME0510 | INSTALLATION OF SMALL BORE WLS PIPING (INCLUDES ISOMETRIC SV3-WLS-PLW-060) |
| 3827 | SV3-WLS-PLW-ME0938 | Fabricate and Install Small Bore Elevation 1 WLS Piping Iso SV3-WLS-PLW-051 |
| 3828 | SV3-WLS-PLW-ME2478 | FABRICATE AND INSTALL ISOMETRIC DRAWING# SV3-WLS-PLW-741 |
| 3829 | SV3-WLS-PLW-ME3091 | FABRICATION/INSTALLATION OF SMALL BORE WLS PIPING FOR ISOMETRIC SV3-WLS-PLW-35K |
| 3830 | SV3-WLS-THW-ME2910 | HYDRO TEST THE UNIT 3 LIQUID RADWASTE SYSTEM PIPING PHASE 5 |
| 3831 | SV3-WRS-P0W-ME2348 | ANNEX BUILDING - ELEV 100 WRS PIPING PACKAGE #2 |
| 3832 | SV3-WRS-P0W-ME2349 | ANNEX BUILDING - ELEV 136 WRS PIPING PACKAGE |
| 3833 | SV3-WRS-P0W-ME2450 | Fabrication and Installation of Small Bore WRS Piping (Isometric SV3-WRS-PLW-57Q) |
| 3834 | SV3-WRS-P0W-ME2490 | FABRICATION AND INSTALLATION OF LARGE BORE WRS PIPING (ISOMETRIC SV3-SRS-PLW-650) |
| 3835 | SV3-WRS-P0W-ME4428 | INSTALLATION OF SMALL BASE WRS PIPING (INCLUDES ISOMETRICS SV3-WRS-PLW-86C, SV3-WRS-PLW-809 |
| 3836 | SV3-WRS-P0W-ME6720 | WRS EMBEDDED PIPING INSTALLATION (INCLUDING ISOMETRIC SV3-WRS-PLW-521, 52N, 52M, 52L) |
| 3837 | SV3-SWS-PHW-ME1503 | INSTALLATION OF SWS LARGE BORE PIPING SUPPORTS FOR PIPING INCLUDED IN THE SV3-SWS-PLW-ME1494 WORK PACKAGE |
| 3838 | SV4-2000-SUW-CV3226 | TURBINE BLDG.STEEL IN-PROCESS REPAIR/REWORK (CH80,CH81,&CH82) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3839 | SV3-1120-ERW-EL3067 | Fabrication and Installation of non-scheduled, Detail C14 conduit supports in Unit 3 Containment Building. Seismic category II. WP1 |
| 3840 | SV3-1120-ERW-EL3069 | Fabrication and Installation of non-scheduled, Detail C15 conduit supports in Unit 3 Containment Building. Seismic category II. WP1 |
| 3841 | SV3-WRS-PHW-ME3032 | INSTALLATION OF SMALL BORE WRS PIPE SUPPORTS ON R104 MODULE |
| 3842 | SV4-G100-XEW-CV0628 | Unit 4 Vertical Waterproofing Membrane |
| 3843 | SV3-1110-CEW-CV2053 | INSTALLATION OF UNIT 3 STEAM GENERATOR COLUMN PEDESTAL EMBEDMENTS |
| 3844 | SV3-1120-EGW-EL2181 | GROUNDING OF THE CONTAINMENT BUILDING AT ELEVATION 82'-6" TO 100' |
| 3845 | SV3-2000-SUW-CV1571 | RE-WORK OF CH81 STRUCTURAL STEEL |
| 3846 | SV4-2030-CCW-CV0383 | UNIT 4 TURBINE BULIDING 100 FT ELEV.SLAB MUDMAT ( INCLUDES THE 1ST BAY) |
| 3847 | SV4-2030-CCW-CV0384 | U4 Turbine Building 82’-9” to 100’ Elevation Walls |
| 3848 | SV3-1220-EGW-EL2176 | INSTALL GROUNDING GRID AND FLOOR PLATES FOR 82'-6" SLAB AREAS 1, 2 & 3 |
| 3849 | SV3-1133-SSW-CV6172 | SPL44 INSTALLATION |
| 3850 | SV3-1220-EGW-EL3099 | U3-AUXILIARY BUILDING INSTALL ELECTRICAL PENETRATIONS AND GROUNDING FOR AREAS 3 & 4, WALLS # 41, 48, 49, 50, 51, & 52 EL82' 6" TO 100' 0" |
| 3851 | SV3-1220-EGW-EL3100 | U3-AUXILIARY BUILDING INSTALL ELECTRICAL PENETRATIONS AND GROUNDING FOR AREAS 5 & 6, EL 82' 6" TO 100' 0" |
| 3852 | SV3-2060-EGW-EL3271 | ELECTRICAL GROUNDING INSTALLATION FOR THE TURBINE BUILDING AT ELEVATIONS 170'-0", 196'-3" AND 230'-9". |
| 3853 | SV3-ASS-PHW-ME1526 | FABRICATE/INSTALL OF AUXILIARY STEAM (ASS) SUPPORTS (PORTION 4) FOR ISOMETRIC# SV3-ASS-PLW-023, 02B, & 02U |
| 3854 | SV3-WRS-P0W-ME4424 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES ISOMETRICS SV3-WRS-PLW-802, -80X, -80Y |
| 3855 | SV4-RNS-P0W-861625 | ASME III FABRICATION/INSTALLATION OF CA20 LARGE BORE PIPING FOR ISOMETRIC SV4-RNS-PLW-161 |
| 3856 | SV3-2000-P0W-ME6769 | INSTALLATION OF TEMPORARY FIRE PROTECTION SYSTEM STANDPIPE |
| 3857 | SV3-2033-SHW-EL6790 | Electrical Cable Tray Supplemental Steel Installation in the Turbine Building, Elevation 100’-0”, Area 3 from Columns 18 to 19 & P.2 to R |
| 3858 | SV3-2037-SHW-EL6766 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE TURBINE BUILDING FOR ELEV 100'-0" AREA 7 FROM COLUMNS 18 TO 19 AND 1.2 TO K.1 |
| 3859 | SV3-CAS-PHW-ME2788 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-CAS-PLW-83H |
| 3860 | SV3-CVS-P0W-ME2656 | INSTALLATION OF SMALL BORE CVS PIPING (INCLUDES ISOMETRIC: SV3-CVS-PLW-102) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3861 | SV3-ME01-PHW-ME1536 | Unit 3 Condenser A: Installation of Water Curtain Spray Piping Supports |
| 3862 | SV3-R161-ERW-EL4153 | INSTALLATION OF ELECTRICAL CABLE TRAY IN MODULE R161 |
| 3863 | SV4-1010-CRW-CV1271 | Installation of Unit 4 Nuclear Island Basemat Reinforcement Below Containment Vessel |
| 3864 | SV4-1120-CRW-CV3171 | Unit 4 Containment Concrete Reinforcement El. 76'-6" to El. 80'-0" & El. 80'-6"" |
| 3865 | SV4-2030-CCW-CV0386 | Unit 4, Turbine Building, 100' elevation elevated slabs |
| 3866 | SV4-ASS-P0W-ME5420 | Fabricate and Install Auxiliary Steam System(ASS) Piping |
| 3867 | SV4-ASS-P0W-ME5422 | Installation and Fabrication of Auxiliary Steam System (ASS) Piping Portion 2 |
| 3868 | SV4-ASS-P0W-ME5423 | Installation and Fabrication of Auxiliary Steam Supply System(ASS) Piping Portion 3 |
| 3869 | SV3-4000-SHW-862381 | FABRICATION AND INSTALLATION OF TYPICAL ROUTED CONDUIT SUPPORTS DETAIL C-89 ANNEX BUILDING ALL AREAS/ELEVATIONS BOOK 1 |
| 3870 | SV3-4000-SHW-862356 | FABRICATION AND INSTALLATION OF TYPICAL FIELD ROUTED CONDUIT SUPPORTS DETAIL C-203 ANNEX BUILDING ALL AREAS ELEVATIONS BOOK 1 |
| 3871 | SV3-4000-SHW-862355 | FABRICATION AND INSTALLATION OF TYPICAL FIELD ROUTED CONDUIT SUPPORTS DETAIL C-102 ANNEX BUILDING ALL AREAS ELEVATIONS BOOK 1 |
| 3872 | SV3-4031-SHW-861533 | FABRICATE AND INSTALL CABLE TRAY SUPPORTS ANNEX BLDG. AREA 1, ELEV. 100¿, WEST OF BATTERY CHARGER ROOMS, BETWEEN COLUMN LINES 10.05/11.09. |
| 3873 | SV3-2030-PLW-ME1199 | INSTALL PIPING SUPPORTS ON CONDENSATE PIPING BETWEEN CONDENSER AND UNIT 3 CONDENSATE PUMPS |
| 3874 | SV3-2030-PLW-ME1197 | INSTALL CDS PIPING FROM THE CONDENSER C OUTLET BOX TO THE UNIT 3 CONDENSATE PUMPS |
| 3875 | SV3-2141-C0W-850001 | 1ST BAY, 117'-6" ELEV, FLOOR SLAB POUR #1 |
| 3876 | SV3-2047-SHW-861712 | INSTALLATION OF WELDED CABLE TRAY SUPPORTS IN TURBINE BUILDING (ELEV. 120' 6" AREA 7) |
| 3877 | SV3-2034-SHW-861540 | Electrical Cable Tray Welded Support Fabrication and Installation in the Unit 3 Turbine Building, Elevation 100¿0¿¿, Area 4 |
| 3878 | SV3-2059-SHW-861423 | ELECTRICAL CABLE TRAY WELDED SUPPORT INSTALLATION IN THE TURBINE BUILDING, ELEVATION 141¿3¿ , AREA 9, ROOM 20500 PART 2 |
| 3879 | SV4-PH01-CEW-800000 | Unit 4, Reactor Vessel Anchor Bolt Installation and Construction Aid |
| 3880 | SV4-WLS-P0W-800021 | Install large bore pipe per SV4-WLS-PLW-800 |
| 3881 | SV4-WRS-P0W-800008 | Install large bore pipe per SV4-WRS-PLW-59M |
| 3882 | SV4-WRS-P0W-800009 | Install larger bore pipe per SV4-WRS-PLW-59Z |
| 3883 | SV3-1120-ERW-862941 | FABRICATION & INSTALLATION OF DESIGN ROUTED SUPPORTS IN ROOM 11208 |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3884 | SV3-1120-ERW-862942 | FABRICATION & INSTALLATION OF DESIGN ROUTED CONDUIT SUPPORTS IN ROOM 11208 |
| 3885 | SV0-YFS-P0W-862751 | REWORK/REPLACE FIRE HYDRANT SV0-YFS-PL-H16 |
| 3886 | SV3-SFS-PHW-862862 | ASME SECTION III – FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC SV3-SFS-PLW-780 |
| 3887 | SV4-DWS-P0W-862958 | INSTALLATION OF ANNEX BLDG DWS PIPING (ISO SV4-DWS-PLW-150) |
| 3888 | SV3-CDS-PHW-860480 | FAB & INSTALL CDS SUPPORTS FOR ISOMETRICS SV3-CDS-PLW-720, SV3-CDS-PLW-721, SV3-CDS-PLW-722, SV3-CDCS-PLW-723 & SV3-CDS-PLW-724 |
| 3889 | SV3-HDS-PHW-860535 | TURBINE BUILDING HDS PIPE SUPPORT INSTALLATION |
| 3890 | SV3-CDS-P0W-860698 | FABRICATION AND INSTALLATION OF CDS PIPING |
| 3891 | SV3-HDS-PHW-860539 | FABRICATE/INSTALL HEATER DRAIN SYSTEM PIPE SUPPORTS |
| 3892 | SV3-2044-SHW-860223 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 120'-6", AREA 4 |
| 3893 | SV3-MT71-SSW-850000 | STRUCTURAL STEEL, WASTE WATER RETENTION BASIN |
| 3894 | SV3-1152-SHW-800003 | Install Welded conduit supports in Containment Area 2 Elev. 135'3" that are associated with SP-L26, SP-L27 and SP-L28 PER Drawings SV3-1152-ER-602 and SV3-1152-ER-606 |
| 3895 | SV4-2101-CEW-862982 | UNIT4 TURBINE BUILDING FIRST BAY WALLS TO 122' PIPE PENETRATIONS |
| 3896 | SV4-CA20-S4W-800004 | 90'-3" Elev., Cask Loading Pit, Room 12463, Submodules 43 thru 46 |
| 3897 | SV3-FPS-THW-ME2720 | HYDRO TEST PACKAGE FOR UNIT 3 PHASE 2 FIRE PROTECTION SYSTEM (FPS) INCLUDING ISO'S (SV3-FPS-PLW-955 954,95AK,95AL,95AW,95AX,95BA) |
| 3898 | SV3-HDS-P0W-ME3736 | INSTALLATION AND FABRICATION OF HEATER DRAIN SYSTEM PIPING |
| 3899 | SV3-KB23-KBW-ME2688 | INSTALLATION OF KB23 COMPONENTS |
| 3900 | SV3-ML05-MLW-ME1897 | INSTALLATION OF EMBEDDED PIPING PENETRATIONS 82'-6" WALLS ONLY |
| 3901 | SV3-CVS-P0W-800002 | Install small bore pipe per SV3-CVS-PLW-512 |
| 3902 | SV3-CVS-PHW-800001 | Install small bore pipe supports per SV3-CVS-PLW-512 |
| 3903 | SV3-CVS-P0W-800003 | Install small bore pipe per SV3-CVS-PLW-521 |
| 3904 | SV3-CVS-PHW-800002 | Install small bore pipe supports per SV3-CVS-PLW-521 |
| 3905 | SV3-ML05-MLW-ME1898 | ATTACHMENT OF NELSON STUDS TO PIPING PENETRATIONS 82' 6" WALLS |
| 3906 | SV3-ML05-MLW-ME1899 | ATTACHMENT OF WELDED COUPLINGS TO PIPING PENETRATIONS 82'6" WALLS |
| 3907 | SV3-ML05-MLW-ME2048 | UNIT 3 TURBINE BUILDING EL 100'-0" PIPING PENETRATIONS |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3908 | SV3-ML05-MLW-ME2169 | INSTALLATION OF PENETRATIONS IN CA20 WALL 2 |
| 3909 | SV3-ML05-MLW-ME2170 | INSTALLATION OF PENETRATIONS IN CA20 WALLS 3 & 4 |
| 3910 | SV3-ML05-MLW-ME2637 | INSTALLATION OF ANNULUS WALL PENETRATIONS 82'6 TO 100'0 |
| 3911 | SV3-ML05-MLW-ME3946 | INSTALLATION OF CA01 ASME WALL PENETRATIONS FOR SUB-ASSEMBLY 4 |
| 3912 | SV3-ML05-MLW-ME4909 | INSTALLATION OF PENETRATION 11209-ML-118 (CA05) |
| 3913 | SV4-PV71-MEW-ME6729 | PRE-INSTALLATION WELDING OF MAIN STOP VALVE/CONTROL VALVE EQUALIZERS |
| 3914 | SV3-ML05-MLW-ME5034 | INSTALLATION OF CA01 PENETRATIONS |
| 3915 | SV3-ML05-MLW-ME6708 | CA20 WALL PENETRATIONS SEALANT |
| 3916 | SV3-MP07-MEW-ME2914 | INSTALLATION OF FWS STARTUP FEEDWATER PUMP (FWS-MP-03A) |
| 3917 | SV3-MP07-MEW-ME2915 | INSTALLATION OF FWS STARTUP FEEDWATER PUMP (FES-MP-03B). |
| 3918 | SV3-MP10-MEW-ME2773 | Installation Of TCS Turbine Bldg. Cooling Water Pumps (TCS-MP-01A & 01B) |
| 3919 | SV3-MP20-MEW-ME2366 | INSTALLATION OF HDS MSR SHELL DRAIN PUMP (HDS-MP-01A). |
| 3920 | SV3-MP20-MEW-ME2383 | INSTALLATION OF HDS MSR SHELL DRAIN PUMP (HDS-MP-01B) |
| 3921 | SV3-MS19-MEW-ME2482 | INSTALL MB CONDENSATE POLISHER (CPS-MV-01A/01B) AND CPS-MS-01A/01B) |
| 3922 | SV3-MS60-MEW-ME1679 | INSTALLATION OF AUXILIARY MOISTURE SEPARATOR (ASS-MT-08) |
| 3923 | SV3-MT6A-MEW-ME4797 | INSTALLATION OF LOS OIL STORAGE TANK (LOS-MT-02A/B) |
| 3924 | SV3-MV7H-MPW-ME6688 | INSTALLATION OF THE DEGASIFIER COLUMN (WLS-MV-01) |
| 3925 | SV3-PWS-P0W-ME4414 | FABRICATE AND INSTALL THE POTABLE WATER SUPPLY LINE TO UNIT 3 TURBINE TIE-IN |
| 3926 | SV3-PWS-PHW-ME2872 | INSTALLATION OF SMALL BORE PWS PIPING SUPPORTS FOR ISOMETRIC SV3-PW-PLW-060 |
| 3927 | SV3-PXS-P0W-ME2640 | FABRICATE AND INSTALL PXS LARGE BORE PIPING SHOWN ON ISOMETRIC DRAWINGS SV3-PXS-PLW-187, SV3-PXS-PLW-188 & SV3-PXS-PLW-189 |
| 3928 | SV3-PXS-P0W-ME2673 | Installation Of Small Bore PXS Piping (Includes Isometric: SV3-PXS-PLW-652) |
| 3929 | SV3-PXS-P0W-ME2700 | Installation of Small Bore PXS Piping (Includes Isometric: SV#-PXS-PLW-823) |
| 3930 | SV3-PXS-P0W-ME2731 | ASME SECTION III-FABRICATION/INSTALLATION OF ISOMETRIC#SV3-PXS-PLW-01E (LINE NUMBERS PXS-PL-L055A) |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3931 | SV3-PXS-P0W-ME2735 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-01R (LINE NUMBERS PXS-PL-L054A) |
| 3932 | SV3-PXS-P0W-ME2737 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-01X (LINE NUMBERS PXS-PL-L135A) |
| 3933 | SV3-PXS-P0W-ME2748 | ASME SECTION III - FABRICATION /INSTALLATION OF ISOMETRIC # SV3-PXS-PLW-02-F (LINE NUMBER PXS-PL-L055B) |
| 3934 | SV3-PXS-P0W-ME2749 | ASME Section III - Fabrication/Installation of Isometric# SV3-PXS-PLW-02M (Line Numbers PXS-PL-L056B) |
| 3935 | SV3-PXS-P0W-ME2750 | ASME Section III-Fabrication/Installation of Isometric# SV3-PXS-PLW-02Q (Line Numbers PXS-PL-L024B) |
| 3936 | SV3-PXS-P0W-ME2752 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-02S (LINE NUMBERS PXS-PL-L135B) |
| 3937 | SV3-PXS-P0W-ME2887 | ASME Section III-Fabrication/Installation of Isometric# SV3-PXS-PLW-013 (Line Numbers PXS-PL-L029A) |
| 3938 | SV3-PXS-P0W-ME2889 | ASME SECTION III- FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-015 (LINE NUMBERS PXS-PL-L151,-L112A,-L116A,-L117A |
| 3939 | SV3-PXS-P0W-ME2942 | ASME Section III - Fabrication/Installation of Isometric# SV3-PXS-PLW-200 (Line Numbers PXS-PL-L056B) |
| 3940 | SV3-PXS-P0W-ME2943 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-280 (LINE NUMBERS PXS-PL-L057B) |
| 3941 | SV3-PXS-P0W-ME2944 | ASME Section III - Fabrication/Installation of Isometric # SV3-PXS-PLW-281 (Line Numbers PXS-PL-L057B) |
| 3942 | SV3-PXS-P0W-ME2945 | AMSE Section III - Fabrication/Installation of Isometric # SV3-PXS-PLW-283 (Line Numbers PXS-PL-L149B) |
| 3943 | SV3-PXS-P0W-ME2946 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-284 (LINE NUMBERS PXS-PL-L148B) |
| 3944 | SV3-PXS-P0W-ME2966 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-01H (LINE NUMBERS PXS-PL-L109, L132A) |
| 3945 | SV3-PXS-P0W-ME2968 | ASME SECTION III- FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-01Q (LINE NUMBERS PXS-PL-L021A, L026A, L127A) |
| 3946 | SV3-RCS-P0W-ME2710 | INSTALLATION OF SMALL BORE RCS PIPING (INCLUDES ISOMETRIC: SV3-RCS-PLW-280) |
| 3947 | SV3-RCS-P0W-ME2711 | Installation of Small Bore RCS Piping (Includes Isometric SV3-RCS-PLW-282) |
| 3948 | SV3-RCS-P0W-ME2712 | INSTALLATION OF SMALL BORE RCS PIPING (INCLUDES ISOMETRIC: SV3-RCS-PLW-290) |
| 3949 | SV3-RCS-P0W-ME2713 | Installation of Small Bore RCS Piping (Includes Isometric SV3-RCS-PLW-292) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3950 | SV0-0000-ERW-EL5902 | INSTALLATION OF NEW DUCT BANKS AND DIRECT BURIED TO EXPOSED RACEWAYS AT 315 BLDG FOR SYSTEMS RWS, PWS, YFS AND ZFS |
| 3951 | SV3-RCS-P0W-ME2714 | Installation of Small Bore RCS Piping (Includes Isometric: SV3-RCS-PLW-927, 929) |
| 3952 | SV3-RCS-P0W-ME2715 | INSTALLATION OF SMALL BORE RCS PIPING (INCLUDES ISOMETRIC: SV3-RCS-PLW-928, 92A) |
| 3953 | SV3-RNS-P0W-ME2829 | INSTALLATION OF LARGE BORE RNS PIPING (INCLUDES ISOMETRICS: SV3-RNS-PLW-022,023,07A) |
| 3954 | SV3-RNS-P0W-ME2830 | INSTALLATION OF LARGE BORE RNS PIPING (INCLUDES ISOMETRICS: SV3-RNS-PLW-024) |
| 3955 | SV3-RNS-PLW-ME2704 | INSTALLATION OF RNS LARGE BORE PIPING (INCLUDES ISOMETRIC SV3-RNS-PLW-141) |
| 3956 | SV3-RNS-PLW-ME2705 | INSTALLATION OF RNS LARGE BORE PIPING (INCLUDES ISOMETRIC SV3-RNS-PLW-161) |
| 3957 | SV3-RWS-P0W-ME6785 | FABRICATE AND INSTALL THE RWS SUPPLY TO THE UNIT 3 COOLING TOWER BASINS A & B AND TO THE DTS PRETREATMENT SKID. |
| 3958 | SV3-CVS-P0W-800005 | Install large bore pipe per SV3-CVS-PLW-531 |
| 3959 | SV3-CVS-P0W-800007 | Install small bore pipe and supports per SV3-CVS-PLW-65D |
| 3960 | SV3-FPS-PHW-800001 | Install large bore pipe supports per SV3-FPS-PLW-713 |
| 3961 | SV3-RNS-PHW-800003 | Install large bore pipe supports per SV3-RNS-PLW-094 |
| 3962 | SV3-RNS-P0W-800001 | Install large bore pipe per SV3-RNS-PLW-17F |
| 3963 | SV3-SDS-P0W-ME2139 | FABRICATE AND INSTALL SANITARY DRAIN PIPING UNDER THE UNIT 3 ANNEX SLAB #1 |
| 3964 | SV3-SDS-P0W-ME2300 | FABRICATE AND INSTALL SANITARY DRAIN PIPING UNDER THE UNIT 3 ANNEX SLAB #2 |
| 3965 | SV3-SDS-P0W-ME2302 | FABRICATE AND INSTALL SANITARY DRAIN PIPING UNDER THE UNIT 3 ANNEX SLAB #4 |
| 3966 | SV3-WGS-ITW-ME4483 | FUNCTIONAL ARRANGEMENT WALKDOWN OF WGS SYSTEM. |
| 3967 | SV3-WLS-MTW-ME0745 | WLS EFFLUENT HOLDUP TANK A INSTALLATION |
| 3968 | SV3-WLS-PHW-ME1044 | Fabrication/ Installation of Pipe Supports for Isometric Drawing WLS-PLW-071 |
| 3969 | SV0-869-XVW-CV6004 | NORTH VEHICLE BARRIER DITCH |
| 3970 | SV3-WLS-PLW-ME0936 | Fabricate and Install Small Bore Elevation 1 WLS Piping Iso SV3-WLS-PLW-041 |
| 3971 | SV4-1000-XCW-CV0059 | Place Category 2 Backfill, EGB, and Common Fill in Unit 4 Excavation from Elevation - 180ft to Final Grade |
| 3972 | SV0-SM01-CSW-MU0899 | Mock up for Concrete Placement for the AP1000 Shield Building RS/SC Connection Zone and Air Inlet/Tension Ring |
| 3973 | SV3-0000-CEW-CV2806 | UNIT 3 TURBINE BUILDING TRANSFORMER FOUNDATION EMBED |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3974 | SV3-0000-EGW-EL2316 | Perform Installation of Underground Commodities (SV3-SITE STATION GROUNDING GRID) For Ground Grid Area,K1300 |
| 3975 | SV4-CWS-P0W-ME3242 | INSTALLATION OF CWS PIPING RISERS (SUPPLY SIDE) |
| 3976 | SV3-0500-CFW-CV2605 | INSTALL/REMOVE 2" SHAKE SPACE FORMS |
| 3977 | SV3-1000-CEW-CV0353 | UNIT 3 NUCLEAR ISLAND BASEMAT CAST-IN-PLACE ANCHOR BOLTS |
| 3978 | SV3-1120-ERW-EL3065 | Fabrication and Installation of non-scheduled, Detail C13 conduit supports in Unit 3 Containment Building. Seismic category II. WP1 |
| 3979 | SV3-1134-SSW-CV6173 | SPL43 INSTALLATION |
| 3980 | SV3-1208-CRW-CV5106 | U3 Shield Building Wall Concrete Reinforcement Fabrication and Installation El 100ft-0in to El 117ft-6in |
| 3981 | SV3-1208-CRW-CV5111 | Installation of Reinforcing Steel through Unit 3 Shield Building Panels (01J - 01G, 01Q, 01R) & First Course #14 Nut Installation |
| 3982 | SV3-1210-CCW-CV2549 | CONCRETE PLACEMENT IN N-LINE & CONTAINMENT BLOCKOUT UP TO ELEV 100'-0" |
| 3983 | SV3-1210-EGW-EL1068 | Unit 3 Auxillary Bldg EL.66'-6" Grounding Work Package for Walls 6,7, 8 |
| 3984 | SV3-1210-EGW-EL5393 | Install Grounding To Modules & Stairwells For SV3 Auxiliary Building, Level 66’-6”, Area 1 thru 6 |
| 3985 | SV3-1230-CEW-CV4403 | VOGTLE UNIT 3 AUXILIARY BUILDING AREA 2, EMBEDS AND TEMPORARY FORMWORK, ELEVATION 100 FT. |
| 3986 | SV3-1230-CPW-CV3079 | UNIT 3 AUXILIARY BUILDING PRECAST CONCRETE FLOOR PANELS EL. 92FT.-6IN. |
| 3987 | SV3-2000-Z0W-CV5182 | UNIT 3 TURBINE BUILDING REINFORCED CONCRETE REQUIREMENTS |
| 3988 | SV3-2020-MEW-ME1397 | Unit 3 Condenser A Spring Support Foundation Installation |
| 3989 | SV3-2020-MEW-ME1480 | Unit 3 Condenser C Outlet Box Installation |
| 3990 | SV3-2033-SHW-EL6792 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE TURBINE BUILDING ELEVATION 100'0" AREA 3 FROM COLUMNS 19 TO 20 & L.1 TO R |
| 3991 | SV3-2037-SHW-EL6160 | ELECTRICAL CABLE TRAY SUPPORTS INSTALLATION FOR THE TURBINE BUILDING AT ELEVATION 100'-0" IN AREA 7 |
| 3992 | SV3-2037-SHW-EL6793 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE TURBINE BUILDING FOR ELEV 100'-0" AREA 7 FROM COLUMNS 18 TO 20 AND K.1 TO L.1 |
| 3993 | SV3-2050-EGW-EL3089 | ELECTRICAL GROUNDING INSTALLATION FOR THE TURBINE BUILDING AT ELEVATIONS 135'-3" AND 141'-3" |
| 3994 | SV3-2060-ERW-EL3272 | ELECTRICAL EMBEDDED CONDUIT INSTALLATION FOR THE TURBINE BUILDING CA-81 TURBINE DECK SLAB AT ELEVATION 170'-0" |
| 3995 | SV3-4000-SSW-CV3868 | ANNEX BUILDING AREAS 1-3 STEEL ERECTION GENERAL NOTES, DETAILS AND SPECIFICATIONS |
| 3996 | SV3-4000-Z0W-CV4379 | UNIT 3 ANNEX BUILDING REINFORCED CONCRETE REQUIREMENTS |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 3997 | SV3-4030-CCW-CV5233 | UNIT 3 ANNEX BUILDING MISCELLANEOUS GROUTING AT ELEVATION 100' 0" |
| 3998 | SV3-4030-CCW-CV5234 | UNIT 3 ANNEX BUILDING MISCELLANEOUS GROUTING AT ELEVATION 107'-2" & ABOVE |
| 3999 | SV3-4031-ERW-EL6600 | INSTALLATION OF CONDUIT SLEEVES FOR RACEWAY PENETRATIONS, ANNEX BUILDING, AREA 1, ELEVATION 100'-0" |
| 4000 | SV3-4040-SSW-CV2289 | ANNEX BUILDING STRUCTURAL STEEL AREA 4 SEQUENCE |
| 4001 | SV3-4041-CEW-CV3183 | U3 ANNEX BUILDING AREA 1 EMBEDDED ITEMS FROM ELEVATION 100-'0" TO 117'-6" |
| 4002 | SV3-FPS-PHW-ME2576 | INSTALLATION OF ANNEX FPS PIPING SUPPORTS FOR WP (SV3-FPS-PLW-ME2573) |
| 4003 | SV3-ASS-PHW-ME1527 | FABRICATE/INSTALL OF AUXILIARY STEAM (ASS) SUPPORTS (PORTION 4) FOR ISOMETRIC# SV3-ASS-PLW-020, 022, 02V, 02S, & 02H |
| 4004 | SV3-ASS-PLW-ME1475 | FABRICATE AND INSTALL AUXILIARY STEAM SYSTEM(ASS) PIPING PORTION 3 FOR 82'-9" |
| 4005 | SV3-CA01-MHW-CV2160 | Lifting Frames and Bracing Submodules 01 Thru 03, Thru 24, & 25 |
| 4006 | SV3-CA01-MHW-CV4242 | CA01 INSTALL TEMP BRACES SG1 ROOM (WEST) FOR LIFT |
| 4007 | SV3-CA01-MHW-CV4243 | CA01 REMOVE LIFT LUGS AT SM 04. 11, 12 AND 13 |
| 4008 | SV3-CA01-MHW-CV4244 | CA01 REMOVE LIFT LUGS AT SM 16, 17, 18 AND 19 |
| 4009 | SV3-CA01-S4W-CV2066 | CA01 POST WELDING SURVEY DATA/VERIFICATION |
| 4010 | SV3-CA22-S8W-CV6249 | CA22 Floor Module 82'-6"" |
| 4011 | SV3-CA33-S5W-CV5950 | U3 CONTAINMENT INSTALLATION OF CA33 STIFFENERS, AREA REINFORCING BAR FABRICATION & STAGING |
| 4012 | SV3-CAS-P0W-ME2110 | Fabricate and Install CAS Small Bore Piping shown on Isometric Drawing # SV3-CAS-PLW-732 & SV#-CAS-PLW-733 |
| 4013 | SV3-CAS-P0W-ME2111 | FABRICATE AND INSTALL CAS SMALL BORE PIPING SHOWN ON ISOMETRIC DRAWING# SV3-CAS-PLW-755 & SV3-CAS-PLW-759 |
| 4014 | SV3-CAS-P0W-ME2112 | Fabricate and Install CAS Small Bore Piping shown on Isometric Drawing # SV3-CAS-PLW-764 & SV3-CAS-PLW-77A |
| 4015 | SV3-CAS-P0W-ME2113 | Fabricate and Install CAS Small Bore Piping shown on Isometric Drawing # SV3-CAS-PLW-77B |
| 4016 | SV3-CAS-P0W-ME2119 | FABRICATE AND INSTALL CAS SMALL BORE PIPING SHOWN ON ISOMETRIC DRAWING# SV3-CAS-PLW-853 |
| 4017 | SV3-CAS-P0W-ME3433 | INSTALLATION OF SMALL BORE CAS PIPING (INCLUDES SV3-CAS-PLW-413, 414) |
| 4018 | SV3-CAS-PHW-ME2780 | INSTALLATION OF SMALL BORE CAS PIPING SUPPORTS (INCLUDES ISOMETRIC SV3-CAS-PLW-732) |
| 4019 | SV3-CAS-PHW-ME2786 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-CAS-PLW-835 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 4020 | SV3-CAS-PHW-ME2787 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-CAS-PLW-83F |
| 4021 | SV3-CCS-P0W-ME2822 | Installation of Large Bore CCS Piping (Includes Isometrics: SV3-CCS-PLW-700, 701) |
| 4022 | SV3-CCS-P0W-ME2823 | INSTALLATION OF LARGE BORE CCS PIPING (INCLUDES ISOMETRICS: SV3-CCS-PLW-710, 711) |
| 4023 | SV3-CAS-PHW-ME2789 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-CAS-PLW-853 |
| 4024 | SV3-CAS-PHW-ME2791 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-CAS-PLW-86D |
| 4025 | SV3-CDS-PHW-ME2184 | INSTALLATION OF CDS LARGE BORE PUMP DISCHARGE PIPING SUPPORTS FOR PIPING INCLUDED IN THE SV3-CDS-PLW-ME2183 WORK PACKAGE |
| 4026 | SV3-CAS-THW-ME5582 | HYDROSTATIC TESTING OF THE COMPRESSED & INSTRUMENT AIR PIPING FROM UNIT 3 ANNEX TO UNIT 3 DIESEL GENERATOR BLDG., |
| 4027 | SV3-CDS-PHW-ME2186 | Installation of CDS Large Bore Pump Discharge Piping Supports For Piping Included in The SV3-CDS-PLW-ME2185 Work Package |
| 4028 | SV3-CB00-S5W-CV2690 | UNIT 3, NUCLEAR ISLAND, INSTALL OVERLAY PLATES FOR CB MODULES |
| 4029 | SV3-CDS-PLW-ME2183 | INSTALLATION OF LARGE BORE PUMP DISCHARGE PIPING; SV3-CDS-PLW-70AA, SV3-CDS-PLW-70A, SV3-CDS-PLW-70B, SV3-CDS-PLW-70C, SV3-CDS-PLW-70D, SV3-CDS-PLW-70E |
| 4030 | SV3-CDS-PLW-ME2185 | INSTALLATION OF LARGE BORE PUMP DISCHARGE PIPING; SV3-CDS-PLW-01AM, SV3-CDS-PLW-013 SPOOL #5, SV3-CDS-PLW-014, SV3-CDS-PLW-015 |
| 4031 | SV3-CB00-S8W-CV2681 | INSTALLATION OF CB MODULES 51, 52, 53 & 54 AT ELEVATION 80'0 |
| 4032 | SV3-CDS-PLW-ME2306 | INSTALLATION OF CDS PIPING FOR ISOMETRICS SV3-CDS-PLW-020, SV3-CDS-PLW-021, SV3-CDS-PLW-030, SV3-CDS-PLW-031, SV3-CDS-PLW-040, SV3-CDS-PLW-041. |
| 4033 | SV3-CES-PHW-ME1569 | Fabrication/Installation of Pipe Supports for Isometric Drawing SV3-CES-PLW-702 |
| 4034 | SV3-CB00-S8W-CV4047 | UNIT 3 CONTAINMENT INSTALLATION OF CB MODULE 11 & MODULE 12 AT ELEV 84'-6" |
| 4035 | SV3-CES-PLW-ME1552 | FABRICATE AND INSTALL CONDENSER TUBE CLEANING SYSTEM (CES) PIPING IN TURBINE BUILDING ELEV. 82'-6"-100'-0" (ISO SV3-CES-PLW-701, 702, 710, 741, 742,750) |
| 4036 | SV3-CCS-P0W-ME2455 | INSTALLATION OF SMALL BORE CCS PIPING (INCLUDES ISOMETRIC: SV3-CCS-PLW-113 |
| 4037 | SV3-CCS-P0W-ME2775 | Installation of Large Bore Piping ( Includes Isometrics SV#-CCS-PLW-100, 102) |
| 4038 | SV3-CPS-P0W-ME2121 | FABRICATION AND INSTALLATION OF CPS PIPING FROM EL 100'-0" TO SUMPS SV3-WWS-MT-09A/B |
| 4039 | SV3-CVS-P0W-ME2594 | ASM E Secti on Ill - Fabrication/ Install ati on of Isometric# SV3-CVS-PLW- I l 2 (Line Numbers CVS-PL-L026 & CVS-PL-L540) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 4040 | SV3-CCS-P0W-ME2776 | Installation of Large Bore CCS Piping (Includes Isometrics: SV#-CCS-PLW-110, 112) |
| 4041 | SV3-CVS-P0W-ME2595 | ASME Section III - Fabrication\Installation of Isometric# SV3-CVS-PLW-184 (Line Number CVS-PL-L066 |
| 4042 | SV3-CVS-P0W-ME2596 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC#S SV3-CVS-PLW-762 & SV3-CVS-PLW-763(LINE NUMBER CVS-PL-L066) |
| 4043 | SV3-CCS-P0W-ME2778 | INSTALLATION OF LARGE BORE CCS PIPING (INCLUDES ISOMETRICS: SV3-CCS-PLW-140, 142) |
| 4044 | SV3-CCS-P0W-ME2779 | Installation of Large Bore Piping (Includes Isometrics: SV3-CCS-PLW-150, 152) |
| 4045 | SV3-CWS-PLW-ME0973 | Installation of PCCP Piping for CWS Unit #3 Phase 3 Supply Line |
| 4046 | SV3-CWS-PLW-ME2523 | INSTALLATION OF CWS PIPING FOR ISOMETRICS SV3-CWS-PLW-70AK, SV3-CWS-PLW-70AR, SV3-CWS-PLW-71J, SV3-CWS-PLW-71K |
| 4047 | SV3-CWS-PLW-ME2527 | INSTALLATION OF CWS PIPING FOR ISOMETRICS SV3-CWS-PLW-70AL, SV3-CWS-PLW-70N, SV3-CWS-PLW-71E, SV3-CWS-PLW-71F |
| 4048 | SV3-CVS-P0W-ME2655 | INSTALLATION OF SMALL BORE CVS PIPING (INCLUDES ISOMETRICS: SV3-CVS-PLW-101, 104) |
| 4049 | SV3-CVS-P0W-ME2657 | INSTALLATION OF SMALL BORE CVS PIPING (INCLUDES ISOMETRIC: SV3-CVS-PLW-110) |
| 4050 | SV3-G100-XEW-CV0416 | Unit 3 Nuclear Island Vertical Waterproofing Membrane Completion |
| 4051 | SV3-CVS-P0W-ME2658 | INSTALLATION OF SMALL BORE CVS PIPING (INCLUDES ISOMETRICS: SV3-CVS-PLW-290, 292) |
| 4052 | SV3-CVS-P0W-ME2659 | INSTALLATION OF SMALL BORE CVS PIPING (INCLUDES ISOMETRIC: SV3-CVS-PLW-800) |
| 4053 | SV3-CVS-P0W-ME2660 | INSTALLATION OF SMALL BORE CVS PIPING (INCLUDES ISOMETRIC: SV3-CVS-PLW-801) |
| 4054 | SV3-KB04-KBW-ME0442 | Installation of KB04 Module (WGS Delay and Gaurd Bed) RESERVED FOR Brian Bleakly |
| 4055 | SV3-KB15-KBW-ME0451 | INSTALLATION OF MODULE KB15 (DEGASIFIER DISCHARGE PUMP) |
| 4056 | SV3-ME01-PLW-ME1015 | UNIT 3 CONDENSER A: INSTALLATION OF CASING DRAIN PIPING |
| 4057 | SV3-ME01-PLW-ME1111 | UNIT 3 CONDENSER A: HOTWELL PIPING |
| 4058 | SV3-ML05-MLW-ME2171 | INSTALLATION OF PENETRATIONS IN CA20 WALLS J-1, J-2, K-2 |
| 4059 | SV3-ML05-MLW-ME4411 | INSTALLATION OF CA01 ROOM 11300 PENETRATIONS |
| 4060 | SV3-ML05-MLW-ME4936 | INSTALLATION OF CA01 ASME WALL PENETRATIONS |
| 4061 | SV3-R104-MDW-ME2992 | INSTALLATION OF HVAC ON R104 MODULE |
| 4062 | SV3-VWS-PHW-ME4477 | INSTALL PIPE SUPPORTS FOR WP SV3-VWS-P0W-ME4476 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 4063 | SV3-WLS-PLW-ME0939 | Fabricate and Install Small Bore Elevation 1 WLS Piping Iso SV3-WLS-PLW-061 and 06B |
| 4064 | SV3-WRS-PLW-ME0607 | WRS LARGE BORE PIPING INSTALLATION (INCLUDES ISOMETRIC SV3-WRS-PLW-56D AND 56E) |
| 4065 | SV3-WRS-PLW-ME2483 | WRS EMBEDDED PIPING INSTALLATION (INCLUDING ISOMETRIC SV3-WRS-PLW-522) |
| 4066 | SV3-WRS-PLW-ME4435 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES SV3-WRS-PLW-811, 812, 813, 814, 815, 816, 817, 818, 819) |
| 4067 | SV3-WRS-PLW-ME4447 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES SV3-WRS-PLW-81A, 81B, 81C, 81D) |
| 4068 | SV3-WRS-PLW-ME4450 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES SV3-WRS-PLW-81H, 81K, 81J, 81L, 81M, 81N, 81P, 81Q, 81R, 81S) |
| 4069 | SV3-WRS-PLW-ME4455 | INSTALLATION OF SMALL BORE WRS PIPING (INCLUDES SV3-WRS-PLW-83D) |
| 4070 | SV3-WRS-THW-ME0717 | RADIOACTIVE WASTE DRAIN SYSTEM (WRS) HYDROSTATIC TESTING |
| 4071 | SV3-WRS-THW-ME2831 | ANNEX BUILDING-WRS HYDROSTATIC TESTING |
| 4072 | SV3-WRS-THW-ME4467 | TESTING OF CA20 LEAK CHASE |
| 4073 | SV3-WWS-MTW-ME2587 | INSTALL UNIT 3 TRANSFORMERS SUMP SV3-WWS-MT-010. |
| 4074 | SV3-WWS-MTW-ME2644 | INSTALL UNIT 3 DIESEL FUEL OIL TANK AREA SUMP SV3-WWS-MT-04. |
| 4075 | SV3-WWS-P0W-ME2140 | FABRICATE AND INSTALL THE WASTE WATER PIPING UNDER THE UNIT 3 ANNEX BASEMAT SLAB |
| 4076 | SV0-RWS-PLW-ME1268 | RAW WATER SYSTEM |
| 4077 | SV0-RWS-PLW-ME1269 | INSTALLATION |
| 4078 | SV3-WWS-P0W-ME2194 | FABRICATE AND INSTALL THE WASTE WATER PIPING FOR THE UNIT 3 OIL/WATER SEPARATOR. |
| 4079 | SV0-RWS-THW-ME4321 | HYDRO TEST OF THE HDPE PIPING FOR UNIT 3 AND UNIT 4 RAW WATER SYSTEM (RWS) |
| 4080 | SV0-ZRS-EWW-TP0671 | Relocation of Power loop between Switchgears #4 and #5 Involving Transformers #11, #12 and #13 |
| 4081 | SV3-WWS-P0W-ME2280 | ANNEX BUILDING - EMBEDDED WWS PIPING PACKAGE #2 |
| 4082 | SV3-PXS-P0W-ME2947 | ASME SECTION III- FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-285 (LINE NUMBERS PXS-PL-L148A) |
| 4083 | SV3-SFS-P0W-ME3649 | INSTALLATION OF LARGE BORE SFS PIPING (INCLUDES ISOMETRIC SV3-SFS-PLW-565) |
| 4084 | SV4-CVS-THW-862254 | CVS PRESSURE TEST |
| 4085 | SV3-1130-C0W-850005 | CONTAINMENT CONCRETE PLACEMENT, NORTH AND EAST SIDE TO ELEV 105'-2" |
| 4086 | SV4-CAS-P0W-800015 | Repair Pipe ISO SV4-CAS-PLW-420 per SV4-CAS-GNR-000003 and Install Small Bore Piping per Isometric SV4-CAS-PLW-42C |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 4087 | SV3-2045-SHW-860225 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEV 120'-6", AREA 5, COLUMNS 14 TO 16 & BETWEEN K.1 TO I2 |
| 4088 | SV3-1208-C0W-850008 | SHIELD BUILDING 117'-6" CYLINDRICAL WALL RC08C |
| 4089 | SV3-4000-SHW-862385 | FABRICATION AND INSTALLATION OF TYPICAL FIELD ROUTED CONDUIT SUPPORTS DETAIL C-83A ANNEX BUILDING ALL AREAS/ELEVATIONS BOOK 1 |
| 4090 | SV3-4052-ERW-862398 | INSTALLATION OF CONDUIT PENETRATION SLEEVES, ANNEX BUILDING AREA 2 ELEV 135'-3" AND ABOVE |
| 4091 | SV3-ML05-MLW-862934 | INSTALLATION OF 92'-6' FLOOR PIPING PENETRATIONS |
| 4092 | SV3-CNS-MLW-861727 | ASME SECTION III – FABRICATION/INSTALLATION OF ELECTRICAL CONTAINMENT VESSEL PENETRATIONS SV3-CNS-ML-E14, -E15, -E16, -E27, -E28, -E29, -E30, -E31, -E32 |
| 4093 | SV3-CDS-P0W-ME3711 | INSTALLATION OF CDS PIPING ISOMETRICS ON 100' ELEVATION. |
| 4094 | SV4-2060-ERW-862154 | EMBEDDED CONDUIT INSTALLATION IN THE UNIT 4 TURBINE DECK SLAB AT ELEVATION 170'-0" |
| 4095 | SV3-2038-SHW-863053 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE UNIT 3 TURBINE BUILDING, AREA 8, ELEVATION 100' , COLUMNS 13.05 TO 13.1 & H.05 TO I.2 |
| 4096 | SV4-MS08-MSW-ME7106 | INSTALLATION OF CORS DEMINERALIZED WATER FEED PUMP(DWS-MP-02) |
| 4097 | SV3-CCS-P0W-ME4094 | INSTALLATION OF SMALL BORE CCS PIPING INCLUDING ISOMETRICS SV3-CCS-PLW-382 , -392 |
| 4098 | SV3-MS21-MEW-ME3688 | INSTALLATION OF SSS CONDENSER HOTWELL PUMPS (SSS-MS-01A/B/C) |
| 4099 | SV3-4041-SHW-862628 | ELECTRICAL CABLE TRAY TRAPEZE SUPPORTS FABRICATION AND INSTALLATION IN THE UNIT 3 ANNEX BUILDING, ELEVATION 117'-6" AND 126'-3", AREA 1 |
| 4100 | SV3-4041-SHW-862621 | ELECTRICAL CABLE TRAY TRAPEZE SUPPORTS FABRICATION AND INSTALLATION IN THE UNIT 3 ANNEX BUILDING, ELEVATION 117'-6" AND 126'-3", AREA 1 |
| 4101 | SV3-4041-SHW-862631 | ELECTRICAL CABLE TRAY TRAPEZE SUPPORTS FABRICATION AND INSTALLATION IN THE UNIT 3 ANNEX BUILDING, ELEVATION 117'-6" AND 126'-3", AREA 1 |
| 4102 | SV3-4041-SHW-862618 | ELECTRICAL CABLE TRAY TRAPEZE SUPPORTS FABRICATION AND INSTALLATION IN THE UNIT 3 ANNEX BUILDING, ELEVATION 117'-6" AND 126'-3", AREA 1 |
| 4103 | SV3-4041-SHW-862627 | ELECTRICAL CABLE TRAY WELDED SUPPORTS FABRICATION AND INSTALLATION IN THE UNIT 3 ANNEX BUILDING, ELEVATION 117'-6" AND 126'-3", AREA 1 |
| 4104 | SV4-WLS-PHW-861544 | INSTALLATION OF PIPE SUPPORTS FOR SV4-WLS-PLW-319 |
| 4105 | SV3-2053-SHW-800001 | Electrical Cable Tray Support Fab and Installation in Unit 3 Turbine Building, Elevation 141’ 3”, Area 3 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 4106 | SV3-2058-SHW-861427 | ELECTRICAL CABLE TRAY WELDED SUPPORT INSTALLATION IN THE TURBINE BUILDING, ELEVATION 141¿3¿ , AREA 8, ROOM 20500 PART 4 |
| 4107 | SV3-2055-SHW-862715 | Fabrication/Installation of Electrical Cable Tray Supports - Unit 3 Turbine Building, Elevation 141'-3", Area 5 |
| 4108 | SV3-2055-SHW-862716 | Fabrication/Installation of Trapeze Supports Unit 3 Turbine Building, Elevation 141'3" |
| 4109 | SV4-SFS-P0W-861660 | Installation of Pipiing for SV4-SFS-PLW-390 |
| 4110 | SV3-2051-ECW-862112 | INTALLATION OF 480VAC MCC (ECS-EC-122) IN THE UNIT 3 TURBINE BUILDING, ELEVATION 141'3", AREA 1 |
| 4111 | SV3-CNS-MLW-861728 | ASME SECTION III-FABRICATION/INSTALLATION OF ELECTRICAQL CONTAINMENT VESSEL PENETRATIONS SV3-CNS-ML-E17,-E18,-E19,-E20,-E21,-E22,-E23,-E24,-E25,-E26 |
| 4112 | SV4-CA20-S4W-862963 | INSTALLATION OF VAS-MS-06A SUPPORT STEEL |
| 4113 | SV3-2070-SSW-CV8965 | Turbine Building Roof Decking, Sequence 14, 15 and 16 |
| 4114 | SV3-1221-SHW-861929 | CABLE TRAY SUPPORTS RM 12211 |
| 4115 | SV3-KB11-KBW-863010 | COMPLETE KB11 MODULE FABRICATION POST MODULE INSTALLATION |
| 4116 | SV4-CA20-S4W-862964 | INSTALLATION OF VAS-MS-06B SUPPORT STEEL |
| 4117 | SV3-KB12-KBW-863011 | COMPLETE KB12 MODULE FABRICATION POST MODULE INSTALLATION |
| 4118 | SV3-2038-ERW-862059 | INSTALLATION OF ELECTRICAL CABLE TRAY RACEWAY IN THE UNIT 3 TURBINE BUILDING, ELEVATION 100'0" , AREA 8 |
| 4119 | SV3-2038-ERW-862054 | INSTALLATION OF ELECTRICAL CABLE TRAY RACEWAY IN THE UNIT 3 TURBINE BUILDING, ELEVATION 100' 0", AREA 8 |
| 4120 | SV3-2038-ERW-862055 | INSTALLATION OF ELECTRICAL CABLE TRAY RACEWAY IN THE UNIT 3 TURBINE BUILDING, ELEVATION 100' 0" , AREA 8 |
| 4121 | SV3-2038-ERW-862053 | INSTALLATION OF ELECTRICAL CABLE TRAY RACEWAY IN THE UNIT 3 TURBINE BUILDING, ELEVATION 100' 0", AREA 8 |
| 4122 | SV3-EDS1-DBW-861176 | INSTALLATION OF BATTERIES AND ASSOCIATED HARDWARE FOR "EDS1" 125V NON-CLASS 1E, DC &UPS SYSTEM (GROUP I) IN ANNEX BLDG. ROOM 40307 |
| 4123 | SV3-2033-ETW-861901 | INSTALLATION OF 30KVA TRANSFORMER (ECS-ET-3141) IN THE UNIT 3 TURBINE BUILDING, ELEVATION 100' 0", AREA 3 |
| 4124 | SV4-WWS-P0W-ME6282 | WWS PIPING TO THE UNIT 4 WASTE WATER RETENTION BASIN |
| 4125 | SV3-PGS-PHW-862909 | INSTALLATION OF PGS PIPE SUPPORTS IN ANNEX 3 |
| 4126 | SV4-FPS-P0W-860892 | INSTALLATION AND FABRICATION OF FIRE PROTECTION SYSTEMS(FPS) PIPING |
| 4127 | SV4-WLS-PHW-861961 | FABRICATION/INSTALLATION OF WLS PIPING SUPPORTS SHOWN ON ISOMETRIC DRAWING SV4-WLS-PLW-380 |
| 4128 | SV4-WRS-PHW-861957 | FABRICATION/INSTALLATION OF WRS PIPING SUPPORTS SHOWN ON ISOMETRIC DRAWINGS SV4-WRS-PLW-59W & -593 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 4129 | SV3-FPS-PHW-854232 | INSTALL SUPPORTS FOR DRAWINGS SV3-FPS-PLW-55L, -55N, 555 |
| 4130 | SV4-CA03-S5W-863063 | CA03 UNSATISFACTORY IRS/N&DS/E&DCRS AND MISCELLANEOUS WORK |
| 4131 | SV3-CA32-CAW-850001 | Unit 3, CA32 Module Installation |
| 4132 | SV3-2053-SHW-800002 | Electrical Cable Tray Trapeze Support Fab and Installation in Unit 3 Turbine Building, Elevation 141’ 3”, Area 3 |
| 4133 | SV0-YFS-PLW-ME0134 | INSTALLATION OF THE YARD FIRE SYSTEM PIPING IN TRENCH 6. |
| 4134 | SV4-2053-SHW-862447 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE TURBINE BUILDING, ELEVATION 141'-3", AREA 3 FROM COLUMNS 18 TO 19 & P.2 TO R |
| 4135 | SV3-RNS-PHW-861885 | FABRICATION/INSTALLATION OF B31.1 PIPE SUPPORTS FOR ISOMETRIC SV3-RNS-PLW-024 |
| 4136 | SV3-SFS-PHW-800002 | Install Large Bore Pipe Supports Per SV3-SFS-PLW-538 |
| 4137 | SV3-CVS-PHW-800006 | Install Small Bore Pipe Supports Per SV3-CVS-PLW-65A |
| 4138 | SV4-CCS-PHW-862867 | INSTALLATION OF CCS PIPE SUPPORTS IN ANNEX 4 |
| 4139 | SV4-WLS-P0W-861364 | INSTALLATION OF PIPING FOR ISOMETRICS SV4-WLS-PLW-33B, -33G, -33H & -33K |
| 4140 | SV4-1231-CDW-800000 | 100' Elev., Decking & Grating, Areas 1 |
| 4141 | SV4-PH01-CEW-800001 | Unit 4, Reactor Cavity Anchor Bolts & Anchor Bolt Construction Aid Installation |
| 4142 | SV3-2056-SHW-800004 | Elect Cable Tray Welded Support Fab & Install in Unit 3 Turbine Building, Elevation 141’ 3”, Area 6 |
| 4143 | SV4-MS19-MSW-ME7104 | INSTALLATION OF CONDENSATE POLISHER VESSELS(MS01A/01B), SPENT RESIN TANKS(MS03) AND RESIN HOOPER(MT01) |
| 4144 | SV4-WLS-P0W-861958 | fabrication installation of WLS piping shown on Isometric Drawings SV4-WLS-PLW-14E, -150, -206, -370 and -375 |
| 4145 | SV3-1123-SSW-CV6258 | SPL21 INSTALLATION |
| 4146 | SV3-RNS-PHW-861883 | FABRICATION/INSTALLATION OF B31.1 PIPE SUPPORTS FOR ISOMETRIC SV3-RNS-PLW-021 |
| 4147 | SV3-WLS-P0W-861906 | INSTALL ELECTRO-FUSION COUPLINGS ON UNIT 3 WLS LINE, ISOMETRICS SV3-WLS-PLW-80EK, 80EL, 80EM, 80EN, 80EP, 80EQ, 80ER, 80ES, & 80KC |
| 4148 | SV3-2033-ERW-862335 | ELECTRICAL CABLE TRAY RACEWAY FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEV 100'-0" AREA 3 |
| 4149 | SV3-SGS-MLW-861039 | ASME SECTION III - INSTALLATION OF CONTAINMENT VESSEL PENETRATION SV3-SGS-PY-C02A (P25) |
| 4150 | SV3-SGS-MLW-861040 | ASME SECTION III - INSTALLATION OF CONTAINMENT VESSEL PENETRATION SV3-SGS-PY-C02B (P26) |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 4151 | SV4-WLS-THW-861977 | PNEUMATIC TEST OF THE HDPE PORTION OF UNIT 4 WLS SYSTEM UNDER AND SOUTH OF THE VEHICLE BARRIER DITCH |
| 4152 | SV3-2048-SHW-860226 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE UNIT 3 TURBINE BUILDING AREAS 5 & 8 EL 120'-6" COLMNS 13.1-14 AND H.05-K.1 |
| 4153 | SV3-TDS-P0W-860844 | INSTALLATION AND FABRICATION OF TURBINE ISLAND DRAINS VENTS AND RELIEF SYSTEM (TDS) PIPING |
| 4154 | SV3-4041-SHW-862630 | ELECTRICAL CABLE TRAY TRAPEZE SUPPORTS FABRICATION AND INSTALLATION IN THE UNIT 3 ANNEX BUILDING ELEV 117'-6" AND 126'-3" AREA 1 |
| 4155 | SV3-HDS-P0W-860767 | TI3 HDS PIPING INSTALLATION ISOs SV3-HDS-PLW-091, 092, 093, 094, 095, 096, 097, 111, 112 113, 114, 115 & 116 |
| 4156 | SV3-LOS-PHW-860568 | TURBINE GENERATOR LUBE OIL SYSTEM PIPING SUPPORT INSTALLATION |
| 4157 | SV3-TDS-PHW-860620 | INSTALLATION AND FABRICATION OF TURBINE ISLAND VENTS AND DRAINS AND RELIEF SYSTEMS (TDS) PIPING SUPPORTS |
| 4158 | SV3-TDS-PHW-860616 | INSTALLATION AND FABRICATION OF TURBINE ISLAND VENTS AND DRAINS AND RELIEF SYSTEMS (TDS) PIPING SUPPORTS |
| 4159 | SV3-4041-SHW-862633 | ELECTRICAL CABLE TRAY TRAPEZE SUPPORTS FABRICATION AND INSTALLATION IN THE UNIT 3 ANNEX BUILDING ELEV 117'-6" & 126'3" AREA 1 |
| 4160 | SV3-4041-SHW-862629 | ELECTRICAL CABLE TRAY TRAPEZE SUPPORTS FABRICATION AND INSTALLATION IN THE UNIT 3 ANNEX BUILDING ELEV 117'-6" & 126'3" AREA 1 |
| 4161 | SV4-WLS-THW-862960 | HYDROTEST FOR WLS-PLW-74A,741,750,731 |
| 4162 | SV3-CVS-THW-862237 | CVS PRESSURE TEST |
| 4163 | SV3-DWS-THW-862239 | DWS PRESSURE TEST |
| 4164 | SV4-WLS-P0W-861913 | INSTALL ELECTRO-FUSION COUPLINGS ON UNIT 4 WLS LINE. ISOMETRICS SV4-WLS-PLW-81EV -81EW, -81EX, -81EY, -81EZ, -81FA, -81FB, -81FC & -81KD |
| 4165 | SV3-PXS-PHW-800000 | Install Small Bore Pipe Supports Per SV3-PXS-PLW-299 |
| 4166 | SV4-FPS-P0W-ME7088 | INSTALLATION OF LARGE BORE FPS PIPING INCLUDES ISOMETRICS: SV4-FPS-PLW-821, 827, 829, 82A |
| 4167 | SV4-WWS-PHW-800005 | TB- INSTALL WWS PIPE SUPPORTS ELEV. 100'-0" |
| 4168 | SV4-WWS-PHW-800007 | TB- INSTALL WWS PIPE SUPPORTS ELEV. 170'-0" |
| 4169 | SV4-MS05-MEW-861749 | INSTALLATION OF CAS INSTRUMENT AIR COMPRESSOR - CAS - MS - 01A/B |
| 4170 | SV3-RNS-PHW-861884 | FABRICATION/ INSTALLATION OF B31.1 PIPE SUPPORTS FOR ISOMETRIC SV3-RNS-PLW-022 |
| 4171 | SV3-1237-SHW-860295 | INSTALL CONDUIT SUPPORTS ON SHIELD WALL AZ-90¿ TO AZ-180¿ 100'-0" |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 4172 | SV3-FPS-PHW-854242 | INSTALL LARGE BORE PIPE SUPPORTS FOR SV3-FPS-PLW-55R & -55K |
| 4173 | SV3-FPS-PHW-854201 | LARGE BORE SUPPORTS ISOS SV3-FPS-PLW-55A, 55B & 55C |
| 4174 | SV3-DWS-PHW-800000 | Install Small Bore Supports per Isometric SV3-DWS-PLW-62B |
| 4175 | SV3-CAS-THW-863085 | PNEUMATIC TEST FOR CAS PIPING ON MODULE R219 |
| 4176 | SV3-SFS-THW-863089 | HYDRO TESTING OF SFS PIPING ON MODULE R219 |
| 4177 | SV4-2035-SHW-863007 | UNIT 4 TURBINE BUILDING CABLE TRAY SUPPLEMENTARY STEEL IN AREA 5 ON ELEVATION 100'-0" |
| 4178 | SV4-CA35-S5W-863043 | CA35 SHIP LOOSE ITEM INSTALLATION AND FABRICATION |
| 4179 | SV3-FPS-P0W-854210 | INSTALL LB CONTAINMENT UPPER RING HEADER PIPING PER ISO'S SV3-FPS-PLW-55D, 55V, 55E, 55F, 55W, 55G, 55H, 55I, 55J |
| 4180 | SV3-R261-R2W-863051 | COMPLETE MODULE R261 FABRICATION |
| 4181 | SV3-CA35-CAW-850001 | Unit 3, Module CA35 Installation |
| 4182 | SV4-CA36-S5W-862998 | CA36 SHIP LOOSE ITEM INSTALL |
| 4183 | SV3-CFS-PLW-507-FP715 | FABRICATE SPOOLS SV3-CFS-PLW-507-1, -2 & SV3-CFS-PLW-536-1, -2, & -3 |
| 4184 | SV3-CA20-C0W-850009 | U3 CA20 FLOOR SUBMODULES 43 AND 44 CONCRETE PLACEMENT ELEV 90'-3" |
| 4185 | SV3-CAS-PHW-800002 | Install Small Bore Pipe Supports Per SV3-CAS-PLW-734 |
| 4186 | SV3-2057-SHW-861354 | Electrical Cable Tray Welded Supports |
| 4187 | SV4-2070-SUW-863147 | UNIT 4 TURBINE BUILDING STRUCTURAL STEEL FRAMING SEQUENCE 15 |
| 4188 | SV3-2057-SHW-861377 | Electrical Cable Tray Welded Supports in Turbine Bldg., EL. 141'3", Area 7 |
| 4189 | SV4-CA55-S5W-863080 | UNIT 4 CA55 FABRICATION |
| 4190 | SV3-2057-SHW-861982 | ELECTRICAL CABLE TRAY TRAPEZE SUPPORTS FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 141'-3", AREA 7 |
| 4191 | SV4-DWS-PLW-01D-FP437 | MODIFY PIPE SPOOL SV4-DWS-PLW-01D-1, -2, -4, -5 & -6 |
| 4192 | SV3-1150-EWW-862085 | FABRICATION AND INSTALLATION OF HYDROGEN SENSOR CABLE SUPPORTS AT EL. 135'-3" ON THE CV IN AREAS 1, 2, 3 & 4. |
| 4193 | SV3-1150-ERW-862087 | FABRICATION AND INSTALLATION OF HYDROGEN IGNITER CONDUIT SUPPORTS AT EL 135'-3" IN AREA 2 ON THE CV. |
| 4194 | SV3-1150-ERW-862088 | FABRICATION AND INSTALLATION OF HYDROGEN IGNITER CONDUIT SUPPORTS AT EL 135'-3" IN AREA 3 ON THE CV |
| 4195 | SV3-1150-ERW-862090 | FABRICATION AND INSTALLATION OF HYDROGEN IGNITER CONDUIT SUPPORTS AT EL 135'-3" IN AREA 4 ON THE CV |
| 4196 | SV4-1212-ERW-861218 | INSTALL DESIGN ROUTED CONDUIT AND CONDUIT SUPPORTS IN BATTERY ROOM "A", ROOM 12101 EL. 66¿-6¿ |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 4197 | SV3-CFS-PLW-510-FP719 | FABRICATE SPOOLS SV3-CFS-PLW-510-1, -2, -3 & -4 AND SV3-CFS-PLW-538-1, -2, -3, -4, -5 & -6 |
| 4198 | SV3-CFS-PLW-508-FP717 | FABRICATE SPOOLS SV3-CFS-PLW-508-1, -2 & -3 AND SV3-CFS-PLW-537-1, -2 & -3 |
| 4199 | SV3-WLS-PLW-80BU-FP906 | HYDROSTATIC TEST THE FABRICATED SPOOLS SV3-WLS-PLW-80BU-1A/1B/2 |
| 4200 | SV3-WLS-PLW-80AQ-FP902 | HYDROSTATIC TEST THE FABRICATED SPOOLS SV3-WLS-PLW-80AQ-1/2A/2B |
| 4201 | SV4-1208-C0W-800009 | UNIT 4, SHIELD BLDG, COURSE 3 CONCRETE PLACEMENT |
| 4202 | SV3-1214-ERW-863176 | AUXILARY BUILDING UNIT 3, EL 66'-6", AREA 4, FABRICATE AND INSTALL DESIGNED TRAY SUPPORTS |
| 4203 | SV3-1150-ERW-862091 | FABRICATION AND INSTALLATION OF HYDROGEN IGNITER SUPPORTS AT EL 135'-3" IN AREAS 1, 2, 3 & 4 ON THE CV. |
| 4204 | SV3-WWS-PHW-800000 | Install Large Bore Pipe Supports Per SV3-WWS-PLW-325 |
| 4205 | SV4-1130-SLW-800000 | Upender Pit Installation |
| 4206 | SV3-2037-ERW-862162 | INSTALLATION OF ELECTRICAL CABLE TRAY RACEWAY IN THE UNIT 3 TURBINE BUILDING EL 100'-0" AREA 7 |
| 4207 | SV3-R261-R2W-862915 | INSTALLATION OF MODULE R261 |
| 4208 | SV3-CAS-PHW-800004 | Install Small Bore Pipe Supports Per SV3-CAS-PLW-83B |
| 4209 | SV3-CA37-CAW-850001 | UNIT 3, CA37 MODULE INSTALLATION |
| 4210 | SV3-LOS-P0W-860787 | FABRICATION AND INSTALLATION OF LOS PIPING |
| 4211 | SV3-4002-SSW-863177 | UNIT 3 ANNEX BUILDING, S05 & S06 STAIRS |
| 4212 | SV3-CA33-CAW-850001 | UNIT 3, CA33 MODULE INSTALLATION |
| 4213 | SV3-CA20-S4W-CV2109 | INTERIOR TEMPORARY ATTACHMENTS FOR SUB-ASSEMBLY 4 |
| 4214 | SV4-1231-SAW-850000 | UNIT 4, AUXILIARY BUILDING STUDS FOR 100' ELEV, AREA 1 |
| 4215 | SV3-1240-CRW-800000 | Wall 11 Critical Section, Rebar Fabrication and Installation |
| 4216 | SV3-CAS-PHW-800021 | Install Small Bore Pipe Supports Per SV3-CAS-PLW-862 |
| 4217 | SV3-CCS-PHW-800004 | Install Large Bore Pipe Supports Per SV3-CCS-PLW-04E |
| 4218 | SV3-CCS-PHW-800006 | Install Large Bore Pipe Supports Per SV3-CCS-PLW-05C |
| 4219 | SV3-CCS-PHW-800014 | Install Small Bore Pipe Supports Per SV3-CCS-PLW-05Q |
| 4220 | SV3-CCS-PHW-800016 | Install Small Bore Pipe Supports Per SV3-CCS-PLW-05S |
| 4221 | SV3-CCS-PHW-800026 | Install Small Bore Pipe Supports Per SV3-CCS-PLW-106 |
| 4222 | SV3-CCS-PHW-800027 | Install Small Bore Pipe Supports Per SV3-CCS-PLW-107 |
| 4223 | SV3-CVS-PHW-800009 | Install Large Bore Pipe Supports Per SV3-CVS-PLW-094 |
| 4224 | SV3-CVS-PHW-800014 | Install Small Bore Pipe Supports Per SV3-CVS-PLW-281 |
| 4225 | SV3-DWS-PHW-800006 | Install Small Bore Pipe Supports Per SV3-DWS-PLW-731 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 4226 | SV3-PXS-P0W-ME2888 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC # SV3-PXS-PLW-014 (LINE NUMBERS PXS-PL-L025A, -027A, -L029A) |
| 4227 | SV3-2041-SHW-863124 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE UNIT 3 TURBINE BUILDING, AREA 1, ELEVATION 120'-6", COLUMNS 13.1 TO 16.1 & P.1 TO R |
| 4228 | SV3-2040-SHW-863123 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE UNIT 3 TURBINE BUILDING, AREA 0, ELEVATION 120'-6", COLUMNS 12.1 TO 13.1 & L.1 TO P.2 |
| 4229 | SV4-2036-SHW-863232 | " ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE TURBINE BUILDING, ELEVATION 100'-0". |
| 4230 | SV4-FWS-PHW-860900 | INSTALLATION OF MAIN AND STARTUP FEEDWATER SYSTEM (FWS) PIPE SUPPORTS |
| 4231 | SV4-1234-CPW-850000 | 92'6" TO 100' ELKEV. PRE-CAST PANEL FAB, AUX BLDG. AREA 4 |
| 4232 | SV4-1130-C0W-850001 | UNIT 4, REINFORCED CONCRETE INSIDE CONTAINMENT BLDG. EL. 87'-6" TO 96'-0" EAST SIDE |
| 4233 | SV4-CA20-S4W-850006 | CA20, ROOM 12363, SUBMODULE 75 INSTALLATION |
| 4234 | SV4-HDS-PHW-860902 | FABRICATION AND INSTALLATION OF SV4 HDS PIPING SUPPORTS |
| 4235 | SV4-1231-CPW-850000 | UNIT 4, AUXILLIARY BUILD, AREA 1, 100' ELE. PRECAST PANEL FABRICATION |
| 4236 | SV3-FPS-PHW-800025 | Install Large Bore Pipe Supports Per SV3-FPS-PLW-53B |
| 4237 | SV4-WLS-P0W-861915 | INSTALL ELECTRO-FUSION COUPLINGS ON UNIT 4 WLS LINE. ISOMETRICS SV4-WLS-PLW-81FL, -81FM, -81FP, -81FQ, -81FR, -81FS, -81FT, -81FU, -81FV & -81KF |
| 4238 | SV3-WLS-P0W-861907 | INSTALL ELECTRO-FUSION COUPLINGS ON UNIT 3 WLS LINE. ISOMETRICS SV3-WLS-PLW-80ET, -80EU, -80EV, -80EW, -80EX, -80EY, -80EZ & -80KD |
| 4239 | SV4-WLS-P0W-861914 | INSTALL ELECTRO-FUSION COUPLINGS ON UNIT 4 WLS LINE. ISOMETRICS SV4-WLS-PLW-81FD, -81FE, -81FF, -81FG, -81FH, -81FJ, -81FK & -81KE |
| 4240 | SV3-WLS-P0W-861908 | INSTALL ELECTRO-FUSION COUPLINGS ON UNIT 3 WLS LINE. ISOMETRICS SV3-WLS-PLW-80FA, -80FB, -80FC, -80FD, -80FE, -80FF, -80FG, -80FH, -80FJ & -80KE |
| 4241 | SV3-WWS-P0W-862360 | INSTALLATION OF SMALL BORE WWS PIPING ISOMETRICS SV3-WWS-PLW-036 |
| 4242 | SV3-CA55-S5W-862414 | CA55 FABRICATION |
| 4243 | SV4-4042-SAW-850004 | SUPPLEMENTARY STEEL, EL. 117'-6" , AREA 2 CL H/E & 7.8/9 |
| 4244 | SV3-1244-CPW-800001 | 107'-2" Elev., Precast Panel Fabrication, Area 4 |
| 4245 | SV4-RCS-P0W-800000 | Install small bore pipe and supports per SV4-RCS-PLW-927 |
| 4246 | SV4-RCS-P0W-800005 | Install Small Bore Pipe And Supports Per SV4-RCS-PLW-290 |
| 4247 | SV4-PXS-P0W-800042 | Install Small Bore Pipe And Supports Per SV4-PXS-PLW-652 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 4248 | SV3-RNS-P0W-860286 | FABRICATION / INSTALLATION OF RNS LARGE BORE ISOMETRIC SV3-RNS-PLW-094 |
| 4249 | SV4-4033-ERW-862036 | INSTALLTION OF CONDUIT PENETRATION SLEEVES, ANNEX BUILDING, AREA 3 ELEV 100'-0", 107'-2", 121'-0", & 126'-3" |
| 4250 | SV3-WWS-PHW-862954 | FABRICATION AND INSTALLATION OF WWS PIPING SUPPORTS |
| 4251 | SV3-WWS-PHW-860660 | FABRICATION AND INSTALLATION OF WWS PIPING SUPPORTS |
| 4252 | SV3-2070-C0W-850007 | UNIT 3 TURBINE BUILDING STUDS, REINFORCING STEEL AND CONCRETE PLACEMENT FOR ROOF SLABS OVER NW AND SW STAIRWELLS |
| 4253 | SV3-1232-ERW-861085 | Install Electrical Penetration Sleeves in Interior & Exterior Walls Elevation 100'-0" to 117'-6", Area 2, Unit 3 |
| 4254 | SV0-0000-C0W-862945 | Building 315: Miscellaneous Concrete |
| 4255 | SV4-CA34-S5W-863024 | CA34 MODULE FABRICATION/ASSEMBLY OF LOOSE PARTS |
| 4256 | SV3-1212-ERW-EL3165 | AUXILARY BUILDING UNIT 3, EL 66'-6", AREA 2, FABRICATE AND INSTALL TYPICAL CONDUIT SUPPORTS. |
| 4257 | SV4-MS01-MSW-862269 | INSTALLTION FOR VWS CHILLERS - VWS-MS-01A/B |
| 4258 | SV4-CA57-S5W-863076 | CA57 FABRICATION |
| 4259 | SV4-CA56-S5W-863062 | CA56 MODULE FABRICATION |
| 4260 | SV3-1150-EJW-862092 | FABRICATION AND INSTALLATION OF HYDROGEN SNESOR CONDUIT/ JUNCTION BOX SUPPORTS ON CV RING 3 AND DOME |
| 4261 | SV3-1150-ERW-862089 | FABRICATION AND INSTALLATION OF HYDROGEN SENSOR CONDUIT SPPORTS ON CV RING 3 |
| 4262 | SV4-1220-CEW-800001 | Unit 4 Aux Bldg, Areas 5 & 6, Rooms 12271 to 12275, 82'-6" Elev., Pre-Placement Embedment Plates |
| 4263 | SV4-FPS-P0W-862841 | Installation of FPS Piping in Annex 4 |
| 4264 | SV3-VWS-PHW-862931 | Fabrication and Installation of VWS Piping Supports |
| 4265 | SV3-0150-ERW-861870 | Cable Tray Support for Aux Transformer 2A |
| 4266 | SV4-CA33-CAW-800000 | CA33 Module Installation |
| 4267 | SV4-CA01-S4W-800002 | CA01-44 Submodule Installation |
| 4268 | SV3-DWS-THW-863097 | HYDRO TESTING OF DWS PIPING ON MODULE R261 |
| 4269 | SV3-CCS-THW-863096 | HYDRO TESTING OF CCS PIPING ON MODULE R261 |
| 4270 | SV3-RNS-P0W-800007 | Install Large Bore Piping per Isometric SV3-RNS-PLW-016 |
| 4271 | SV3-FPS-PHW-854202 | INSTALL SUPPORTS FOR DRAWINGS SV3-FPS-PLW-55U AND SV3-FPS-PLW-559 |
| 4272 | SV3-FPS-THW-863098 | HYDRO TESTING OF FPS PIPPING ON MODULE R261 |
| 4273 | SV3-1121-SPW-850012 | SPL 12 Main Support Beam Installation, Unit 3 |

# Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 4274 | SV3-RNS-PHW-851017 | INSTALL LARGE BORE SUPPORTS FROM ISOMETRIC SV3-RNS-PLW-17B |
| 4275 | SV4-VCS-PHW-851020 | INSTALLATION OF SUPPORT VCS-PH-11R0829 |
| 4276 | SV0-PWS-PLW-ME0033 | HDPE Potable Water System Underground Piping for Trench 6 |
| 4277 | SV3-CS17-CSW-800001 | CS17 Module Installation |
| 4278 | SV4-4030-C0W-850005 | 100' Elev. Walls, Pour # 5 |
| 4279 | SV4-VWS-THW-861273 | HYDROSTATIC TESTING OF VWS PIPING ON MODULE R151 |
| 4280 | SV3-2070-C0W-863140 | UNIT 3 TURBINE BUILDING ROOF EXHAUST FAN CURBS |
| 4281 | SV4-PGS-THW-ME2869 | HYDRO TEST THE UNIT 4 PLANT GAS SYSTEM SOUTH OF THE TURBINE BUILDING |
| 4282 | SV4-PGS-THW-ME2870 | HYDRO TEST THE UNIT 4 HIGH PRESSURE NITROGEN PLANT GAS SYSTEM SOUTH OF THE TURBINE BUILDING |
| 4283 | SV4-PGS-P0W-ME2877 | FABRICATE AND INSTALL PGS SMALL BORE CARBON DIOXIDE PIPING SHOWN ON ISOMETRIC DRAWING# SV4-PGS-PLW-898, 899, 900, 901, 902, AND 945 |
| 4284 | SV4-PGS-P0W-ME2875 | FABRICATE AND INSTALL PGS SMALL BORE LP NITROGEN PIPING SHOWN ON ISOMETRIC DRAWING # SV4-PGS-PLW-846, 847, 848, 849, 850 AND 951 |
| 4285 | SV3-1244-SSW-850000 | Auxiliary Building Structural Steel from Elev. 100'-0" to 117'-6", Area 4 |
| 4286 | RFD-SV3-CAS-PHW-850041 | INSTALLATION/FABRICATION OF SMALL BORE PIPE SUPPORTS FOR ISO'S CAS-PLW-41C, 41F, 41G |
| 4287 | SV4-CA37-S4W-863015 | CA37 - SEAM WELDS AND INSTALLATION OF MK#50, MK#132 |
| 4288 | SV4-PGS-P0W-863127 | FABRICATE AND INSTALL PGS SMALL BORE HP NITROGEN PIPING SHOWN ON ISOMETRIC DRAWING # SV4-PGS-PLW-879, 880, 881, 952, 953, 954, 955, 956 |
| 4289 | SV4-CDS-PHW-860885 | FABRICATE AND INSTALL PIPING SUPPORTS FOR CDS ON 100' ELEVATION |
| 4290 | SV4-FWS-PHW-860898 | INSTALLATION OF FWS PIPING SUPPORTS ELEVATION 120' |
| 4291 | SV4-FPS-P0W-800001 | TB- INSTALL FPS LARGE BORE PIPE ELEV. 100'-0" |
| 4292 | SV4-FPS-P0W-800004 | TB- INSTALL FPS LARGE BORE PIPE ELEV. 100'-0" |
| 4293 | SV4-FPS-P0W-800005 | TB- INSTALL FPS LARGE BORE PIPE ELEV. 100'-0" |
| 4294 | SV4-HDS-P0W-800000 | TB- INSTALL HDS LARGE BORE PIPE ELEV. 100'-0" |
| 4295 | SV4-HDS-P0W-800001 | TB- INSTALL HDS LARGE BORE PIPE ELEV. 100'-0" |
| 4296 | SV4-WWS-PHW-800000 | TB- INSTALL WWS PIPE SUPPORTS ELEV. 100'-0" |
| 4297 | SV3-WWS-PHW-860662 | FABRICATION AND INSTALLATION OF WWS PIPING SUPPORTS |
| 4298 | SV4-CAS-P0W-ME2873 | FABRICATE AND INSTALL CAS BORE PIPING SHOWN ON ISOMETRIC DRAWING # SV4-CAS-PLW-776, 777, 778, 778, 784, AND 799 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 4299 | SV3-2039-ERW-862118 | INSTALLATION OF CABLE TRAY RACEWAY IN THE UNIT 3 TURBINE BUILDING, ELEVATION 100', AREA 9 |
| 4300 | SV3-2039-ERW-862121 | INSTALLATION OF CABLE TRAY RACEWAY COVERS IN THE UNIT 3 TURBINE BUILDING, ELEVATION 100', AREA 9 |
| 4301 | SV3-2039-ERW-862120 | INSTALLATION OF CABLE TRAY RACEWAY IN THE UNIT 3 TURBINE BUILDING, ELEVATION 100', AREA 9 |
| 4302 | SV4-CCS-PHW-861617 | INSTALLATION OF PIPE SUPPORTS FOR SV4-CCS-PLW-522 AND 540 |
| 4303 | SV3-2035-SHW-862410 | ELECTRICAL CABLE TRAY WELDED SUPPORTS FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 100' 0", AREA 5 |
| 4304 | SV3-2032-SHW-862425 | ELECTRICAL CABLE TRAY WELDED SUPPORT FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 100' 0", AREA 2 |
| 4305 | SV4-CCS-P0W-861616 | INSTALLATION OF PIPING FOR SV4-CCS-PLW-522 & -540 |
| 4306 | SV0-0000-CCW-CV5529 | MISCELLANEOUS GROUTING IN 300 SERIES BUILDINGS/YARD |
| 4307 | SV4-MH20-EYW-863215 | 220 TON BRIDGE CRANE MAINLINE SYSTEM ASSEMBLY FOR THE UNIT 4 TURBINE BUILDING IN ROOM 20600 ( CONDUCTOR BAR ) |
| 4308 | SV4-WRS-PHW-800001 | Install Large Bore Pipe Supports Per SV4-WRS-PLW-52B |
| 4309 | SV3-12171-S7W-800000 | UNIT 3 AUX BLDG SPREADER PLATE INSTALLATION, ROOM 12171, FLOOR ELEV 66'-6" |
| 4310 | SV4-WWS-PHW-863100 | INSTALLATION AND FABRICATION OF WASTE WATER SYSTEM(WWS) PIPING SUPPORTS |
| 4311 | SV4-CDS-PHW-860331 | INSTALL PIPE SUPPORTS FOR TURBINE ISLAND 4 CONDENSATE SYSTEM ROOM 20300, 20600, 20700 |
| 4312 | SV0-0000-EGW-862959 | INSTALLATION OF GROUND GRID AND ASSOCIATED GROUNDING FOR SITE GRID AREA LOCATION'S K1500 AND L1500 |
| 4313 | SV4-CA01-S4W-861773 | CA01-SUBASSEMBLY 05 ELEV 107' TO 119' OLPS AND WELDED ATTACHMENTS |
| 4314 | SV3-WWS-PHW-860652 | FABRICATION AND INSTALLATION OF WWS PIPING SUPPORTS |
| 4315 | SV3-PWS-P0W-860817 | POTABLE WATER SYSTEM PIPING INSTALLATION |
| 4316 | SV3-PWS-P0W-860816 | INSTALLATION OF SV3 TURBINE BUILDING PWS PIPING |
| 4317 | SV4-CCS-P0W-861618 | INSTALLATION OF PIPING FOR SV4-CCS-PLW-530 & -550 |
| 4318 | SV3-PWS-P0W-863266 | INSTALLATION OF SV3 TURBINE BUILDING PWS PIPING |
| 4319 | SV4-ME04-MEW-863330 | MSR MOISTURE SEPARATOR REHEATERS (MSS-ME-01A) |
| 4320 | SV3-VWS-PLW-ME2836 | INSTALLATION OF SMALL BORE VWS PIPING (INCLUDES ISOMETRICS SV3-VWS-PLW-386) |
| 4321 | SV4-WLS-PHW-861369 | INSTALLATION OF PIPE SUPPORTS FOR ISOMETRICS SV4-WLS-PLW-590, -591 & -710 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 4322 | SV3-1152-SHW-800004 | Fabricate welded conduit supports for Containment Area 2 Elev. 135'3" that are associated with SP-L26, SP-L27 and SP-L28 |
| 4323 | SV3-SSS-PHW-860597 | INSTALLATION OF SECONDARY SAMPLING SYSTEM (SSS) |
| 4324 | SV4-RNS-MLW-800001 | ASME III - Installation of Containment Vessel Penetration SV4-RNS-PY-C02 (P20) |
| 4325 | SV4-FWS-P0W-863271 | INSTALL PIPING FOR TURBINE ISLAND 4 FEED WATER SYSTEM ROOM 203000 |
| 4326 | SV3-0150-ERW-861866 | CABLE TRAY SUPPORT FOR TRANSFORMER PHASE A |
| 4327 | SV3-0150-ERW-861867 | CABLE TRAY SUPPORT FOR TRANSFORMER PHASE B ( ZAS-ET-1B ) |
| 4328 | SV4-4031-C0W-850001 | UNIT 4 ANNEX BLDG BATTERY/CHARGER ROOM INTERIOR WALLS ELEV 100'-0" TO 116'-10" |
| 4329 | SV4-FWS-PHW-863272 | INSTALL PIPE SUPPORTS FOR TURBINE ISLAND 4 FEED WATER SYSTEM ROOM 20300 |
| 4330 | SV4-DTS-PHW-863256 | DEMINERALIZED WATER TREATMENT TURBINE BUILDING ROOM 20300 DTS-MS-05 A/B TO WASTE |
| 4331 | SV4-VYS-PHW-860345 | AUXILIARY STEAM SUPPLY SYSTEM TURBINE BUILDING ROOM 20400 FROM ASS TO HEAT EXCHANGER |
| 4332 | SV4-CA37-S4W-863106 | UNIT 4 CA37 RIGGING MODIFICATION |
| 4333 | SV4-CA37-S4W-863017 | CA37 - OLP INSTALL AND OLP & EMBED COUPLER INSTALLATION |
| 4334 | SV4-CA37-S4W-863020 | UNIT 4 CA37 STUD INSTALLATION |
| 4335 | SV3-0150-ERW-861868 | CABLE TRAY SUPPORT FOR TRANSFORMER PHASE C |
| 4336 | SV4-1212-ERW-861221 | INSTALL DESIGN ROUTED CABLE TRAY AND SUPPORTS FOR SPARE BATTERY ROOM 12103 EL. 66'-6" |
| 4337 | SV4-WWS-PHW-800034 | TB-Install WWS Large Bore Pipe SUPPORTS- EL 120'-6" |
| 4338 | SV4-MS85-MTW-863174 | INSTALLATION OF LUBE OIL FLUSHING UNIT SV4-LOS-MS-05 |
| 4339 | SV3-PWS-PHW-863265 | FABRICATION AND INSTALLATION OF SV3 TURBINE BUILDING POTABLE WATER SYSTEM PIPING SUPPORTS |
| 4340 | SV4-FPS-P0W-800007 | FPS Piping Installation 100' Elevation |
| 4341 | SV3-FPS-PHW-862830 | INSTALLATION OF FPS PIPE SUPPORTS IN ANNEX 3 |
| 4342 | SV3-KB22-KBW-863241 | REWORK WLS PIPING ON MODULE KB22 |
| 4343 | SV4-WLS-PHW-861959 | FABRICATION / INSTALLATION OF WLS PIPING SUPPORTS SHOWN ON ISOMETRIC DRAWINGS SV4-WLS-PLW-370 |
| 4344 | SV4-HDS-PHW-860906 | FABRICATION AND INSTALLATION OF SV4 TURBINE BUILDING HDS PIPE SUPPORTS |
| 4345 | SV3-2058-SHW-861524 | CABLE TRAY WELDED STAND SUPPORT INSTALLATION FOR TURVINE 3, AREA 8 EL 141'3" |
| 4346 | SV4-1208-CCW-851004 | Course 4 Concrete Placement |
| 4347 | SV3-ML05-MLW-800007 | INSTALL PENETRATIONS SV3-11300-ML-P19 & SV3-11300-ML-P20 |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 4348 | SV3-MP03-EMW-863282 | INSTALL AC MOTORS TO CONDENSATE PUMPS IN THE UNIT 3 TURBINE BUILDING (BETWEEN COL. 17 & 18, COL. J.15 & I.5 |
| 4349 | SV3-ME01-PHW-860975 | CONDENSER C HEATER DRAIN PIPE SUPPORTS |
| 4350 | SV4-CA01-S4W-861191 | CA01-SA01 - ELEV 96' TO 107' OLPSS AND WELDED ATTACHMENTS |
| 4351 | SV4-CA01-S4W-861768 | CA01-SA01 - ELEV 107'-119' OLPS |
| 4352 | SV4-WLS-PLW-81CW-FP1014 | HYDROSTATIC TEST THE FABRICATED SPOOLS SV4-WLS-PLW-81CW-3A/3B |
| 4353 | SV3-CWS-ERW-863235 | UNIT 3 TOP DECK 1" EMBEDDED CONDUITS |
| 4354 | SV3-2060-CPW-850000 | UNIT 3, TURBINE BUILDING, 170' ELEV. PRECAST PANELS |
| 4355 | SV4-0000-SSW-863284 | UNIT 4 TRANSFORMER FOUNDATION STRUCTURAL STEEL |
| 4356 | SV3-VAS-MDW-860228 | R161 MODULE HVAC COMPLETION |
| 4357 | SV3-2051-SHW-862677 | ELECTRICAL CABLE TRAY WELDED SUPPORT FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING ELEVATION 141'3" AREA 1 |
| 4358 | SV3-PWS-PHW-863263 | FABRICATION AND INSTALLATION OF SV3 TURBINE BUILDING POTABLE WATER SYSTEM PIPING SUPPORTS |
| 4359 | SV3-PWS-PHW-863264 | FABRICATION AND INSTALLATION OF SV3 TURBINE BUILDING POTABLE WATER SYSTEM PIPING SUPPORTS |
| 4360 | SV3-KB37-KBW-863233 | REWORK WLS PIPING ON MODULE KB37 |
| 4361 | SV3-KB38-KBW-863234 | REWORK WLS PIPING ON MODULE KB38 |
| 4362 | SV3-FPS-P0W-800002 | Installation of Large Bore Pipe Per ISO SV3-FPS-PLW-51R |
| 4363 | SV3-FPS-P0W-800007 | Containment Building-Installation of Large Bore Pipe per ISO SV3-FPS-PLW-53B |
| 4364 | SV3-2034-SHW-800001 | Electrical Welded Cable Tray Support Fab and Installation in Unit 3 Turbine Building, Elevation 100' 0", Area 4 |
| 4365 | SV4-CDS-P0W-800002 | TB-Install CDS Large Bore Pipe - EL 100' |
| 4366 | SV4-VWS-PHW-861584 | INSTALLATION OF PIPE SUPPORTS FOR SV4-VWS-PLW-390 |
| 4367 | SV3-FPS-PHW-854231 | LARGE BORE SUPPORT FOR ISOS SV3-FPS-PLW-554 & SV3-FPS-PLW-55S |
| 4368 | SV3-FPS-PHW-854241 | FAB AND INSTALL LB PIPE SUPPORTS PER ISO'S SV3-FPS-PLW-552, PLW-553 AND PLW-55Q |
| 4369 | SV3-FPS-PHW-854212 | FAB & INSTALL SUPPORTS FOR ISO'S SV3-FPS-PLW-55G, -55H, -551 & -55J |
| 4370 | SV3-FPS-PHW-854203 | FAB AND INSTALL CONTAINMENT FPS LOWER RING HEADER SUPPORTS PER ISO'S SV3-FPS-PLW-556, 558, 55T & 55X |
| 4371 | SV4-FPS-P0W-861568 | FABRICATION / INSTALLATION OF FPS PIPING SHOWN ON ISOMETRIC DRAWINGS SV4-FPS-PLW-710, - 720 AND 723 |
| 4372 | SV4-MP80-MTW-863173 | INSTALLATION OF LUBE OIL TRANSFER PUMP SV4-LOS-MP-05 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 4373 | SV3-PWS-PHW-860589 | FABRICATE AND INSTALL SV3 TURBINE BUILDING POTABLE WATER PIPING SYSTEM SUPPORTS |
| 4374 | SV4-VWS-P0W-861579 | INSTALLATION OF PIPING FOR SV4-VWS-PLW-290 |
| 4375 | SV3-FPS-PHW-854211 | LARGE BORE SUPPORTS FIR ISO'S SV3-FPS-PLW-55D, 55V, 55E, 55F & 55W |
| 4376 | SV3-1211-ERW-800002 | Install Field Routed Conduit in AuxilIary Building Area 1, Elev. 66'6", Room 12104 |
| 4377 | SV3-ME3B-MEW-800001 | Installation of Plate Heat Exchanger SFS-ME-01B |
| 4378 | SV3-ME2Q-MEW-800000 | Installation of Miniflow Heat Exchanger CVS-ME-03A |
| 4379 | SV3-CA20-S7W-800001 | CA20, HVAC Spreader Plate Installations, Room 12162 |
| 4380 | SV3-CA20-S7W-800002 | CA20, HVAC Spreader Plate Installations, Room 12163 |
| 4381 | SV3-CA20-S7W-800003 | CA20, HVAC Spreader Plate Installations, Room 12264 |
| 4382 | SV3-CA20-S7W-800006 | CA20, HVAC Spreader Plate Installations, Room 12262 |
| 4383 | SV3-CA20-S7W-800007 | CA20, HVAC Spreader Plate Installations, Room 12166 |
| 4384 | SV3-CA20-S7W-800008 | CA20, HVAC Spreader Plate Installations, Room 12167 |
| 4385 | SV3-CA20-S7W-800009 | CA20, HVAC Spreader Plate Installations, Room 12268 |
| 4386 | SV3-CA20-S7W-800010 | CA20, HVAC Spreader Plate Installations, Room 12269 |
| 4387 | SV0-YFS-P0W-863252 | START UP SUPPORT FOR YFS SYSTEM @ BUILDING 315 |
| 4388 | SV3-ML05-MLW-800003 | Containment Building-Installation of Pipe Penetrations in Room 11300 |
| 4389 | SV3-KB33-KBW-863175 | COMPLETE PIPING AND PIPING SUPPORTS INSTALLATION ON MODULE KB33 |
| 4390 | SV3-ECS-TIW-862099 | INSTALLATION OF "TEMPORARY MODIFICATION" OF SUPPORTS & CABLES IN SUPPORT OF INITIAL ENERGIZATION FOR UNIT SV3 ANNEX & TURBINE |
| 4391 | SV4-VWS-PHW-861588 | INSTALLATION OF PIPE SUPPORTS FOR SV4-VWS-PLW-680 |
| 4392 | SV4-WLS-PHW-ME3288 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING WLS-PLW-215 |
| 4393 | SV3-4032-SHW-862720 | FABRICATE AND INSTALL CABLE TRAY SUPPORTS ANNEX BLDG AREA 2 ELEV 100' BETWEEN COLUMN LINES 7.1/7.8 & H/G |
| 4394 | SV3-4032-SHW-862721 | FABRICATE AND INSTALL CABLE TRAY SUPPORTS ANNEX BLDG AREA 2 ELEV 100' BETWEEN COLUMN LINES 7.1/7.8 & F/G |
| 4395 | SV3-2051-SHW-862673 | ELECTRICAL CABLE TRAY WELDED SUPPORT FABRICATION & INSTALLATION IN THE UNIT 3 TURBINE BUILDING ELEV 141'3" AREA 1 |
| 4396 | SV3-2051-SHW-862672 | ELECTRICAL CABLE TRAY WELDED SUPPORT FABRICATION & INSTALLATION IN THE UNIT 3 TURBINE BUILDING ELEV 141'3" AREA 1 |
| 4397 | SV3-KB33-KBW-862944 | KB33 COMPLETE MODULE STRUCTURAL, HVAC, EQUIPMENTS INSTALLATION |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 4398 | SV3-CAS-PHW-850041 | INSTALLATION/FABRICATION OF SMALL BORE PIPE SUPPORTS FOR ISO'S CAS-PLW-41C, 41F, 41G |
| 4399 | SV3-1212-ERW-800001 | Install Field Routed Non 1E Couduit in Aux Area 2 Elev 66'6" Room 12102 |
| 4400 | SV3-WLS-PHW-800008 | Install SB Pipe Supports Per Isometric SV3-WLS-PLW-33B |
| 4401 | SV3-ML05-MLW-800005 | ASME III: Installation of Penetration 12306-ML-P25 |
| 4402 | SV3-1120-CCW-CV1817 | PLACEMENT, CURING, AND REPAIR OF CONCRETE INSIDE THE CV UP TO ELEV 80'-0" AND ELEV 80'-6" |
| 4403 | SV3-1212-ERW-800003 | Install Field Routed Class 1E Conduit in AuxilIary Building Area 2, Elev. 66'6", Room 12101 |
| 4404 | SV4-WWS-PHW-860932 | FABRICATE AND INSTALL SV4- TURBINE BUILDING WASTE WATER SYSTEM PIPE SUPPORTS |
| 4405 | SV4-CA37-S4W-863016 | CA37 - MISC STRUCTURAL SHAPE INSTALLATION |
| 4406 | SV4-CA20-S4W-800008 | CA20, Leak Chase Repairs |
| 4407 | SV3-CAS-P0W-863122 | INSTALLATION OF CAS PIPING IN ANNEX 3 ( SWITCHGEAR ROOM ) |
| 4408 | SV3-CDS-P0W-863013 | INSTALLATION OF CDS PIPING FROM CONDENSATE PUMP DISCHARGE VENTS TO CONDENSER (ISOMETRICS SV3-CDS-PLW-744/745/746 |
| 4409 | SV4-TCS-P0W-860921 | INSTALLATION AND FABRICATION OF TURBINE BUILDIN CLOSED COOLING WATER SYSTEM (TCS) |
| 4410 | SV4-FPS-PHW-860335 | INSTALL FPS PIPING SUPPORTS IN UNIT 4 TURBINE BUILDING |
| 4411 | SV4-HDS-PHW-863195 | FABRICATE AND INSTALL HDS PIPING SUPPORTS |
| 4412 | SV3-FPS-PHW-862832 | INSTALLATION OF FPS PIPE SUPPORTS IN ANNEX 3 |
| 4413 | SV3-PWS-PHW-862368 | INSTALLATION OF ANNEX BLDG PWS PIPE SUPPORTS (ISO SV3-PWS-PLW-115,-457 & -458 |
| 4414 | SV4-1232-SAW-850000 | UNIT 4, AUXILIARY BUILDING STUDS FOR 100' ELEV, AREA 2 |
| 4415 | SV3-WLS-PLW-80BY-FP907 | REWORK SPOOLS SV3-WLS-PLW-80BY-1A,-1B & -2 AND SV3-WLS-PLW-80FY-1A,-1B,-1C & -2 |
| 4416 | SV3-2034-SHW-800000 | Electrical Cable Tray Support Fab and Installation in Unit 3 Turbine Building, Elevation 100' 0", Area 4 |
| 4417 | SV3-1212-ERW-800004 | Install Field Routed Non 1E Couduit in Aux Area 2 Elev 66'6" Room 12102 |
| 4418 | SV3-KB33-ERW-800000 | INSTALLATION OF ELECTRICAL CABLE TRAY IN MODULE KB33 |
| 4419 | SV3-WLS-PLW-460-FP1010 | MODIFICATION OF PIPE SPOOL SV3-WLS-PLW-460-1 |
| 4420 | SV3-RWS-P0W-863001 | INSTALL RWS 34" AND 20" HDPE PIPING TO UNIT 3 COOLING TOWER |
| 4421 | SV3-RWS-THW-863144 | HYDROTEST RWS 34" AND 20" HDPE PIPING TO UNIT 3 COOLING TOWER |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 4422 | SV3-CA01-CCW-800009 | CA01 West Steam Generator Concrete, Wall Placement, Section #7, 10b, 10c, 10d, 11, 12, 13 & 15 up to 153'-0" |
| 4423 | SV4-2050-SSW-863283 | UNIT4 TURBINE BUILDING SEQUENCE 18 ROOMS 20501, 20502 & 20503 |
| 4424 | SV4-SFS-P0W-861547 | INSTALLATION OF PIPING FOR SV4-SFS-PLW-12C & 121 |
| 4425 | SV3-1212-SHW-800008 | Fabricate and Install Field-Routed Conduit Supports in Room 12102, Area 2, Elev. 66'-6" |
| 4426 | SV3-CWS-CYW-863550 | PHASE 3 JOINT GROUTING AND FLOWABLE FILL |
| 4427 | SV4-KB23-THW-863504 | HYDRO TESTING OF WLS PIPING ON MODULE KB23 |
| 4428 | SV3-CVS-PHW-ME2930 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING SV3-CVS-PLW-801 |
| 4429 | SV4-WWS-P0W-863287 | INSTALL WASTE WATER SYSTEM PIPING, ISOMETRICS SV4-WWS-PLW-506, -816, 924 |
| 4430 | SV3-WWS-P0W-863285 | INSTALL WASTE WATER SYSTEM PIPING, ISOMETRICS SV3-WWS-PLW-505, -923, 980 |
| 4431 | SV3-WWS-PHW-860653 | FABRICATE AND INSTALL SV3 TURBINE BUILDING WASTE WATER (WWS) SYSTEM PIPING SUPPORTS |
| 4432 | SV0-0000-C0W-863503 | PERSONNEL ACCESS POINT PEDESTRIAN BRIDGE |
| 4433 | SV3-2026-SHW-862477 | INSTALLATION OF ELECTRICAL CABLE TRAY WELDED SUPPORTS IN THE UNIT 3 TURBINE BUILDING ELEV 82'-9" AREA 6 |
| 4434 | SV4-RWS-THW-863145 | Hydrotest RWS 34" and 20" HDPE Piping to Unit 4 Cooling Tower |
| 4435 | SV4-WWS-THW-863143 | HYDROTEST WWS 20" HDPE PIPING FROM UNIT 4 COOLING TOWER |
| 4436 | SV3-2044-SHW-861967 | ELECTRICAL CABLE TRAY WELDED SUPPORTS |
| 4437 | SV3-MSS-PLW-452-FP348 | MODIFY PIPE SPOOL |
| 4438 | SV4-WWS-P0W-863000 | INSTALL WWS 20" HDPE PIPING FROM UNIT 4 COOLING TOWER |
| 4439 | SV4-VWS-PHW-855014 | Containment Building-Installation of Supports: ISO-SV4-VWS-PLW-502 |
| 4440 | SV3-PCS-PHW-800001 | INSTALL ASME III PIPE SUPPORTS PER SV3-PCS-PLW-035 |
| 4441 | SV4-2070-SSW-863274 | UNIT 4 TURBINE BUILDING ROOF DECKING, SEQUENCE 14, 15 AND 16 |
| 4442 | SV3-2044-SHW-861966 | ELECTRICAL CABLE TRAY WELDED SUPPORTS |
| 4443 | SV3-2045-SHW-861893 | ELECTRICAL CABLE TRAY WELDED SUPPORTS FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING, ELEVATION 120'6", AREA 5 |
| 4444 | SV3-4000-SHW-863324 | FABRICATE AND INSTALL TYPICAL FIELD ROUTED CONDUIT SUPPORTS C-131 ANNEX BUILDING ALL AREAS AND ELEVATIONS, BOOK 1 |
| 4445 | SV3-CCS-P0W-800074 | Install Large Bore Pipe per SV3-CCS-PLW-516 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 4446 | SV3-CAS-PHW-850895 | INSTALL ISOMETRICS SV3-CAS-PLW-895 SMALL BORE PIPE SUPPORTS |
| 4447 | SV3-1214-SHW-862408 | FABRICATE & INSTALL DESIGNED CONDUIT SUPPORTS AREA 4 ELEV 66'-6" |
| 4448 | SV3-CAS-P0W-862826 | INSTALLATION OF ANNEX BLDG CAS PIPING (ISO-CAS-PLW-20S, 25S, 25U, 25V, 202, 203, 205, 211, 217, 224, 225, 227, & 229) |
| 4449 | SV4-WWS-THW-862953 | HYDROTEST UNIT 4 YARD WASTE WATER SYSTEM UNDERGROUND STEEL PIPING. |
| 4450 | SV4-MS18-MSW-800000 | TB - Condenser Air Removal Pump Skids (CMS-MS-01A/B/C/D) |
| 4451 | SV3-1230-CRW-800008 | 100'-0" to 115'-6", CL 2 Wall, Rebar Fabrication & Installation (Wall 98) |
| 4452 | SV3-4000-SHW-862404 | FABRICATION AND INSTALLATION OF TYPICAL FIELD ROUTED CONDUIT SUPPORTS, DETAIL C-94, ANNEX BUILDING, ALL AREAS / ELEVATIONS. BOOK 1 |
| 4453 | SV4-CA01-S4W-861769 | CA01-SA01 ELEV 107" - 119" DWA |
| 4454 | SV3-4032-SHW-862719 | FABRICATE AND INSTALL CABLE TRAY SUPPORTS, ANNEX BLDG. AREA 2, ELEV. 100', BETWEEN COLUMN LINES 6/7.1 & E/F. |
| 4455 | SV4-1130-SLW-861200 | Upender Pit, Fabrication |
| 4456 | SV3-1213-ERW-EL3680 | FABRICATE AND INSTALL FIELD ROUTED TYPICAL CONDUIT SUPPORT C15 FOR AUX BUILDING (AREAS 3 & 4) EL 66'-6" TO 82'-6" |
| 4457 | SV3-1213-ERW-EL3681 | FABRICATE AND INSTALL FIELD ROUTED TYPICAL CONDUIT SUPPORT C29 FOR AUX BUILDING (AREAS 3 & 4) EL 66'-6" TO 82'-6" |
| 4458 | SV3-1215-ERW-EL3683 | FABRICATE AND INSTALL FIELD ROUTED TYPICAL CONDUIT SUPPORT C13 FOR AUX BUILDING (AREAS 5 & 6) EL 66'-6" TO 82'-6" |
| 4459 | SV4-2037-SHW-863385 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE TURBINE BUILDING ELEVATION 100'-0" AREA 7 FROM COLUMNS 18 TO 19 & I.2 TO K.1 |
| 4460 | SV3-2000-PHW-863497 | INSTALLATION OF TEMPORARY SUPPORTS FOR FIRE PROTECTION SYSTEM |
| 4461 | SV4-2037-SHW-863388 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE TURBINE BUILDING, ELEVATION 100'-0", AREA 7 FROM COLUMNS 18 TO 20 & L.1 TO K.1 |
| 4462 | SV3-WLS-PHW-800001 | Install SB pipe supports per SV3-WLS-PLW-522 |
| 4463 | SV3-2068-SHW-863447 | ELECTRICAL CABLE TRAY SUPPLEMENTAL STEEL INSTALLATION IN THE TURBINE BUILDING UNIT 3, BELOW ELEVATION 230'-9", |
| 4464 | SV3-WLS-PHW-800000 | Install SB pipe supports per SV3-WLS-PLW-521 |
| 4465 | SV3-CVS-PHW-800004 | Install large bore pipe supports per SV3-CVS-PLW-532 |
| 4466 | SV3-RNS-PHW-861487 | FABRICATION/INSTALLATION OF RNS SMALL BORE PIPE SUPPORTS FOR ISO SV3-RNS-PLW-17U |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 4467 | SV3-WLS-P0W-800000 | Install small bore pipe per SV3-WLS-PLW-521 |
| 4468 | SV3-WLS-PHW-800004 | Install Small Bore Supports per Isometric SV3-WLS-PLW-524 |
| 4469 | SV3-RNS-PHW-ME9014 | FABRICATION/INSTALLATION OF SUPPORTS FOR ISO SV3-RNS-PLW-174 |
| 4470 | SV3-WLS-PHW-800003 | Install Small Bore Supports per Isometric SV3-WLS-PLW-533 |
| 4471 | SV4-FPS-PHW-863275 | FABRICATION AND INSTALLATION OF SV4 TURBINE BUILDING FPS PIPING SUPPORTS |
| 4472 | SV3-2044-SHW-861965 | ELECTRICAL CABLE TRAY WELDED SUPPORTS |
| 4473 | SV3-6030-C0W-850000 | DIESEL GENERATOR BUILDING CONCRERT SLAB AND FOUNDATION |
| 4474 | SV4-4040-CRW-863383 | AREA 3 WALLS FROM 107'2" TO 123'-8" REINFORCEMEN |
| 4475 | SV4-RNS-P0W-850180 | INSTALL PIPE ISO SV4-RNS-PLW-180 |
| 4476 | SV3-WWS-PHW-860663 | FABRICATE AND INSTALL SV3 TURBINE BUILDING WASTE WATER (WWS) SYSTEM PIPING SUPPORTS |
| 4477 | SV4-CA01-S4W-861770 | CA01-SA02 - ELEV 107' TO 119' OLPs AND WELDED ATTACHMENTS |
| 4478 | SV3-RNS-PHW-850023 | 3" LARGE BORE PIPE SUPPORT PER ISO: SV3-RNS-PLW-023 |
| 4479 | SV4-WWS-PHW-863288 | INSTALL WASTE WATER SYSTEM PIPE SUPPORTS ISOMETRICS SV4-WWS-PLW-506, 816, 924 |
| 4480 | SV3-VYS-PHW-863039 | INSTALLATION OF PIPE SUPPORTS IN ANNEX 3 |
| 4481 | SV3-RWS-P0W-863381 | UNIT 3 RAW WATER SYSTEM PIPING NEAR THE BLOWDOWN SUMP |
| 4482 | SV4-RWS-P0W-863382 | UNIT 4 RAW WATER SYSTEM PIPING AND SUPPORT NEAR THE BLOWDOWN SUMP |
| 4483 | SV4-KB37-KBW-863074 | SITE COMPLETION OF MODULE KB37 FABRICATION |
| 4484 | SV3-PWS-PHW-ME6979 | Installation of Annex Bldg PWS Pipe Supports (Isometrics SV3-PWS-PLW-150, 156, 157, 454, 455, 471). |
| 4485 | SV3-WWS-PHW-860654 | FABRICATE AND INSTALL SV3 TURBINE BUILDING WASTE WATER SYSTEM PIPING SUPPORTS |
| 4486 | SV3-VWS-P0W-862835 | INSTALLATION OF VWS PIPING IN ANNEX 3 |
| 4487 | SV0-SDS-PLW-ME1148 | Install Sanitary Drain Lines Between Lift Stations MS-501 and MS-502 |
| 4488 | SV4-1220-CCW-CV10085 | UNIT 4 CORE BUILDING IN CONCRETE PLACEMENT OUTSIDE THE CVBH AT ELEV. 72'-6" |
| 4489 | SV4-RWS-P0W-863002 | INSTALL RWS 34" AND 20" HDPE PIPING TO UNIT 4 COOLING TOWER |
| 4490 | SV4-PXS-P0W-800022 | Install large bore pipe per SV4-PXS-PLW-029 |
| 4491 | SV4-CA33-S5W-863332 | CA33 INSTALL SHIOPPED LOOSE PARTS |
| 4492 | SV4-CA01-S4W-861780 | CA01 SUBASSEMBLY 03 ELEV > 119' OLPs AND WELDED ATTACHMENTS |
| 4493 | SV3-CA01-S8W-CV4043 | U3 CONTAINMENT INSTALLATION OF CA01 MODULE AT ELEV. 83'-0" |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 4494 | SV3-4034-CEW-CV2621 | Annex Area 4 Foundation Embed Plates And Anchor Bolts |
| 4495 | SV3-CCS-P0W-ME2774 | INSTALLATION OF LARGE BORE CCS PIPING (INCLUDES ISOMETRICS: SV3-CCS-PLW-080, 082 |
| 4496 | SV4-4034-C0W-863506 | AREA 4 CONTROLLED DENSITY FILL AND MUDMAT PLACEMENT |
| 4497 | SV4-VWS-PHW-855028 | INSTALL ISOMETRIC SV4-VWS-PLW-52A LARGE BORE PIPE SUPPORTS |
| 4498 | SV4-VWS-P0W-855011 | LARGE BORE PIPE SV4-ISOMETRIC SV4-VWS-PLW-50L |
| 4499 | SV3-2026-SHW-862476 | INSTALLATION OF ELECTRICAL CABLE TRAY WELDED SUPPORTS IN THE UNIT 3 TURBINE BUILDING ELEV 82'-9", AREA 6 |
| 4500 | SV4-CA01-S4W-861771 | CA01-SA03 ELEV 107' - 119' OVERLAY PLATES (OLP) AND DIRECT WELDED ATTACHMENTS (DWA) |
| 4501 | SV3-CCS-P0W-862864 | INSTALLATION OF CCS PIPING IN ANNEX 3 |
| 4502 | SV4-KB38-KBW-863075 | SITE COMPLETION OF MODULE KB-38 FABRICATION |
| 4503 | SV4-WWS-P0W-862175 | INSTALLATION OF ANNEX BLDG WWS PIPING (ISO SV4-WWS-PLW-467, 468, 469, 956, 957, 958, 959 & 960) |
| 4504 | SV3-PXS-P0W-800034 | Install ASME III Valve SV3-PXS-PL-V016B and Spool SV3-PXS-PLW-020-1F per ISO SV3-PXS-PLW-020 |
| 4505 | SV3-ML05-MLW-800004 | INSTALL ASME III PIPE AND PENETRATION PER ISO SV3-SFS-PLW-160 |
| 4506 | SV3-PXS-PHW-850221 | FABRICATE AND INSTALL LB PIPE SUPPORTS IAW ISO SV3-PXS-PLW-221 |
| 4507 | SV4-WRS-P0W-800007 | 1" SMALL BORE PIPE PER ISO: SV4-WRS-PLW-82J |
| 4508 | SV3-PCS-P0W-800003 | Install small bore pipe per SV3-PCS-PLW-450 |
| 4509 | SV4-WWS-PHW-862176 | INSTALLATION OF ANNEX BLDG WWS PIPE SUPPORTS (ISO SV4-WWS-PLW-467, 468, 469, 956, 957, 958, 959 & 960) |
| 4510 | SV4-2070-SUW-863273 | UNIT 4 TURBINE BUILDING STRUCTURAL STEEL FRAMIN SEQUENCE 16 |
| 4511 | SV3-2043-SHW-861610 | ELECTRICAL CABLE TRAY TRAPEZE SUPPORTS FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BUILDING ELEV 120'6" AREA 3 |
| 4512 | SV3-PXS-P0W-ME3832 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-100, -101, -102 (LINE NUMBERS PXS-PL-L180B) |
| 4513 | SV3-PXS-P0W-ME3833 | ASME SECTION III - FABRICATION/INSTALLATION OF ISOMETRIC# SV3-PXS-PLW-110, -111, -112, -113 (LINE NUMBERS PXS-PL-L180A) |
| 4514 | SV4-1230-CRW-800008 | 100'-0" to 117'-6", CL 1 Wall, Rebar Fabrication & Installation (Wall 88) |
| 4515 | SV4-1230-CRW-800009 | 100'-0" to 117'-6", CL 1 Wall, Rebar Installation (Wall 89) |
| 4516 | SV3-CDS-PLW-01N-FP673 | MODIFICATION OF PIPE SPOOL SV3-CDS-PLW-01N-2 |
| 4517 | SV4-VWS-PLW-286-FP494 | MODIFICATION OF PIPE SPOOLS SV4-VWS-PLW-286-1 THRU -6 |
| 4518 | SV4-TDS-PLW-303-FP492 | MODIFICATION OF PIPE SPOOLS SV4-TDS-PLW-303-2 AND -3 |

**Exhibit V – Legacy, WIP, and Completed Work Packages**

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 4519 | SV4-WLS-PLW-81AD-FP1109 | REWORK SPOOLS SV4-WLS-PLW-81AD-2, -3A & -3B AND SV4-WLS-PLW-81ED-2, -3A, -3B & -3C |
| 4520 | SV4-WLS-PLW-81AF-FP1110 | REWORK SPOOLS SV4-WLS-PLW-81AF-2, -3A & -3B AND SV4-WLS-PLW-81EF-2, -3A, -3B & -3C |
| 4521 | SV4-DWS-PLW-929-FP1057 | MODIFICATION OF PIPE SPOOL SV3-DWS-PLW-929-1 THRU -3 |
| 4522 | SV3-DWS-PLW-930-FP1059 | MODIFICATION OF PIPE SPOOLS SV3-DWS-PLW-830-2 THRU -5 |
| 4523 | SV3-WWS-PLW-515-FP1099 | MODIFICATION OF PIPE SPOOLS SV3-WWS-PLW-513-1A, -1B, -C & 2 |
| 4524 | SV3-VYS-P0W-863038 | INSTALLATION OF PIPING IN ANNEX 3 |
| 4525 | SV4-VWS-P0W-855031 | INSTALL LARGE BORE PIPE ISOMETRIC SV4-VWS-PLW-51A |
| 4526 | SV4-1233-SSW-850000 | AUXILIARY BUILDING STRUCTURAL STEEL FROM ELEV 82'-6" UP TO 100'-0" AREA 3 |
| 4527 | SV4-MH20-MHW-863170 | ASSEMBLY AND INSTALLATION OF 15T TURBINE CRANE |
| 4528 | SV4-MH20-MHW-863168 | ASSEMBLY AND INSTALLATION OF 220T TURBINE CRANE |
| 4529 | SV3-VWS-PHW-800001 | Install large bore pipe support per SV3-VWS-PLW-920 |
| 4530 | SV3-CVS-P0W-800006 | ASME III INSTALL LB PIPING FROM ISO SV3-CVS-PLW-532 |
| 4531 | SV3-CAS-P0W-800014 | Install Small Bore Pipe Per SV3-CAS-PLW-833 |
| 4532 | SV3-1130-C0W-850003 | Containment Concrete Placement, West Side to Elev. 102'-11-1/2" |
| 4533 | SV3-MS10-MEW-860243 | INSTALLATION OF TURBINE BUILDING FIRST BAY AHUs SV3-VTS-MS-03A & 03B |
| 4534 | SV3-CVS-P0W-800004 | Install small bore pipe per SV3-CVS-PLW-522 |
| 4535 | SV4-MS60-MSW-863329 | INSTALLATION OF AUXILIARY BOILER DEAERATOR SV4-ASS-ME-01 |
| 4536 | SV4-1232-SSW-850000 | AUXILIARY BUILDING STRUCTURAL STEEL FROM ELEV 82'-6" UP TO 100'-0" AREA 2 |
| 4537 | SV3-WWS-PHW-ME2683 | INSTALLATION OF ANNEX WWS PIPING SUPPORTS (FOR WP SV3-WWS-P0W-ME2633) |
| 4538 | SV0-0000-XEW-CV0267 | Erosion Control Measures per NOI-20 in Support of the RWI Site Development |
| 4539 | SV0-0000-XYW-CV0239 | Maintenance and Removal of Various NOI's |
| 4540 | SV0-142-PPW-ME0306 | PWS & SDS FOR BUILDING 142: SAFETY, MEDICAL AND FIRE FACILITY |
| 4541 | SV0-869-XVW-CV1421 | Vehicle Barrier Ditch |
| 4542 | SV0-RWS-CCW-CV0964 | RWS DUCT BANK TO THE RIVER WATER INTAKE |
| 4543 | SV0-YFS-PLW-ME0265 | FABRICATION AND INSTALLATION OF THE YARD FIRE WATER SYSTEM HDPE PIPING FOR TRENCH 7 |
| 4544 | SV3-CA01-S4W-CV6061 | CA01-43 PERMANENT WELDED ATTACHMENT INSTALLATION |
| 4545 | SV3-CA01-S5W-CV4285 | CA01-22 N&D SV3-CA01-GNR-000067 REWORK |
| 4546 | SV3-CA20-S4W-CV0438 | Install CA20-66 Floor into CA20 SA4 |
| 4547 | SV4-CAS-THW-863505 | HYDROSTATIC TESTING OF CAS PIPING ON MODULE R161 |
| 4548 | SV3-CVS-PLW-ME0560 | INSTALLATION OF LARGE BORE CVS PIPING. INCLUDES ISOMETRICS SV3-CVS-PLW-561 AND 562 |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 4549 | SV3-DWS-PLW-ME0930 | Fabricate and Install Small Bore Elevation 1 DWS Piping Iso SV3-DWS-PLW-773 |
| 4550 | SV3-HDS-PHW-ME1366 | FABRICATE AND INSTALL HEATER DRAIN PIPE SUPPORTS ON FEEDWATER HEATER DRAIN COOLER 7B |
| 4551 | SV3-ME01-PLW-ME1011 | Unit 3 Condenser C: Installation of Upper Shell Nozzles |
| 4552 | SV3-MT6F-MEW-ME3568 | INSTALLATION OF MAIN FEEDWATER PUMP DRAIN COLLECTOR (FWS-MT-01) |
| 4553 | SV3-PXS-PLW-ME0931 | Fabricate and Install Small Bore Elevation 1 PXS Piping Iso SV3-PXS-PLW-824 |
| 4554 | SV3-WLS-MTW-ME0746 | WLS EFFLUENT HOLDUP TANK B INSTALLATION |
| 4555 | SV3-WLS-MTW-ME0747 | WASTE HOLDUP TANK A INSTALLATION |
| 4556 | SV3-WLS-MTW-ME0748 | WASTE HOLDUP TANK B INSTALLATION |
| 4557 | SV3-WLS-MTW-ME0749 | WLS MONITOR TANK C INSTALLATION |
| 4558 | SV3-WLS-MTW-ME0750 | WLS CHEMICAL WASTE TANK INSTALLATION |
| 4559 | SV3-WLS-PLW-ME0855 | ASME SECTION III FABRICATE AND INSTALL THE LIQUID RADWASTE SYSTEM (WLS) COLLECTED DRAIN LINE (WLS-PL-L063) TO CONTAINMEN |
| 4560 | SV3-WRS-P0W-ME2492 | FABRICATION AND INSTALLATION OF LARGE BORE WRS PIPING (ISOMETRIC SV3-WRS-PLW-65A, -65B, -654) |
| 4561 | SV3-WRS-PHW-ME0774 | INSTALLATION OF LARGE BORE WRS PIPING SUPPORTS: SV3-WRS-PH-12R4039, 12R4038) |
| 4562 | SV3-WRS-PHW-ME0775 | INSTALLATION OF LARGE BORE WRS PIPING SUPPORTS: SV3-WRS-PH-12R0058, 12R0053) |
| 4563 | SV3-WRS-PLW-ME0944 | WELDING OF WRS PIPING DRAIN HUBS (CA20 SCOPE) (DRAINS FOUND ON ISOMETRIC SV3-WRS-PLW-59R, 654, 65B, 652, 650, AND 56G) |
| 4564 | SV4-1230-SSW-850000 | AUXILIARY BUILDING STRUCTURAL STEEL FROM ELEV 82'-6" UP TO 100'-0" AREA 5 & 6 |
| 4565 | SV3-SFS-P0W-ME4355 | INSTALLATION OF LARGE BORE SFS PIPING ISOMETRICS SV3-SFS-PLW-53N, 53P, 53Y, 53Z |
| 4566 | SV3-WLS-PHW-ME1040 | FABRICATION/INSTALLATION OF PIPE SUPPORTS FOR ISOMETRIC DRAWING WLS-PLW-061 |
| 4567 | SV4-1208-C0W-850004 | CYLINDRICAL WALL RC04 |
| 4568 | SV3-2041-SHW-861948 | INSTALLATION OF WELDED CABLE TRAY SUPPORTS IN TURBINE BUILDING (ELEV 120'6" AREA 1) |
| 4569 | SV3-CVS-PHW-ME4774 | INSTALLATION OF ANNEX CVS PIPING SUPPORTS FOR WP (SV3-CVS-P0W-ME4773) |
| 4570 | SV3-CVS-P0W-ME4773 | FABRICATE AND INSTALL CVS PIPING INCLUDING ISOMETRIC: SV3-CVS-PLW-641,650,680 & 694 |
| 4571 | SV3-PXS-PHW-800074 | INSTALL ASME III SUPPORT SV3-PXS-PH-11R0128 FROM ISO SV3-PXS-PLW-02X |
| 4572 | SV4-KB23-KBW-863105 | INSTALLATION OF KB23 |
| 4573 | SV4-CDS-P0W-863008 | INSTALL CDS PIPING IN UNIT 4 TURBINE BUILDING |
| 4574 | SV4-WLS-THW-863432 | HYDROSTATIC TESTING OF WLS PIPING ON MODULE KB20 |
| 4575 | SV3-WWS-P0W-863012 | Install Large Bore WWS Piping |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 4576 | SV4-ME04-MEW-863331 | INSTALL TB 4 MSR MOISTURE SEPARATOR REHEATER SV4-MSS-ME-01B |
| 4577 | SV4-4002-SSW-863240 | Unit 4 Annex Building Area 2 Stair Tower S04 Girts and Tie-Rods |
| 4578 | SV3-RNS-PHW-800004 | Install large bore pipe supports per SV3-RNS-PLW-17F |
| 4579 | SV4-DWS-THW-861309 | Hydrostatic Testing of WGS Piping on Module R161 |
| 4580 | SV4-ME03-MEW-863437 | Installation of Deaerator SV4-CDS-ME-05 |
| 4581 | SV4-WGS-THW-861312 | Hydrostatic Testing of WGS Piping on Module R161 |
| 4582 | SV4-VWS-THW-861311 | Hydrostatic Testing of VWS Piping on Module R161 |
| 4583 | SV4-PGS-THW-861310 | Hydrostatic Testing of PGS Piping on Module R161 |
| 4584 | SV4-CCS-THW-861308 | Hydrostatic Testing of CCS Piping on Module R161 |
| 4585 | SV3-CA20-C0W-850010 | U3 CA20 FLOOR SUBMODULES 45 AND 46 CONCRETE PLACEMENT AT ELEV 92'-6" |
| 4586 | SV3-4032-SHW-862717 | FABRICATE AND INSTALL CABLE TRAY SUPPORTS, ANNEX BLDG. AREA 2, ELEV. 100', BETWEEN COLUMN LINES 6/7.1 & F/G. |
| 4587 | SV3-4032-SHW-862718 | FABRICATE AND INSTALL CABLE TRAY SUPPORTS ANNEX BLDG AREA 2 ELEV 100' BETWEEN COLUMN LINES 4.1/6 & E/F |
| 4588 | SV4-FPS-P0W-860334 | Fabricate/Install Fire Protection Piping in Unit 4 Turbine Building |
| 4589 | SV3-4031-ERW-863443 | INSTALLATION OF ALL UNSCHEDULED CONDUIT TO INCLUDE BOXES & RECEPTACLES FOR POWER IN ANNEX BLDG AREA 1 ELEV 100'-0" |
| 4590 | SV4-MS60-MSW-861738 | Installation of ASS Electrolyte Feed Tank )ASS-MT-06) and Auxiliary Steam Separator (ASS-MT-08) |
| 4591 | SV3-2036-SHW-861528 | ELECTRICAL CABLE TRAY (WELDED) SUPPORT FABRICATION AND INSTALLATION IN THE UNIT 3 TURBINE BULDING ELEV 100'0" AREA 6 |
| 4592 | SV4-0000-C0W-863509 | UNIT 4 TRANSFORMER EXCITER PAD |
| 4593 | SV3-CCS-PHW-862865 | INSTALLATION OF CCS PIPE SUPPORTS IN ANNEX 3 |
| 4594 | SV3-VWS-PLW-10AU-FP1088 | FABRICATION OF PIPE SPOOLS SV3-VWS-PLW-10AU-1 THRU 5 |
| 4595 | SV4-KB23-KBW-863299 | COMPLETE MODULE KB23 FABRICATION |
| 4596 | SV4-2070-EGW-863325 | GROUNDING INSTALLATION IN THE UNIT 4 TURBINE BUILDING FROM ABOVE THE 170' ELEVATION TO THE 254' ELEVATION ROOF. |
| 4597 | SV4-WWS-THW-863430 | PRESSURE TESTING OF WWS PIPING ON MODULE KB10 |
| 4598 | SV3-PWS-P0W-861752 | INSTALLATION OF PWS PIPING IN ANNEX 3 AREA 1 (ISO'S SV3-PWS-PLW-154, 171, 172, 447, 456, 461 & 966) |
| 4599 | SV3-FPS-P0W-862829 | INSTALLATION OF FPS PIPING IN ANNEX 3 |
| 4600 | SV3-1215-ERW-EL3684 | FABRICATE AND INSTALL FIELD ROUTED TYPICAL CONDUIT SUPPORT C14 FOR AUX BUILDING (AREAS 5 & 6) EL 66'-6" TO 82'-6" |
| 4601 | SV3-KU20-KUW-800002 | Auxillary Building- Staging of Filter Vessel Shield Box KU20CV4 |
| 4602 | SV3-1131-SSW-800000 | IRWST TOWER INSTALLATION @ ELEVATION 103'-1 1/2" |

## Exhibit V – Legacy, WIP, and Completed Work Packages

| Table 3. In-Progress Work Packages (as of October 17, 2017) | | |
|---|---|---|
| 4603 | SV3-2043-SHW-861599 | ELECTRICAL CABLE TRAY TRAPEZE SUPPORTS FABRICATION AND INSTALLATION IN UNIT 3 TURBINE BUILDING, ELEVATION 120'6", AREA 3 |
| 4604 | SV3-2051-SHW-862676 | ELECTRICAL CABLE TRAY WELDED SUPPORT FABRICATION AND INSTALLATION IN THE UNIT 3 TUBRING BUILDING ELEVATION 141'-3" AREA 1 |
| 4605 | SV3-2051-SHW-862678 | ELECTRICAL CABLE TRAY WELDED SUPPORT FABRICATION AND INSTALLATION IN THE UNIT 3 TUBRINE BUILDING ELEVATION 141'-3" AREA 1 |
| 4606 | SV3-PWS-PHW-861755 | INSTALL OF PWS PIPE SUPPORTS IN ANNEX 3 (AREA 1 ISO'S SV3-PWS-PLW-154, 171, 172, 447, 456, 461 & 966) |
| 4607 | SV4-0000-C0W-863510 | UNIT 4 TRANSFORMER PEDESTAL PLACEMENT 14, 16, & 18 |
| 4608 | SV4-CA33-S5W-863153 | CA33 SEAM WELDS |
| 4609 | SV3-VWS-PHW-ME2797 | INSTALLATION OF VWS SUPPORTS FOR ISOMETRIC SV3-VWS-PLW-10Q. |
| 4610 | SV3-CAS-PHW-862827 | INSTALLATION OF ANNEX BLDG CAS PIPE SUPPORTS (ISO SV3-CAS-PLW-20S, 25S, 25U, 25V, 202, 203, 205, 211, 217, 224, 225, 227, & 229) |
| 4611 | SV4-CDS-P0W-860324 | INSTALLATION AND FABRICATION OF CONDENSATE SYSTEM (CDS) PIPING |
| 4612 | SV3-VXS-PHW-862459 | INSTALLATION OF VXS PIPE SUPPORTS IN ANNEX 3 |
| 4613 | SV3-CVS-P0W-800001 | Install ASME III SB Piping for ISO SV3-CVS-PLW-511 |
| 4614 | SV3-RNS-PHW-800005 | Install Large Bore Pipe Supports per Isometric SV3-RNS-PLW-090 |

**Exhibit 21(a)**

**Subsidiaries of the Registrant [(1)]**

| Name of Company | Jurisdiction of Organization |
|---|---|
| **The Southern Company** | Delaware |
| **Alabama Power Company** | Alabama |
| Alabama Power Capital Trust V | Delaware |
| Alabama Property Company | Alabama |
| Southern Electric Generating Company | Alabama |
| **Georgia Power Company** | Georgia |
| Piedmont-Forrest Corporation | Georgia |
| Southern Electric Generating Company | Alabama |
| **Gulf Power Company** | Florida |
| **Mississippi Power Company** | Mississippi |
| **Southern Power Company** | Delaware |
| Mankato Energy Center, LLC | Delaware |
| Mankato Energy Center II, LLC | Delaware |
| Nacogdoches Power, LLC | Delaware |
| RE Roserock Holdings LLC (2) | Delaware |
| RE Roserock LLC | Delaware |
| Southern Company – Florida LLC | Delaware |
| Southern Company – Oleander LLC | Delaware |
| SP Oleander I, LLC | Delaware |
| SP Oleander II, LLC | Delaware |
| Oleander Power Project, LP (3) | Florida |
| Southern Renewable Energy, Inc. | Delaware |
| Grant Plains Wind, LLC | Delaware |
| Grant Wind, LLC | Delaware |
| Grant County Interconnect, LLC (4) | Delaware |
| Kay Wind, LLC | Delaware |
| Passadumkeag Windpark, LLC | Delaware |
| Salt Fork Wind, LLC | Delaware |
| SP Solar GP, Inc. | Delaware |
| SP Solar Holdings I, LP (5) | Delaware |
| BNB Lamesa Solar LLC | Delaware |
| East Pecos Solar, LLC | Delaware |
| SP Solar Farms, LLC | Delaware |
| Adobe Solar, LLC | Delaware |
| Apex Nevada Solar, LLC | Delaware |
| Calipatria, LLC | Delaware |
| Campo Verde Solar, LLC | Delaware |
| Granville Solar, LLC | Delaware |
| Macho Springs Solar, LLC | Delaware |
| Macho Springs Solar 2, LLC | Delaware |

| | |
|---|---|
| Morelos Solar, LLC | Delaware |
| Rutherford Farm, LLC | North Carolina |
| SP Cimarron I, LLC | Delaware |
| SP Cimarron Capital, LLC | Delaware |
| Spectrum Nevada Solar, LLC | Delaware |
| Tyler Bluff Wind Project, LLC | Delaware |
| Southern Renewable Partnerships, LLC | Delaware |
| Desert Stateline Holdings, LLC (6) | Delaware |
| Desert Stateline, LLC | Delaware |
| Lost Hills Blackwell Holdings, LLC (7) | Delaware |
| Lost Hills Solar Holdco, LLC | Delaware |
| Lost Hills Solar, LLC | Delaware |
| Blackwell Solar Holdings, LLC | Delaware |
| Blackwell Solar, LLC | Delaware |
| NS Solar Holdings, LLC (7) | Delaware |
| North Star Solar, LLC | Delaware |
| SG2 Holdings, LLC (7) | Delaware |
| SG2 Imperial Valley LLC | Delaware |
| BSP Holding Company, LLC (7) | Delaware |
| Boulder Solar Power Parent, LLC | Delaware |
| Boulder Solar Power, LLC | Delaware |
| Parrey Holding Company, LLC (7) | Delaware |
| Parrey Parent, LLC | Delaware |
| Parrey, LLC | Delaware |
| RE Silverlake Holdings LLC (7) | Delaware |
| RE Garland Holdings LLC | Delaware |
| RE Garland LLC | Delaware |
| RE Garland A LLC | Delaware |
| RE Tranquility Holdings LLC (7) | Delaware |
| RE Tranquility LLC | Delaware |
| RE Tranquility BAAH LLC | Delaware |
| SP Butler Solar Farm, LLC | Delaware |
| SP Butler Solar, LLC | Delaware |
| SP Decatur County Solar, LLC | Delaware |
| SP Decatur Parkway Solar, LLC | Delaware |
| SP Pawpaw Solar, LLC | Delaware |
| SP Sandhills Solar, LLC | Delaware |
| SP TEP Class B Holdings I, Inc. | Delaware |
| SP Gaskell West 1 Class B Holdings, LLC | Delaware |
| SP Gaskell West 1 Holdings, LLC | Delaware |
| SP Wind Development Holdings, LLC | Delaware |
| SP TEP Formations, Inc. | Delaware |
| SP Cactus Flats Class B Holdings, LLC | Delaware |
| Cactus Flats Holdings, LLC | Delaware |
| SP Cactus Flats Wind Energy, LLC | Delaware |
| SP Wind Holdings, LLC | Delaware |

| | |
|---|---|
| Bethel Wind Farm Class B Holdings LLC | Delaware |
| Bethel Wind Farm Holdings LLC | Delaware |
| Bethel Wind Farm LLC | Delaware |
| SPR Development Holdings, LLC (8) | Delaware |
| WWH, LLC (9) | Delaware |
| Wake Wind Class B Holdings LLC | Delaware |
| Wake Wind Holdings LLC | Delaware |
| Wake Wind Energy LLC | Delaware |
| **Southern Company Gas** | Georgia |
| Southern Company Gas Capital Corporation | Nevada |
| Southern Company Gas Investments Inc. | Georgia |
| Sequent LLC | Georgia |
| Atlanta Gas Light Company | Georgia |
| Georgia Natural Gas Company | Georgia |
| SouthStar Energy Services LLC | Delaware |
| NUI Corporation | New Jersey |
| Pivotal Utility Holdings Inc. (10) | New Jersey |
| Ottawa Acquisition LLC | Illinois |
| Northern Illinois Gas Company (11) | Illinois |
| Southern Company Gas Investments, Inc. | Georgia |
| Southern Company Gas Pipeline Holdings LLC | Georgia |
| Evergreen Enterprise Holdings LLC | Georgia |

(1) This information is as of December 31, 2017. In addition, this list omits certain subsidiaries pursuant to paragraph (b)(21)(ii) of Regulation S-K, Item 601.
(2) Southern Power Company owns 100% of the class A membership interests and is entitled to 51% of all cash distributions.
(3) SP Oleander II LLC owns 99% and SP Oleander I LLC owns 1%.
(4) Grant Wind, LLC owns 90.1% and Grant Plains Wind, LLC owns 9.1%.
(5) Southern Renewable Energy, Inc. owns 99% and SP Solar GP, Inc. owns 1%.
(6) Southern Renewable Partnerships, LLC owns 100% of the class A membership interests and is entitled to 66% of all cash distributions.
(7) Southern Renewable Partnerships, LLC owns 100% of the class A membership interests and is entitled to 51% of all cash distributions.
(8) SP Wind Holdings, LLC owns 51%.
(9) SP Wind Holdings, LLC owns 90.1%.
(10) Includes operations of three natural gas utilities: Elizabethtown Gas (New Jersey), Florida City Gas (Florida), and Elkton Gas (Maryland).
(11) Doing business as Nicor Gas Company.

Exhibit 23(a)1

**CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

We consent to the incorporation by reference in Registration Statement Nos. 2-78617, 33-54415, 33-58371, 33-60427, 333-44127, 333-118061, 333-166709, 333-174707, 333-204618 , 333-208173 , and 333-212783 on Form S-8 and Registration Statement Nos. 333-202410 and 333-202413 on Form S-3 of our reports dated February 20, 2018, relating to the consolidated financial statements and consolidated financial statement schedule of The Southern Company and Subsidiary Companies, and the effectiveness of The Southern Company and Subsidiary Companies' internal control over financial reporting, appearing in this Annual Report on Form 10-K of The Southern Company for the year ended December 31, 2017.

/s/Deloitte & Touche LLP

Atlanta, Georgia
February 20, 2018

**CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

We consent to the incorporation by reference in Registration Statement No. 333-216229 on Form S-3 of our reports dated February 20, 2018, relating to the financial statements and financial statement schedule of Alabama Power Company, appearing in this Annual Report on Form 10-K of Alabama Power Company for the year ended December 31, 2017.

/s/Deloitte & Touche LLP

Birmingham, Alabama
February 20, 2018

**CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

We consent to the incorporation by reference in Registration Statement No. 333-209779 on Form S-3 of our reports dated February 20, 2018, relating to the financial statements and financial statement schedule of Georgia Power Company, appearing in this Annual Report on Form 10-K of Georgia Power Company for the year ended December 31, 2017.

/s/Deloitte & Touche LLP

Atlanta, Georgia
February 20, 2018

Exhibit 23(d)1

**CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

We consent to the incorporation by reference in Registration Statement No. 333-211416 on Form S-3 of our reports dated February 20, 2018, relating to the financial statements and financial statement schedule of Gulf Power Company, appearing in this Annual Report on Form 10-K of Gulf Power Company for the year ended December 31, 2017.

/s/Deloitte & Touche LLP

Atlanta, Georgia
February 20, 2018

**CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

We consent to the incorporation by reference in Registration Statement No. 333-219651 on Form S-3 of our reports dated February 20, 2018, relating to the financial statements and financial statement schedule of Mississippi Power Company, appearing in this Annual Report on Form 10-K of Mississippi Power Company for the year ended December 31, 2017.

/s/Deloitte & Touche LLP

Atlanta, Georgia
February 20, 2018

Exhibit 23(f)1

**CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

We consent to the incorporation by reference in Registration Statement No. 333-213264 on Form S-3 of our report dated February 20, 2018, relating to the consolidated financial statements of Southern Power Company and Subsidiary Companies, appearing in this Annual Report on Form 10-K of Southern Power Company for the year ended December 31, 2017.

/s/Deloitte & Touche LLP

Atlanta, Georgia
February 20, 2018

Exhibit 23(g)1

**CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

We consent to the incorporation by reference in Registration Statement No. 333-212328 on Form S-3 and Registration Statement Nos. 333-26963 and 333-154965 on Form S-8 of our reports dated February 20, 2018, relating to the consolidated financial statements and financial statement schedule of Southern Company Gas and Subsidiary Companies, appearing in this Annual Report on Form 10-K of Southern Company Gas for the year ended December 31, 2017.

/s/Deloitte & Touche LLP

Atlanta, Georgia
February 20, 2018

Exhibit 23(g)2

**CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-212328) and Form S-8 (Nos. 333-26963 and 333-154965) of Southern Company Gas (formerly AGL Resources Inc.) of our report dated February 11, 2016 relating to the financial statements and the financial statement schedule of Southern Company Gas, which appears in this Annual Report on Form 10-K of Southern Company Gas.

/s/ PricewaterhouseCoopers LLP
Atlanta, Georgia
February 20, 2018

Exhibit 23(g)3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-212328) and on Form S-8 (Nos. 333-26963 and 333-154965) of Southern Company Gas of our report dated February 14, 2018 relating to the financial statements of Southern Natural Gas Company, L.L.C., which appears in this Form 10-K of Southern Company Gas.

*/s/ PricewaterhouseCoopers LLP*

Houston, Texas

February 14, 2018

Exhibit 24(a)

February 12, 2018

Myra C. Bierria and Melissa K. Caen

Ms. Bierria and Ms. Caen:

The Southern Company (the "Company") proposes to file or join in the filing of reports under the Securities Exchange Act of 1934, as amended, with the Securities and Exchange Commission with respect to the following: (1) the Company's Annual Report on Form 10-K for the year ended December 31, 2017 and (2) the Company's Quarterly Reports on Form 10-Q during 2018.

The Company and the undersigned directors and officers of the Company, individually as a director and/or as an officer of the Company, hereby make, constitute and appoint each of you our true and lawful Attorney for each of us and in each of our names, places and steads to sign and cause to be filed with the Securities and Exchange Commission in connection with the foregoing said Annual Report on Form 10-K, said Quarterly Reports on Form 10-Q and any necessary or appropriate amendment or amendments to any such reports, to be accompanied in each case by any necessary or appropriate exhibits or schedules thereto.

Yours very truly,

THE SOUTHERN COMPANY

By /s/Thomas A. Fanning

Thomas A. Fanning
Chairman, President and
Chief Executive Officer

/s/Juanita Powell Baranco
Juanita Powell Baranco

/s/Jon A. Boscia
Jon A. Boscia

/s/Henry A. Clark III
Henry A. Clark III

/s/Thomas A. Fanning
Thomas A. Fanning

/s/David J. Grain
David J. Grain

/s/Veronica M. Hagen
Veronica M. Hagen

/s/Warren A. Hood, Jr.
Warren A. Hood, Jr.

/s/Linda P. Hudson
Linda P. Hudson

/s/Donald M. James
Donald M. James

/s/John D. Johns
John D. Johns

/s/Dale E. Klein
Dale E. Klein

/s/William G. Smith, Jr.
William G. Smith, Jr.

/s/Steven R. Specker
Steven R. Specker

/s/Larry D. Thompson
Larry D. Thompson

/s/E. Jenner Wood III
E. Jenner Wood III

/s/Art P. Beattie
Art P. Beattie

/s/Ann P. Daiss
Ann P. Daiss

Extract from minutes of meeting of the board of directors of The Southern Company.

- - - - - - - - - -

RESOLVED: That for the purpose of signing the reports under the Securities Exchange Act of 1934 to be filed with the Securities and Exchange Commission with respect to the filing of the Company's Annual Report on Form 10-K for the year ended December 31, 2017 and its 2018 Quarterly Reports on Form 10-Q, and any necessary or appropriate amendment or amendments to any such reports, the Company, the members of its Board of Directors and its officers be and hereby are authorized to give their several powers of attorney to Myra C. Bierria and Melissa K. Caen.

- - - - - - - - - -

The undersigned officer of The Southern Company does hereby certify that the foregoing is a true and correct copy of a resolution duly and regularly adopted at a meeting of the board of directors of The Southern Company, duly held on February 12, 2018, at which a quorum was in attendance and voting throughout, and that said resolution has not since been rescinded but is still in full force and effect.

Dated: February 20, 2018

THE SOUTHERN COMPANY

By /s/Melissa K. Caen

Melissa K. Caen
Assistant Secretary

**Mark A. Crosswhite**
Chairman, President and
Chief Executive Officer

600 North 18th Street
Post Office Box 2641
Birmingham, Alabama 35291-0001

Tel 205.257.1000
Fax 205.257.5100

January 26, 2018

Art P. Beattie
30 Ivan Allen Jr. Blvd., N.W.
Atlanta, Georgia 30308

Melissa K. Caen
30 Ivan Allen Jr. Blvd., N.W.
Atlanta, Georgia 30308

Dear Mr. Beattie and Ms. Caen:

Alabama Power Company (the "Company") proposes to file or join in the filing of reports under the Securities Exchange Act of 1934, as amended, with the Securities and Exchange Commission with respect to the following: (1) the Company's Annual Report on Form 10-K for the year ended December 31, 2017 and (2) the Company's Quarterly Reports on Form 10-Q during 2018.

The Company and the undersigned directors and officers of the Company, individually as a director and/or as an officer of the Company, hereby make, constitute and appoint each of you our true and lawful Attorney for each of us and in each of our names, places and steads to sign and cause to be filed with the Securities and Exchange Commission in connection with the foregoing said Annual Report on Form 10-K, said Quarterly Reports on Form 10-Q and any necessary or appropriate amendment or amendments to any such reports, to be accompanied in each case by any necessary or appropriate exhibits or schedules thereto.

Yours very truly,

ALABAMA POWER COMPANY

By /s/Mark A. Crosswhite
Mark A. Crosswhite
Chairman, President and Chief Executive Officer

/s/Whit Armstrong
Whit Armstrong

/s/Robert D. Powers
Robert D. Powers

/s/David J. Cooper, Sr.
David J. Cooper, Sr.

/s/Catherine J. Randall
Catherine J. Randall

/s/Mark A. Crosswhite
Mark A. Crosswhite

/s/C. Dowd Ritter
C. Dowd Ritter

/s/O. B. Grayson Hall, Jr.
O. B. Grayson Hall, Jr.

/s/R. Mitchell Shackleford III
R. Mitchell Shackleford III

/s/Anthony A. Joseph
Anthony A. Joseph

/s/Philip C. Raymond
Philip C. Raymond

/s/Patricia M. King
Patricia M. King

/s/Anita Allcorn-Walker
Anita Allcorn-Walker

/s/James K. Lowder
James K. Lowder

Extract from minutes of meeting of the board of directors of Alabama Power Company.

- - - - - - - - - -

RESOLVED: That for the purpose of signing the reports under the Securities Exchange Act of 1934 to be filed with the Securities and Exchange Commission with respect to the filing of this Company's Annual Report on Form 10-K for the year ended December 31, 2017 and its 2018 Quarterly Reports on Form 10-Q, and any necessary or appropriate amendment or amendments to any such reports, this Company, the members of its board of directors and its officers are authorized to give their several powers of attorney to Art P. Beattie and Melissa K. Caen.

- - - - - - - - - -

The undersigned officer of Alabama Power Company does hereby certify that the foregoing is a true and correct copy of a resolution duly and regularly adopted at a meeting of the board of directors of Alabama Power Company, duly held on January 26, 2018, at which a quorum was in attendance and voting throughout, and that said resolution has not since been rescinded but is still in full force and effect.

Dated: February 20, 2018

ALABAMA POWER COMPANY

By /s/Melissa K. Caen

Melissa K. Caen
Assistant Secretary

Exhibit 24(c)

February 19, 2018

Xia Liu, David P. Poroch, Art P. Beattie and Melissa K. Caen

Ladies and Gentlemen:

Georgia Power Company (the "Company") proposes to file or join in the filing of reports under the Securities Exchange Act of 1934, as amended, with the Securities and Exchange Commission with respect to the following: (1) the Company's Annual Report on Form 10-K for the year ended December 31, 2017 and (2) the Company's Quarterly Reports on Form 10-Q during 2018.

The Company and the undersigned directors and officers of the Company, individually as a director and/or as an officer of the Company, hereby make, constitute and appoint each of you our true and lawful Attorney for each of us and in each of our names, places and steads to sign and cause to be filed with the Securities and Exchange Commission in connection with the foregoing said Annual Report on Form 10-K, said Quarterly Reports on Form 10-Q and any necessary or appropriate amendment or amendments to any such reports, to be accompanied in each case by any necessary or appropriate exhibits or schedules thereto.

Yours very truly,

GEORGIA POWER COMPANY

By /s/W. Paul Bowers

W. Paul Bowers
Chairman, President and Chief Executive Officer

/s/W. Paul Bowers
W. Paul Bowers

/s/Jimmy C. Tallent
Jimmy C. Tallent

/s/Mark L. Burns
Mark L. Burns

/s/Charles K. Tarbutton
Charles K. Tarbutton

/s/Shantella E. Cooper
Shantella E. Cooper

/s/Beverly Daniel Tatum
Beverly Daniel Tatum

/s/Lawrence L. Gellerstedt, III
Lawrence L. Gellerstedt, III

/s/Clyde C. Tuggle
Clyde C. Tuggle

/s/Stephen S. Green
Stephen S. Green

/s/Xia Liu
Xia Liu

/s/Douglas J. Hertz
Douglas J. Hertz

/s/David P. Poroch
David P. Poroch

/s/Kessel D. Stelling, Jr.
Kessel D. Stelling, Jr.

Extract from unanimous written consent of the board of directors of Georgia Power Company.

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RESOLVED: That for the purpose of signing the reports under the Securities Exchange Act of 1934 to be filed with the Securities and Exchange Commission with respect to the filing of this Company's Annual Report on Form 10-K for the year ended December 31, 2017 and its 2018 Quarterly Reports on Form 10-Q, and any necessary or appropriate amendment or amendments to any such reports, the Company, the members of its board of directors and its officers are authorized to give their several powers of attorney to Xia Liu, David P. Poroch, Art P. Beattie and Melissa K. Caen.

- - - - - - - - -

The undersigned officer of Georgia Power Company does hereby certify that the foregoing is a true and correct copy of a resolution duly and regularly adopted by unanimous written consent dated February 19, 2018 of the board of directors of Georgia Power Company, and that said resolution has not since been rescinded but is still in full force and effect.

Dated: February 20, 2018

GEORGIA POWER COMPANY

By /s/Melissa K. Caen

Melissa K. Caen
Assistant Secretary

Exhibit 24(d)

October 16, 2017

| | |
|---|---|
| Mr. Art P. Beattie<br>The Southern Company<br>30 Ivan Allen Jr. Blvd., NW<br>Atlanta, GA 30308 | Ms. Melissa K. Caen<br>Southern Company Services, Inc.<br>30 Ivan Allen Jr. Blvd., NW<br>Atlanta, GA 30308 |

Dear Mr. Beattie and Ms. Caen:

Gulf Power Company (the "Company") proposes to file or join in the filing of reports under the Securities Exchange Act of 1934, as amended, with the Securities and Exchange Commission with respect to the following: (1) the Company's Annual Report on Form 10-K for the year ended December 31, 2017 and (2) the Company's Quarterly Reports on Form 10-Q during 2018.

The Company and the undersigned directors and officers of the Company, individually as a director and/or as an officer of the Company, hereby make, constitute and appoint each of you our true and lawful Attorney for each of us and in each of our names, places and steads to sign and cause to be filed with the Securities and Exchange Commission in connection with the foregoing said Annual Report on Form 10-K, said Quarterly Reports on Form 10-Q and any necessary or appropriate amendment or amendments to any such reports, to be accompanied in each case by any necessary or appropriate exhibits or schedules thereto.

Yours very truly,

GULF POWER COMPANY

By /s/S. W. Connally, Jr.
S. W. Connally, Jr.
Chairman, President and Chief Executive Officer

/s/Allan G. Bense
Allan G. Bense

/s/J. Mort O'Sullivan, III
J. Mort O'Sullivan, III

/s/Deborah H. Calder
Deborah H. Calder

/s/Michael T. Rehwinkel
Michael T. Rehwinkel

/s/S. W. Connally, Jr.
S. W. Connally, Jr.

/s/Winston E. Scott
Winston E. Scott

/s/William C. Cramer, Jr.
William C. Cramer, Jr.

/s/Robin B. Boren
Robin B. Boren

/s/Julian B. MacQueen
Julian B. MacQueen

/s/Jeff A. Stone
Jeff A. Stone

/s/Paul D. Trippe
Paul D. Trippe

Extract from minutes of meeting of the board of directors of Gulf Power Company.

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RESOLVED, That for the purpose of signing the reports under the Securities Exchange Act of 1934, as amended, to be filed with the Securities and Exchange Commission with respect to the filing of the Company's Annual Report on Form 10-K for the year ended December 31, 2017 and its 2018 Quarterly Reports on Form 10-Q, and any necessary or appropriate amendment or amendments to any such reports, the Company, the members of its board of directors and its officers are authorized to give their several powers of attorney to Art P. Beattie and Melissa K. Caen.

- - - - - - - - - -

The undersigned officer of Gulf Power Company does hereby certify that the foregoing is a true and correct copy of a resolution duly and regularly adopted at a meeting of the board of directors of Gulf Power Company, duly held on October 16, 2017, at which a quorum was in attendance and voting throughout, and that said resolution has not since been rescinded but is still in full force and effect.

Dated: February 20, 2018

GULF POWER COMPANY

By /s/Melissa K. Caen

Melissa K. Caen
Assistant Secretary

Exhibit 24(e)

October 16, 2017


Mr. Art P. Beattie
The Southern Company
30 Ivan Allen Jr. Blvd., NW
Atlanta, GA 30308

Ms. Melissa K. Caen
Southern Company Services, Inc.
30 Ivan Allen Jr. Blvd., NW
Atlanta, GA 30308


Mr. Beattie and Ms. Caen:

Mississippi Power Company (the "Company") proposes to file or join in the filing of reports under the Securities Exchange Act of 1934, as amended, with the Securities and Exchange Commission with respect to the following: (1) the Company's Annual Report on Form 10-K for the year ended December 31, 2017 and (2) the Company's Quarterly Reports on Form 10-Q during 2018.

The Company and the undersigned directors and officers of the Company, individually as a director and/or as an officer of the Company, hereby make, constitute and appoint each of you our true and lawful Attorney for each of us and in each of our names, places and steads to sign and cause to be filed with the Securities and Exchange Commission in connection with the foregoing said Annual Report on Form 10-K, said Quarterly Reports on Form 10-Q and any necessary or appropriate amendment or amendments to any such reports, to be accompanied in each case by any necessary or appropriate exhibits or schedules thereto.

Yours very truly,

MISSISSIPPI POWER COMPANY

By /s/Anthony L. Wilson

Anthony L. Wilson
Chairman, President and Chief
Executive Officer

/s/Carl J. Chaney
Carl J. Chaney

/s/M. L. Waters
M. L. Waters

/s/L. Royce Cumbest
L. Royce Cumbest

/s/Anthony L. Wilson
Anthony L. Wilson

/s/Mark E. Keenum
Mark E. Keenum

/s/Moses H. Feagin
Moses H. Feagin

/s/Christine L. Pickering
Christine L. Pickering

/s/Cynthia F. Shaw
Cynthia F. Shaw

/s/Philip J. Terrell
Philip J. Terrell

/s/Vicki L. Pierce
Vicki L. Pierce

Extract from minutes of meeting of the board of directors of Mississippi Power Company.

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RESOLVED, That for the purpose of signing the reports under the Securities Exchange Act of 1934, as amended, to be filed with the Securities and Exchange Commission with respect to the filing of the Company's Annual Report on Form 10-K for the year ended December 31, 2017 and its 2018 Quarterly Reports on Form 10-Q, and any necessary or appropriate amendment or amendments to any such reports, the Company, the members of its board of directors and its officers are authorized to give their several powers of attorney to Art P. Beattie and Melissa K. Caen.

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The undersigned officer of Mississippi Power Company does hereby certify that the foregoing is a true and correct copy of a resolution duly and regularly adopted at a meeting of the board of directors of Mississippi Power Company, duly held on October 16, 2017, at which a quorum was in attendance and voting throughout, and that said resolution has not since been rescinded but is still in full force and effect.

Dated: February 20, 2018

MISSISSIPPI POWER COMPANY

By /s/Melissa K. Caen

Melissa K. Caen
Assistant Secretary

Exhibit 24(f)

November 17, 2017

Mr. Elliott L. Spencer
Southern Power Company
30 Ivan Allen Jr. Blvd, NW
Atlanta, GA 30308

Ms. Melissa K. Caen
Southern Company Services, Inc.
30 Ivan Allen Jr. Blvd, NW
Atlanta, GA 30308

Mr. Spencer and Ms. Caen:

Southern Power Company (the "Company") proposes to file or join in the filing of reports under the Securities Exchange Act of 1934, as amended, with the Securities and Exchange Commission with respect to the following: (1) the Company's Annual Report on Form 10-K for the year ended December 31, 2017 and (2) the Company's Quarterly Reports on Form 10-Q during 2018.

The Company and the undersigned directors and officers of the Company, individually as a director and/or as an officer of the Company, hereby make, constitute and appoint each of you our true and lawful Attorney for each of us and in each of our names, places and steads to sign and cause to be filed with the Securities and Exchange Commission in connection with the foregoing said Annual Report on Form 10-K, said Quarterly Reports on Form 10-Q and any necessary or appropriate amendment or amendments to any such reports, to be accompanied in each case by any necessary or appropriate exhibits or schedules thereto.

Yours very truly,

SOUTHERN POWER COMPANY

By /s/Joseph A. Miller

Joseph A. Miller
Chairman, President and
Chief Executive Officer

/s/Art P. Beattie
Art P. Beattie

/s/Joseph A. Miller
Joseph A. Miller

/s/Thomas A. Fanning
Thomas A. Fanning

/s/Christopher C. Womack
Christopher C. Womack

/s/Kimberly S. Greene
Kimberly S. Greene

/s/William C. Grantham
William C. Grantham

/s/James Y. Kerr, II
James Y. Kerr, II

/s/Elliott L. Spencer
Elliott L. Spencer

/s/Mark S. Lantrip
Mark S. Lantrip

Extract from minutes of meeting of the board of directors of Southern Power Company.

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RESOLVED: That for the purpose of signing the reports under the Securities Exchange Act of 1934 to be filed with the Securities and Exchange Commission with respect to the filing of the Company's Annual Report on Form 10-K for the year ended December 31, 2017 and its 2018 Quarterly Reports on Form 10-Q, and any necessary or appropriate amendment or amendments to any such reports, the Company, the members of its board of directors and its officers are authorized to give their several powers of attorney to Elliott L. Spencer and Melissa K. Caen.

- - - - - - - - - -

The undersigned officer of Southern Power Company does hereby certify that the foregoing is a true and correct copy of a resolution duly and regularly adopted at a meeting of the board of directors of Southern Power Company, duly held on November 17, 2017, at which a quorum was in attendance and voting throughout, and that said resolution has not since been rescinded but is still in full force and effect.

Dated: February 20, 2018

SOUTHERN POWER COMPANY

By /s/Melissa K. Caen

Melissa K. Caen
Assistant Secretary

Exhibit 24(g)

February 6, 2018

Myra C. Bierria and Melissa K. Caen

Ms. Bierria and Ms. Caen:

Southern Company Gas (the "Company") proposes to file or join in the filing of reports under the Securities Exchange Act of 1934, as amended, with the Securities and Exchange Commission with respect to the following: (1) the Company's Annual Report on Form 10-K for the year ended December 31, 2017 and (2) the Company's Quarterly Reports on Form 10-Q during 2018.

The Company and the undersigned directors and officers of the Company, individually as a director and/or as an officer of the Company, hereby make, constitute and appoint each of you our true and lawful Attorney for each of us and in each of our names, places and steads to sign and cause to be filed with the Securities and Exchange Commission in connection with the foregoing said Annual Report on Form 10-K, said Quarterly Reports on Form 10-Q and any necessary or appropriate amendment or amendments to any such reports, to be accompanied in each case by any necessary or appropriate exhibits or schedules thereto.

Yours very truly,

SOUTHERN COMPANY GAS

By /s/Andrew W. Evans

Andrew W. Evans
Chairman, President and
Chief Executive Officer

/s/Sandra N. Bane
Sandra N. Bane

/s/Kimberly S. Greene
Kimberly S. Greene

/s/Thomas D. Bell, Jr.
Thomas D. Bell, Jr.

/s/John E. Rau
John E. Rau

/s/Charles R. Crisp
Charles R. Crisp

/s/James A. Rubright
James A. Rubright

/s/Andrew W. Evans
Andrew W. Evans

/s/Elizabeth W. Reese
Elizabeth W. Reese

/s/Brenda J. Gaines
Brenda J. Gaines

/s/Grace A. Kolvereid
Grace A. Kolvereid

Extract from minutes of meeting of the board of directors of Southern Company Gas.

- - - - - - - - - -

RESOLVED: That for the purpose of signing the reports under the Securities Exchange Act of 1934 to be filed with the Securities and Exchange Commission with respect to the filing of the Company's Annual Report on Form 10-K for the year ended December 31, 2017 and its 2018 Quarterly Reports on Form 10-Q, and any necessary or appropriate amendment or amendments to any such reports, the Company, the members of its Board of Directors and its officers be and hereby are authorized to give their several powers of attorney to Myra C. Bierria and Melissa K. Caen.

- - - - - - - - - -

The undersigned officer of Southern Company Gas does hereby certify that the foregoing is a true and correct copy of a resolution duly and regularly adopted at a meeting of the board of directors of Southern Company Gas, duly held on February 6, 2018, at which a quorum was in attendance and voting throughout, and that said resolution has not since been rescinded but is still in full force and effect.

Dated: February 20, 2018

SOUTHERN COMPANY GAS

By /s/Melissa K. Caen

Melissa K. Caen
Assistant Secretary

Exhibit 31(a)1

**THE SOUTHERN COMPANY**

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER**

I, Thomas A. Fanning, certify that:

1. I have reviewed this annual report on Form 10-K of The Southern Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2018

/s/Thomas A. Fanning

Thomas A. Fanning
Chairman, President and
Chief Executive Officer

Exhibit 31(a)2

**THE SOUTHERN COMPANY**

**CERTIFICATION OF CHIEF FINANCIAL OFFICER**

I, Art P. Beattie, certify that:

1. I have reviewed this annual report on Form 10-K of The Southern Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2018

/s/Art P. Beattie

Art P. Beattie
Executive Vice President and Chief Financial Officer

Exhibit 31(b)1

**ALABAMA POWER COMPANY**

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER**

I, Mark A. Crosswhite, certify that:

1. I have reviewed this annual report on Form 10-K of Alabama Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2018

/s/Mark A. Crosswhite

Mark A. Crosswhite

Chairman, President and Chief Executive Officer

Exhibit 31(b)2

**ALABAMA POWER COMPANY**

**CERTIFICATION OF CHIEF FINANCIAL OFFICER**

I, Philip C. Raymond, certify that:

1. I have reviewed this annual report on Form 10-K of Alabama Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2018

/s/Philip C. Raymond

Philip C. Raymond
Executive Vice President, Chief Financial Officer
and Treasurer

Exhibit 31(c)1

**GEORGIA POWER COMPANY**

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER**

I, W. Paul Bowers, certify that:

1. I have reviewed this annual report on Form 10-K of Georgia Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2018

/s/W. Paul Bowers

W. Paul Bowers

Chairman, President and Chief Executive Officer

Exhibit 31(c)2

**GEORGIA POWER COMPANY**

**CERTIFICATION OF CHIEF FINANCIAL OFFICER**

I, Xia Liu, certify that:

1. I have reviewed this annual report on Form 10-K of Georgia Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2018

/s/Xia Liu

Xia Liu

Executive Vice President, Chief Financial Officer and Treasurer

Exhibit 31(d)1

## GULF POWER COMPANY

## CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, S. W. Connally, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of Gulf Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2018

/s/S. W. Connally, Jr.

S. W. Connally, Jr.
Chairman, President and Chief Executive Officer

Exhibit 31(d)2

**GULF POWER COMPANY**

**CERTIFICATION OF CHIEF FINANCIAL OFFICER**

I, Robin B. Boren, certify that:

1. I have reviewed this annual report on Form 10-K of Gulf Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2018

/s/Robin B. Boren

Robin B. Boren
Vice President, Chief Financial Officer and
Treasurer

Exhibit 31(e)1

**MISSISSIPPI POWER COMPANY**

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER**

I, Anthony L. Wilson, certify that:

1. I have reviewed this annual report on Form 10-K of Mississippi Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2018

/s/Anthony L. Wilson

Anthony L. Wilson

Chairman, President and
Chief Executive Officer

Exhibit 31(e)2

**MISSISSIPPI POWER COMPANY**

**CERTIFICATION OF CHIEF FINANCIAL OFFICER**

I, Moses H. Feagin, certify that:

1. I have reviewed this annual report on Form 10-K of Mississippi Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2018

/s/Moses H. Feagin

Moses H. Feagin

Vice President, Treasurer and
Chief Financial Officer

Exhibit 31(f)1

**SOUTHERN POWER COMPANY**

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER**

I, Joseph A. Miller, certify that:

1. I have reviewed this annual report on Form 10-K of Southern Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 20, 2018

/s/Joseph A. Miller

Joseph A. Miller

Chairman, President and Chief Executive Officer

Exhibit 31(f)2

**SOUTHERN POWER COMPANY**

**CERTIFICATION OF CHIEF FINANCIAL OFFICER**

I, William C. Grantham, certify that:

1. I have reviewed this annual report on Form 10-K of Southern Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2018

/s/William C. Grantham

William C. Grantham

Senior Vice President, Treasurer and Chief Financial Officer

Exhibit 31(g)1

**SOUTHERN COMPANY GAS**

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER**

I, Andrew W. Evans, certify that:

1. I have reviewed this annual report on Form 10-K of Southern Company Gas;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 20, 2018

/s/Andrew W. Evans

Andrew W. Evans

Chairman, President, and Chief Executive Officer

Exhibit 31(g)2

**SOUTHERN COMPANY GAS**

**CERTIFICATION OF CHIEF FINANCIAL OFFICER**

I, Elizabeth W. Reese, certify that:

1. I have reviewed this annual report on Form 10-K of Southern Company Gas;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2018

/s/Elizabeth W. Reese

Elizabeth W. Reese

Executive Vice President, Chief Financial Officer, and Treasurer

Exhibit 32(a)

**CERTIFICATION**

**18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

In connection with the accompanying Annual Report on Form 10-K of The Southern Company for the year ended December 31, 2017, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Annual Report on Form 10-K of The Southern Company for the year ended December 31, 2017, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of The Southern Company for the year ended December 31, 2017, fairly presents, in all material respects, the financial condition and results of operations of The Southern Company.

/s/Thomas A. Fanning

Thomas A. Fanning
Chairman, President and
Chief Executive Officer

/s/Art P. Beattie

Art P. Beattie
Executive Vice President and
Chief Financial Officer

February 20, 2018

Exhibit 32(b)

**CERTIFICATION**

**18 U.S.C. SECTION 1350**
**AS ADOPTED PURSUANT TO SECTION 906 OF THE**
**SARBANES-OXLEY ACT OF 2002**

In connection with the accompanying Annual Report on Form 10-K of Alabama Power Company for the year ended December 31, 2017, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Annual Report on Form 10-K of Alabama Power Company for the year ended December 31, 2017, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of Alabama Power Company for the year ended December 31, 2017, fairly presents, in all material respects, the financial condition and results of operations of Alabama Power Company.

/s/Mark A. Crosswhite

Mark A. Crosswhite
Chairman, President and Chief Executive Officer

/s/Philip C. Raymond

Philip C. Raymond
Executive Vice President,
Chief Financial Officer and Treasurer

February 20, 2018

Exhibit 32(c)

**CERTIFICATION**

**18 U.S.C. SECTION 1350**
**AS ADOPTED PURSUANT TO SECTION 906 OF THE**
**SARBANES-OXLEY ACT OF 2002**

In connection with the accompanying Annual Report on Form 10-K of Georgia Power Company for the year ended December 31, 2017, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Annual Report on Form 10-K of Georgia Power Company for the year ended December 31, 2017, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of Georgia Power Company for the year ended December 31, 2017, fairly presents, in all material respects, the financial condition and results of operations of Georgia Power Company.

/s/W. Paul Bowers

W. Paul Bowers
Chairman, President and Chief Executive Officer

/s/Xia Liu

Xia Liu
Executive Vice President, Chief Financial Officer and Treasurer

February 20, 2018

Exhibit 32(d)

**CERTIFICATION**

**18 U.S.C. SECTION 1350**
**AS ADOPTED PURSUANT TO SECTION 906 OF THE**
**SARBANES-OXLEY ACT OF 2002**

In connection with the accompanying Annual Report on Form 10-K of Gulf Power Company for the year ended December 31, 2017, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Annual Report on Form 10-K of Gulf Power Company for the year ended December 31, 2017, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of Gulf Power Company for the year ended December 31, 2017, fairly presents, in all material respects, the financial condition and results of operations of Gulf Power Company.

/s/S. W. Connally, Jr.
S. W. Connally, Jr.
Chairman, President and Chief Executive Officer

/s/Robin B. Boren
Robin B. Boren
Vice President, Chief Financial Officer and Treasurer

February 20, 2018

Exhibit 32(e)

**CERTIFICATION**

**18 U.S.C. SECTION 1350**
**AS ADOPTED PURSUANT TO SECTION 906 OF THE**
**SARBANES-OXLEY ACT OF 2002**

In connection with the accompanying Annual Report on Form 10-K of Mississippi Power Company for the year ended December 31, 2017, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Annual Report on Form 10-K of Mississippi Power Company for the year ended December 31, 2017, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of Mississippi Power Company for the year ended December 31, 2017, fairly presents, in all material respects, the financial condition and results of operations of Mississippi Power Company.

/s/Anthony L. Wilson

Anthony L. Wilson
Chairman, President and Chief Executive Officer

/s/Moses H. Feagin

Moses H. Feagin
Vice President, Treasurer and
Chief Financial Officer

February 20, 2018

Exhibit 32(f)

**CERTIFICATION**

**18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

In connection with the accompanying Annual Report on Form 10-K of Southern Power Company for the year ended December 31, 2017, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Annual Report on Form 10-K of Southern Power Company for the year ended December 31, 2017, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of Southern Power Company for the year ended December 31, 2017, fairly presents, in all material respects, the financial condition and results of operations of Southern Power Company.

/s/Joseph A. Miller

Joseph A. Miller
Chairman, President and Chief Executive Officer

/s/William C. Grantham

William C. Grantham
Senior Vice President, Treasurer and
Chief Financial Officer

February 20, 2018

Exhibit 32(g)

**CERTIFICATION**

**18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

In connection with the accompanying Annual Report on Form 10-K of Southern Company Gas for the year ended December 31, 2017, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Annual Report on Form 10-K of Southern Company Gas for the year ended December 31, 2017, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of Southern Company Gas Company for the year ended December 31, 2017, fairly presents, in all material respects, the financial condition and results of operations of Southern Company Gas.

/s/Andrew W. Evans
Andrew W. Evans
Chairman, President, and Chief Executive Officer

/s/Elizabeth W. Reese
Elizabeth W. Reese
Executive Vice President, Chief Financial
Officer, and Treasurer

February 20, 2018

Exhibit 99(g)

*CONSOLIDATED FINANCIAL STATEMENTS*
*With Report of Independent Registered Public Accounting Firm*

# *SOUTHERN NATURAL GAS COMPANY, L.L.C.*

*As of December 31, 2017 and 2016 and*
*For the Year Ended December 31, 2017 and the Four Months Ended December 31, 2016*

**SOUTHERN NATURAL GAS COMPANY, L.L.C. AND SUBSIDIARY**
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**Report of Independent Registered Public Accounting Firm**

To the Board of Directors and Members of Southern Natural Gas Company, L.L.C.

***Opinion on the Financial Statements***

We have audited the accompanying consolidated balance sheets of Southern Natural Gas Company, L.L.C. and its subsidiary (the “Company”) as of December 31, 2017 and 2016, and the related consolidated statements of income, of cash flows and of members’ equity for the year ended December 31, 2017 and for the four months ended December 31, 2016, including the related notes (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of their operations and their cash flows for the year ended December 31, 2017 and for the four months ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America.

***Basis for Opinion***

These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (“PCAOB”) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the auditing standards of the PCAOB and in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

***Significant Transactions with Related Parties***

As discussed in Note 6 to the consolidated financial statements, the Company has entered into significant transactions with related parties.

*/s/ PricewaterhouseCoopers LLP*

Houston, Texas
February 14, 2018

We have served as the Company's auditor since 2012.

**SOUTHERN NATURAL GAS COMPANY, L.L.C. AND SUBSIDIARY**
**CONSOLIDATED STATEMENTS OF INCOME**
**(In Millions)**

| | Year Ended December 31, 2017 | Four Months Ended December 31, 2016 |
|---|---|---|
| Revenues | $ 544 | $ 230 |
| | | |
| Operating Costs and Expenses | | |
| Operations and maintenance | 146 | 39 |
| Depreciation and amortization | 85 | 27 |
| General and administrative | 30 | 13 |
| Taxes, other than income taxes | 37 | 13 |
| Total Operating Costs and Expenses | 298 | 92 |
| | | |
| Operating Income | 246 | 138 |
| | | |
| Other Income (Expense) | | |
| Earnings from equity investment | 8 | 2 |
| Interest, net | (69) | (26) |
| Other, net | (10) | 1 |
| Total Other Income (Expense) | (71) | (23) |
| | | |
| Net Income | $ 175 | $ 115 |

The accompanying notes are an integral part of these consolidated financial statements.

**SOUTHERN NATURAL GAS COMPANY, L.L.C. AND SUBSIDIARY**
**CONSOLIDATED BALANCE SHEETS**
**(In Millions)**

| | December 31, 2017 | December 31, 2016 |
|---|---|---|
| **ASSETS** | | |
| Current assets | | |
| Cash and cash equivalents | $ 4 | $ 4 |
| Accounts receivable, net | 35 | 47 |
| Accounts receivable from affiliates | 19 | 18 |
| Inventories | 18 | 19 |
| Other current assets | 6 | 7 |
| Total current assets | 82 | 95 |
| | | |
| Property, plant and equipment, net | 2,439 | 2,451 |
| Investment | 63 | 61 |
| Regulatory assets | 23 | 36 |
| Deferred charges and other assets | 35 | 32 |
| Total Assets | $ 2,642 | $ 2,675 |
| | | |
| **LIABILITIES AND MEMBERS' EQUITY** | | |
| Current liabilities | | |
| Current portion of debt | $ 13 | $ 500 |
| Accounts payable | 21 | 25 |
| Accounts payable to affiliates | 15 | 9 |
| Accrued interest | 17 | 19 |
| Accrued taxes, other than income taxes | 20 | 22 |
| Regulatory liabilities | 15 | 3 |
| Other current liabilities | 9 | 10 |
| Total current liabilities | 110 | 588 |
| | | |
| Long-term liabilities and deferred credits | | |
| Long-term debt, net of debt issuance costs | 1,102 | 706 |
| Other long-term liabilities and deferred credits | 76 | 22 |
| Total long-term liabilities and deferred credits | 1,178 | 728 |
| Total Liabilities | 1,288 | 1,316 |
| | | |
| Commitments and contingencies(Note 9) | | |
| Members' Equity | 1,354 | 1,359 |
| Total Liabilities and Members' Equity | $ 2,642 | $ 2,675 |

The accompanying notes are an integral part of these consolidated financial statements.

**SOUTHERN NATURAL GAS COMPANY, L.L.C. AND SUBSIDIARY**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(In Millions)**

| | Year Ended December 31, 2017 | Four Months Ended December 31, 2016 |
|---|---|---|
| Cash Flows From Operating Activities | | |
| Net income | $ 175 | $ 115 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation and amortization | 85 | 27 |
| Earnings from equity investment | (8) | (2) |
| Other non-cash items | 1 | 1 |
| Distributions from equity investment earnings | 6 | 3 |
| Changes in components of working capital: | | |
| Accounts receivable | 8 | (7) |
| Regulatory assets | 2 | 5 |
| Accounts payable | 1 | 10 |
| Accrued interest | (2) | (7) |
| Accrued taxes, other than income | (2) | (4) |
| Regulatory liabilities | 12 | 1 |
| Other current assets and liabilities | 3 | — |
| Other long-term assets and liabilities | 50 | (1) |
| Net Cash Provided by Operating Activities | 331 | 141 |
| | | |
| Cash Flows From Investing Activities | | |
| Capital expenditures | (53) | (33) |
| Other, net | (5) | — |
| Net Cash Used in by Investing Activities | (58) | (33) |
| | | |
| Cash Flows From Financing Activities | | |
| Issuances of debt | 570 | 56 |
| Payments of debt | (659) | (56) |
| Debt issuance costs | (4) | — |
| Contributions from Members | 108 | 15 |
| Distributions to Members | (288) | (119) |
| Net Cash Used in Financing Activities | (273) | (104) |
| | | |
| Net Change in Cash and Cash Equivalents | — | 4 |
| Cash and Cash Equivalents, beginning of period | 4 | — |
| Cash and Cash Equivalents, end of period | $ 4 | $ 4 |
| | | |
| Supplemental Disclosure of Cash Flow Information | | |
| Cash paid during the period for interest (net of capitalized interest) | $ 69 | $ 24 |

The accompanying notes are an integral part of these consolidated financial statements.

**SOUTHERN NATURAL GAS COMPANY, L.L.C. AND SUBSIDIARY**
**CONSOLIDATED STATEMENTS OF MEMBERS' EQUITY**
**(In Millions)**

| | Year Ended December 31, 2017 | Four Months Ended December 31, 2016 |
|---|---|---|
| Beginning Balance | $ 1,359 | $ 1,348 |
| Net income | 175 | 115 |
| Contributions | 108 | 15 |
| Distributions | (288) | (119) |
| Ending Balance | $ 1,354 | $ 1,359 |

The accompanying notes are an integral part of these consolidated financial statements.

## 1. General

We are a Delaware limited liability company, originally formed in 1935 as a corporation. When we refer to “us,” “we,” “our,” “ours,” “the Company,” or “SNG,” we are describing Southern Natural Gas Company, L.L.C and its consolidated subsidiary.

The member interests in us are as follows:

- 50.0% - Kinder Morgan SNG Operator, LLC, an indirect subsidiary of Kinder Morgan, Inc. (KMI); and
- 50.0% - Evergreen Enterprise Holdings, LLC, an indirect subsidiary of The Southern Company (TSC).

Our operations are regulated by the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and the Energy Policy Act of 2005. The FERC approves tariffs that establish rates, cost recovery mechanisms and other terms and conditions of service to our customers.

Our primary business consists of the interstate transportation and storage of natural gas. Our natural gas pipeline system consists of approximately 6,900 miles of pipeline with a design capacity of approximately 4.2 billion cubic feet (Bcf) per day for natural gas. This pipeline system extends from supply basins in Louisiana, Mississippi and Alabama to market areas in Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina and Tennessee, including the metropolitan areas of Atlanta and Birmingham. We also own and operate 100% of the Muldon storage facility in Monroe County, Mississippi and own a 50% interest in Bear Creek Storage Company, L.L.C. (Bear Creek) in Bienville Parish, Louisiana. Bear Creek is a joint venture equally owned by us and Tennessee Gas Pipeline Company, L.L.C., an affiliate. Our interest in Bear Creek, the Muldon storage facilities and contracted storage have a combined working natural gas storage capacity of approximately 68 Bcf and peak withdrawal capacity of approximately 1.3 Bcf per day.

## 2. Summary of Significant Accounting Policies

### *Basis of Presentation*

We have prepared our accompanying consolidated financial statements in accordance with the accounting principles contained in the Financial Accounting Standards Board's (FASB) Accounting Standards Codification, the single source of United States Generally Accepted Accounting Principles (GAAP) and referred to in this report as the Codification. Additionally, certain amounts from the prior year have been reclassified to conform to the current presentation.

Management has evaluated subsequent events through February 14, 2018, the date the financial statements were available to be issued.

### *Principles of Consolidation*

We consolidate entities when we have the ability to control or direct the operating and financial decisions of the entity or when we have a significant interest in the entity that gives us the ability to direct the activities that are significant to that entity. The determination of our ability to control, direct or exert significant influence over an entity involves the use of judgment. All significant intercompany items have been eliminated in consolidation.

### *Use of Estimates*

Certain amounts included in or affecting our financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions which cannot be known with certainty at the time our financial statements are prepared. These estimates and assumptions affect the amounts we report for assets and liabilities, our revenues and expenses during the reporting period, and our disclosures, including as it relates to contingent assets and liabilities at the date of our financial statements. We evaluate these estimates on an ongoing basis, utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

In addition, we believe that certain accounting policies are of more significance in our financial statement preparation process than others, and set out below are the principal accounting policies we apply in the preparation of our consolidated financial statements.

***Cash Equivalents***

We define cash equivalents as all highly liquid short-term investments with original maturities of three months or less.

***Accounts Receivable, net***

We establish provisions for losses on accounts receivable due from shippers and operators if we determine that we will not collect all or part of the outstanding balance. We regularly review collectability and establish or adjust our allowance as necessary using the specific identification method. The allowance for doubtful accounts as of December 31, 2017 and 2016 was not significant.

***Inventories***

Our inventories, which consist of materials and supplies, are valued at weighted-average cost, and we periodically review for physical deterioration and obsolescence.

***Natural Gas Imbalances***

Natural gas imbalances occur when the amount of natural gas delivered from or received by a pipeline system or storage facility differs from the scheduled amount of gas to be delivered or received. We value these imbalances due to or from shippers and operators at current index prices. Imbalances are settled in cash or made up in-kind, subject to the terms of our FERC tariff. Imbalances due from others are reported on our accompanying Consolidated Balance Sheets in "Other current assets." Imbalances owed to others are reported on our accompanying Consolidated Balance Sheets in "Other current liabilities." We classify all imbalances due from or owed to others as current as we expect to settle them within a year.

***Property, Plant and Equipment, net***

Our property, plant and equipment is recorded at its original cost of construction or, upon acquisition, at either the fair value of the assets acquired or the cost to the entity that first placed the asset in utility service. For constructed assets, we capitalize all construction-related direct labor and material costs, as well as indirect construction costs. Our indirect construction costs primarily include an interest and equity return component (as more fully described below) and labor and related costs associated with supporting construction activities. The indirect capitalized labor and related costs are based upon estimates of time spent supporting construction projects.

We use the composite method to depreciate property, plant and equipment. Under this method, assets with similar economic characteristics are grouped and depreciated as one asset. The FERC-accepted depreciation rate is applied to the total cost of the group until the net book value equals the salvage value. For certain general plant, the asset is depreciated to zero. As part of periodic filings with the FERC, we also re-evaluate and receive approval for our depreciation rates. When property, plant and equipment is retired, accumulated depreciation and amortization is charged for the original cost of the assets in addition to the cost to remove, sell or dispose of the assets, less salvage value. We do not recognize gains or losses unless we sell land or an entire operating unit (as approved by the FERC). In those instances where we receive recovery in rates related to losses on dispositions of operating units, we record a regulatory asset for the estimated recoverable amount.

Included in our property balances are base gas and working gas at our storage facilities. We periodically evaluate natural gas volumes at our storage facilities for gas losses. When events or circumstances indicate a loss has occurred, we recognize a loss on our accompanying Consolidated Statements of Income or defer the loss as a regulatory asset on our accompanying Consolidated Balance Sheets if deemed probable of recovery through future rates charged to customers.

We capitalize a carrying cost (an allowance for funds used during construction or AFUDC) on debt and equity funds related to the construction of long-lived assets. This carrying cost consists of a return on the investment financed by debt and a return on the investment financed by equity. The debt portion is calculated based on our average cost of debt. Interest costs capitalized are included as a reduction in "Interest, net" on our accompanying Consolidated Statements of Income. The equity portion is calculated based on our most recent FERC approved rate of return. Equity amounts capitalized are included in "Other, net" on our accompanying Consolidated Statements of Income. The amounts of capitalized AFUDC were not significant for the year ended December 31, 2017 and the four months ended December 31, 2016.

***Asset Retirement Obligations (ARO)***

We record liabilities for obligations related to the retirement and removal of long-lived assets used in our businesses. We record, as liabilities, the fair value of ARO on a discounted basis when they are incurred and can be reasonably estimated, which is typically at the time the assets are installed or acquired. Amounts recorded for the related assets are increased by the amount of these obligations. Over time, the liabilities increase due to the change in their present value, and the initial capitalized costs are depreciated over the useful lives of the related assets. The liabilities are eventually extinguished when the asset is taken out of service.

We are required to operate and maintain our natural gas pipelines and storage systems, and intend to do so as long as supply and demand for natural gas exists, which we expect for the foreseeable future. Therefore, we believe that we cannot reasonably estimate the ARO for the substantial majority of our assets because these assets have indeterminate lives. We continue to evaluate our ARO and future developments could impact the amounts we record. Our recorded ARO were not significant as of December 31, 2017 and 2016.

***Asset and Investment Impairments***

We evaluate our assets and investments for impairment when events or circumstances indicate that their carrying values may not be recovered. These events include market declines that are believed to be other than temporary, changes in the manner in which we intend to use a long-lived asset, decisions to sell an asset or investment and adverse changes in market conditions or in the legal or business environment such as adverse actions by regulators. If an event occurs, which is a determination that involves judgment, we evaluate the recoverability of our carrying value based on either (i) the long-lived asset's ability to generate future cash flows on an undiscounted basis or (ii) the fair value of the investment in an unconsolidated affiliate. If an impairment is indicated, or if we decide to sell a long-lived asset or group of assets, we adjust the carrying value of the asset downward, if necessary, to its estimated fair value.

Our fair value estimates are generally based on assumptions market participants would use, including market data obtained through the sales process or an analysis of expected discounted future cash flows. There were no impairments for the year ended December 31, 2017 and the four months ended December 31, 2016.

***Equity Method of Accounting***

We account for investments, which we do not control but do have the ability to exercise significant influence, by the equity method of accounting. Under this method, our equity investments are carried originally at our acquisition cost, increased by our proportionate share of the investee’s net income and by contributions made, and decreased by our proportionate share of the investee’s net losses and by distributions received.

***Revenue Recognition***

We are subject to FERC regulations, therefore fees and rates established under our tariff are a function of our cost of providing services to our customers, including a reasonable return on our invested capital. Our revenues are primarily generated from natural gas transportation and storage services and include estimates of amounts earned but unbilled. We estimate these unbilled revenues based on contract data, regulatory information, and preliminary throughput and allocation measurements, among other items. Revenues for all services are based on the thermal quantity of gas delivered or subscribed at a price specified in the contract. For our transportation services and storage services, we recognize reservation revenues on firm contracted capacity ratably over the contract period regardless of the amount of natural gas that is transported or stored. For interruptible or volumetric-based services, we record revenues when physical deliveries of natural gas are made at the agreed upon delivery point or when gas is injected or withdrawn from the storage facility. For contracts with step-up or step-down rate provisions that are not related to changes in levels of service, we recognize reservation revenues ratably over the contract life. The revenues we collect may be subject to refund in a rate proceeding.

For the year ended December 31, 2017, revenues from our two largest customers (one affiliate and one third party) were approximately $269 million, and $55 million, each of which exceeded 10% of our operating revenues. For the the four months ended December 31, 2016, revenues from our largest affiliate and non-affiliate customers were approximately $89 million and $52 million, respectively, each of which exceeded 10% of our operating revenues for that period, see Note 6. Amounts for both periods include contracted capacity released by customers to third parties.

In September 2016, we recognized revenue of $37 million from an early termination of a customer contract.

***Environmental Matters***

We capitalize or expense, as appropriate, environmental expenditures. We capitalize certain environmental expenditures required in obtaining rights-of-way, regulatory approvals or permitting as part of the construction. We accrue and expense environmental costs that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation. We generally do not discount environmental liabilities to a net present value, and we record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. Generally, our recording of these accruals coincides with our completion of a feasibility study or our commitment to a formal plan of action. We recognize receivables for anticipated associated insurance recoveries when such recoveries are deemed to be probable.

We routinely conduct reviews of potential environmental issues and claims that could impact our assets or operations. These reviews assist us in identifying environmental issues and estimating the costs and timing of remediation efforts. We also routinely adjust our environmental liabilities to reflect changes in previous estimates. In making environmental liability estimations, we consider the material effect of environmental compliance, pending legal actions against us, and potential third-party liability claims. Often, as the remediation evaluation and effort progresses, additional information is obtained, requiring revisions to estimated costs. These revisions are reflected in our income in the period in which they are reasonably determinable. For more information on our environmental matters, see Note 9.

***Other Contingencies***

We recognize liabilities for other contingencies when we have an exposure that indicates it is both probable that a liability has been incurred and the amount of loss can be reasonably estimated. Where the most likely outcome of a contingency can be reasonably estimated, we accrue an undiscounted liability for that amount. Where the most likely outcome cannot be estimated, a range of potential losses is established and if no one amount in that range is more likely than any other, the low end of the range is accrued.

***Postretirement Benefits***

We maintain a postretirement benefit plan covering certain of our former employees that we have made contributions to in the past. These contributions are invested until the benefits are paid to plan participants. The net benefit cost of this plan is recorded on our accompanying Consolidated Statements of Income and is a function of many factors including expected returns on plan assets and amortization of certain deferred gains and losses. For more information on our policies with respect to our postretirement benefit plan, see Note 5.

In accounting for our postretirement benefit plan, we record an asset or liability based on the difference between the fair value of the plan's assets and the plan's benefit obligation. Any deferred amounts related to unrecognized gains and losses or changes in actuarial assumptions are recorded on our Consolidated Balance Sheets as a regulatory asset or liability until those gains or losses are recognized on our accompanying Consolidated Statements of Income.

***Income Taxes***

We are a limited liability company and are not subject to federal or state income taxes. Our Members are responsible for income taxes on their allocated share of taxable income which may differ from income for financial statement purposes due to differences in the tax basis and financial reporting basis of assets and liabilities. However, we are subject to Texas margin tax (a revenue based calculation).

***Regulatory Assets and Liabilities***

Our interstate natural gas pipeline and storage operations are subject to the jurisdiction of the FERC and are accounted for in accordance with Accounting Standards Codification Topic 980, “Regulated Operations.” Under these standards, we record regulatory assets and liabilities that would not be recorded for non-regulated entities. Regulatory assets and liabilities represent probable future revenues or expenses associated with certain charges and credits that are expected to be recovered from or refunded to customers through the ratemaking process. Items to which we apply regulatory accounting requirements include certain postretirement employee benefit plan costs, losses on reacquired debt, taxes related to an equity return component on regulated capital projects prior to our change in legal structure to a non taxable entity, certain differences between gas retained and gas consumed in operations, amounts associated with the Tax Cuts and Jobs Act of 2017 (2017 Tax Reform) and other costs included in, or expected to be included in, future rates. For more information on our regulated operations, see Note 8.

### 3. Property, Plant and Equipment, net

Our property, plant and equipment, net consisted of the following (in millions, except for %):

| | Annual Depreciation Rates % | December 31, 2017 | December 31, 2016 |
|---|---|---|---|
| Transmission and storage facilities | 0.9-2.25 | $ 3,648 | $ 3,570 |
| General plant | 3.33-20 | 19 | 25 |
| Intangible plant | 5-10 | 20 | 19 |
| Other | | 129 | 116 |
| Accumulated depreciation and amortization(a) | | (1,412) | (1,344) |
| | | 2,404 | 2,386 |
| Land | | 13 | 12 |
| Construction work in progress | | 22 | 53 |
| Property, plant and equipment, net | | $ 2,439 | $ 2,451 |

(a) The composite weighted average depreciation rate for the year ended December 31, 2017 and the four months ended December 31, 2016 was approximately 2.3%.

### 4. Debt

We classify our debt based on the contractual maturity dates of the underlying debt instruments. We defer costs associated with debt issuance over the applicable term. These costs are then amortized as interest expense on our accompanying Consolidated Statements of Income.

The following table summarizes the net carrying value of our outstanding debt (in millions):

| | December 31, 2017 | December 31, 2016 |
|---|---|---|
| 5.90% Notes due April 2017 | $ — | $ 500 |
| 4.40% Notes due June 2021 | 300 | 300 |
| 7.35% Notes due February 2031 | 153 | 153 |
| 8.00% Notes due March 2032 | 258 | 258 |
| 4.80% Senior Notes due March 2047 | 400 | — |
| Credit Facility | 13 | — |
| | 1,124 | 1,211 |
| Less: Unamortized discount and debt issuance costs | 9 | 5 |
| Total debt | $ 1,115 | $ 1,206 |
| Less: Current portion of debt | 13 | 500 |
| Total long-term debt | $ 1,102 | $ 706 |

***Credit Facility***

Effective September 1, 2016, we entered into a $75 million, unsecured, 5-year revolving credit facility (Credit Facility). The facility is with a syndicate of financial institutions with Barclays Bank PLC as the administrative agent. Borrowings under our Credit Facility can be used for working capital and other general corporate purposes and are included within the caption “Current portion of debt” on our accompanying Consolidated Balance Sheet.

Our Credit Facility borrowings bear interest at either (i) London Interbank Offered Rate (LIBOR) plus an applicable margin ranging from 0.875% to 1.50% per annum based on our credit ratings or (ii) the greatest of the (a) Federal Funds Effective rate plus ½ of 1%, (b) the Prime Rate in effect for such day, and (c) the LIBOR rate for a one-month Eurodollar loan plus 1%, plus, in each case, an applicable margin ranging from nil to 1.5%. In addition, we have agreed to pay the administrative agent a commitment fee, based on our credit rating, ranging from 0.075% to 0.200%.

Our Credit Facility includes the following restrictive covenants:

- total debt divided by earnings before interest, income taxes, depreciation and amortization may not exceed 5.00 to 1.00;
- certain limitations on indebtedness, including payments and amendments;
- certain limitations on entering into mergers, consolidations, sales of assets and investments;
- limitations on granting liens; and
- prohibitions on making any distributions if an event of default exists or would exist upon making such a distribution.

As of December 31, 2017, we had $13 million of borrowings outstanding under our Credit Facility. As of December 31, 2016, we had no borrowings outstanding under our Credit Facility. As of December 31, 2017 and 2016, we were in compliance with all required covenants.

***Debt Issuance and Repayment***

On March 15, 2017 we issued $400 million of 4.80% senior notes due March 2047 and incurred debt issuance costs of $4 million. On April 3, 2017 we used the net proceeds of $399 million received from the debt issuance and equity contributions from our Members to repay $500 million of our 5.90% notes due April 2017.

***Debt Covenants***

Under our various other financing documents, we are subject to certain restrictions and covenants. The most restrictive of these include limitations on the incurrence of liens and limitations on sale-leaseback transactions. For the year ended December 31, 2017 and the four months ended December 31, 2016, we were in compliance with our debt-related covenants.

## 5. Retirement Benefits

***Pension and Retirement Savings Plans***

KMI maintains a pension plan and a retirement savings plan covering substantially all of its U.S. employees, including certain of our former employees. The benefits under the pension plan are determined under a cash balance formula. Under its retirement savings plan, KMI contributes an amount equal to 5% of participants' eligible compensation per year. KMI is responsible for benefits accrued under its plans and allocates certain costs based on a benefit allocation rate applied on payroll charged to its affiliates.

***Postretirement Benefits Plan***

We provide postretirement benefits, including medical benefits for a closed group of retirees. Medical benefits for pre-age 65 participants of this closed group may be subject to deductibles, co-payment provisions, dollar caps and other limitations on the amount of employer costs, and are subject to further benefit changes by KMI, the plan sponsor. Post-age 65 Medicare eligible participants are provided a fixed subsidy to purchase coverage through a retiree Medicare exchange. In addition, certain former employees continue to receive limited postretirement life insurance benefits. Our postretirement benefit plan costs were prefunded and were recoverable under prior rate case settlements. Currently, there is no cost recovery or related funding that is required as part of our current FERC approved rates, however, we can seek to recover any funding shortfall that may be required in the future. We do not expect to make any contributions to our postretirement benefit plan in 2018 and there were no contributions made in 2017 and 2016. KMI's postretirement plans have been merged. Prior to September 1, 2016, KMI used combined plan assets under the structure of the plans of its affiliated entities to fund participant benefits, including participants of affiliated entities.

*Postretirement Benefit Obligation, Plan Assets and Funded Status*

Our postretirement benefit obligations and net benefit costs are primarily based on actuarial calculations. We use various assumptions in performing these calculations, including those related to the return that we expect to earn on our plan assets, the estimated cost of health care when benefits are provided under our plan and other factors. A significant assumption we utilize is the discount rates used in calculating the benefit obligations. The discount rate used in the measurement of our postretirement benefit obligation is determined by matching the timing and amount of our expected future benefit payments for our postretirement benefit obligation to the average yields of various high-quality bonds with corresponding maturities. The service and interest cost components of net periodic benefit cost (credit) for our other postretirement benefit plan are estimated by utilizing a full yield curve approach by applying the specific spot rates along the yield curve used in the determination of the benefit obligation to their underlying projected cash flows.

The table below provides information about our postretirement benefit plan (in millions):

| | Year Ended December 31, 2017 | Four Months Ended December 31, 2016 |
|---|---|---|
| Change in plan assets: | | |
| Fair value of plan assets - beginning of period | $ 58 | $ 57 |
| Actual return on plan assets | 5 | 2 |
| Benefits paid | (3) | (1) |
| Fair value of plan assets - end of period | $ 60 | $ 58 |
| Change in postretirement benefit obligation: | | |
| Postretirement benefit obligation - beginning of period | $ 29 | $ 30 |
| Interest cost(a) | 1 | — |
| Actuarial gain(b) | — | — |
| Benefits paid | (3) | (1) |
| Postretirement benefit obligation - end of period | $ 27 | $ 29 |
| Reconciliation of funded status: | | |
| Fair value of plan assets | $ 60 | $ 58 |
| Less: Postretirement benefit obligation | 27 | 29 |
| Net asset at December 31(c) | $ 33 | $ 29 |

(a) Amount during the four months ended December 31, 2016 was less than $500,000.
(b) Amounts during the year ended December 31, 2017 and the four months ended December 31, 2016 were less than $500,000.
(c) Net asset amounts are included in "Deferred charges and other assets" on our accompanying Consolidated Balance Sheets.

*Plan Assets*

The primary investment objective of our plan is to ensure that, over the long-term life of the plan, an adequate pool of sufficiently liquid assets exists to meet the benefit obligations to retirees and beneficiaries. Investment objectives are long-term in nature covering typical market cycles. Any shortfall of investment performance compared to investment objectives is generally the result of economic and capital market conditions. Although actual allocations vary from time to time from our targeted allocations, the target allocations of our postretirement plan's assets are 30% equity, 30% fixed income and 40% master limited partnerships.

Below are the details of the postretirement benefit plan assets by class and a description of the valuation methodologies used for assets measured at fair value.

- Level 1 assets' fair values are based on quoted market prices for the instruments in actively traded markets. Included in this are equities and master limited partnerships using the quoted prices in actively traded markets;
- Level 2 assets' fair values are primarily based on pricing, data representative of quoted prices for similar assets in active markets (or identical assets in less active markets). Included in this are short term investment funds which are valued at cost plus calculated interest; and
- Plan assets with fair values that are based on the net asset value per share, or its equivalent (NAV), as reported by the issuers are determined based on the fair value of the underlying securities as of the valuation date and include private limited partnerships and fixed income trusts. The plan assets measured at NAV are not categorized within the fair value hierarchy described above, but are separately identified in the table below.

Listed below are the fair values of the plan's assets that are recorded at fair value by class and categorized by fair value measurement used at December 31, 2017 and 2016 (in millions):

| | 2017 | | | 2016 | | |
|---|---|---|---|---|---|---|
| | Level 1 | Level 2 | Total | Level 1 | Level 2 | Total |
| Short-term investment fund (money market) | $ — | $ 1 | $ 1 | $ — | $ 1 | $ 1 |
| Equity securities, domestic | 5 | — | 5 | 3 | — | 3 |
| Master limited partnerships | 14 | — | 14 | 14 | — | 14 |
| Total assets in fair value hierarchy | $ 19 | $ 1 | $ 20 | $ 17 | $ 1 | $ 18 |
| | | | | | | |
| Investments measured at NAV(a) | | | 40 | | | 40 |
| Investments at fair value | | | $ 60 | | | $ 58 |

(a) In accordance with Subtopic 820-10 of Accounting Standards Update (ASU) No. 2015-07, *Fair Value Measurement (Topic 820)* , certain Plan assets that were measured at NAV per share (or its equivalent) have not been classified in the fair value hierarchy. The fair value of the fixed income trusts as of December 31, 2017 and 2016 is $18 million and $15 million, respectively. The fair value of the private limited partnerships as of December 31, 2017 and 2016 is $22 million and $25 million, respectively.

*Expected Payment of Future Benefits*

As of December 31, 2017, we expect the following benefit payments under our plan (in millions):

| Year | Total |
|---|---|
| 2018 | $ 3 |
| 2019 | 3 |
| 2020 | 2 |
| 2021 | 2 |
| 2022 | 2 |
| 2023 - 2027 | 9 |

*Actuarial Assumptions and Sensitivity Analysis*

Postretirement benefit obligations and net benefit costs are based on actuarial estimates and assumptions. The following table details the weighted average actuarial assumptions used in determining our postretirement plan obligations and net benefit costs.

| | 2017 | 2016 |
|---|---|---|
| | (%) | |
| Assumptions related to benefit obligations at December 31: | | |
| Discount rate | 3.45 | 3.63 |
| Assumptions related to benefit costs for the year ended December 31: | | |
| Discount rate for benefit obligations | 3.63 | 3.82 |
| Discount rate for interest on benefit obligations | 2.93 | 2.98 |
| Expected return on plan assets(a) | 7.00 | 7.25 |

(a) The expected return on plan assets listed in the table above is a pre-tax rate of return based on our portfolio of investments. We utilize an after-tax expected return on plan assets to determine our benefit costs, which is based on unrelated business income taxes with a weighted average rate of 21% for both 2017 and 2016.

Actuarial estimates for our postretirement benefits plan assumed a weighted average annual rate of increase in the per capita costs of covered health care benefits of 6.41%, gradually decreasing to 4.54% by the year 2038. A one-percentage point change in assumed health care trends would not have had a significant effect on the postretirement benefit obligation or interest costs as of and for the year ended December 31, 2017 and the four months ended December 31, 2016 .

*Components of Net Benefit Income*

The components of net benefit costs (income) are as follows (in millions):

| | Year Ended December 31, 2017 | Four Months Ended December 31, 2016 |
|---|---|---|
| Interest cost(a) | $ 1 | $ — |
| Expected return on plan assets | (3) | (1) |
| Amortization of prior service credit(a) | (2) | — |
| Net benefit income | $ (4) | $ (1) |

(a) Amounts during the four months ended December 31, 2016 were less than $500,000.

## 6. Related Party Transactions

***Affiliate Balances and Activities***

We enter into transactions with our affiliates within the ordinary course of business, including natural gas transportation services to and from affiliates under long-term contracts, storage contracts and various operating agreements, and the services are based on the same terms as non-affiliates. As of December 31, 2017 and 2016, we had approximately $1 million of natural gas imbalance receivable with our affiliates which is included in "Other current assets" on our accompanying Consolidated Balance Sheets.

We do not have employees and are operated by an indirect subsidiary of KMI; therefore, KMI employees provide services to us. Subsequent to TSC's acquisition, we entered into an Operations and Management Agreement (O&M Agreement) with Kinder Morgan SNG Operator, LLC, a subsidiary of KMI, whereby we reimburse KMI monthly for direct operating expenses incurred on our behalf and pay a fixed annual fee for general and administrative costs. The fixed fee for the year ended December 31, 2017 and the four months ended December 31, 2016 was $30 million and $13 million, respectively. The fixed fee will be $31 million for each of the years 2018 through 2020, and is subject to review and approval for each of the next four years pursuant to the O&M Agreement. These costs are reflected, as appropriate, in the "Operations and maintenance", "General and administrative" and "Capitalized costs" lines in the table below.

The following table shows revenues and costs from our affiliates (in millions):

| | Year Ended December 31, 2017 | Four Months Ended December 31, 2016 |
|---|---|---|
| Revenues | $ 200 | $ 67 |
| Operations and maintenance | 90 | 24 |
| General and administrative | 30 | 13 |
| Capitalized costs | 9 | 4 |

***Subsequent Event***

In January 2018, we made a cash distribution to our Members of $22 million and received contributions from our Members of approximately $21 million.

**7. Fair Value**

The following table reflects the carrying amount and estimated fair value of our outstanding debt balances (in millions):

| | As of December 31, | | | |
|---|---|---|---|---|
| | 2017 | | 2016 | |
| | Carrying Amount | Estimated Fair Value | Carrying Amount | Estimated Fair Value |
| Total debt | $1,115 | $1,302 | $1,206 | $1,312 |

We separate the fair values of our financial instruments into levels based on our assessment of the availability of observable market data and the significance of non-observable data used to determine the estimated fair value. We estimated the fair values of our outstanding debt balance primarily based on quoted market prices for the same or similar issues, a Level 2 fair value measurement. Our assessment and classification of an instrument within a level can change over time based on the maturity or liquidity of the instrument and this change would be reflected at the end of the period in which the change occurs. During the year ended December 31, 2017 and the four months ended December 31, 2016, there were no changes to the inputs and valuation techniques used to measure fair value, the types of instruments, or the levels in which they were classified.

## 8. Accounting for Regulatory Activities

***Regulatory Assets and Liabilities***

Regulatory assets and liabilities represent probable future revenues or expenses associated with certain charges and credits that will be recovered from or refunded to customers through the ratemaking process. As of December 31, 2017, the regulatory assets are being recovered in our rates, without earning a return, over a period of approximately one year to 27 years. Below are the details of our regulatory assets and liabilities as of (in millions):

| | December 31, | |
|---|---|---|
| | **2017** | **2016** |
| Current regulatory assets | | |
| Difference between gas retained and gas consumed in operations | $ 1 | $ 3 |
| Other | 1 | 1 |
| Total current regulatory assets(a) | 2 | 4 |
| Non-current regulatory assets | | |
| Taxes on capitalized funds used during construction(b) | 13 | 24 |
| Unamortized loss on reacquired debt | 9 | 10 |
| Other | 1 | 2 |
| Total non-current regulatory assets | 23 | 36 |
| Total regulatory assets | $ 25 | $ 40 |
| | | |
| Current regulatory liabilities | | |
| Difference between gas retained and gas consumed in operations | $ 12 | $ 1 |
| Other | 3 | 2 |
| Total current regulatory liabilities | 15 | 3 |
| Non-current regulatory liabilities | | |
| Postretirement benefits | 19 | 19 |
| Income taxes(b) | 55 | — |
| Other | 1 | 2 |
| Total non-current regulatory liabilities(c) | 75 | 21 |
| Total regulatory liabilities | $ 90 | $ 24 |

(a) Included in “Other current assets” on our accompanying Consolidated Balance Sheets.
(b) See “2017 Tax Reform” below.
(c) Included in “Other long-term liabilities and deferred credits” on our accompanying Consolidated Balance Sheets.

Our significant regulatory assets and liabilities include:

*Difference between gas retained and gas consumed in operations*

Amounts reflect the value of the difference between the gas retained and consumed in our operations. Pursuant to our tariff, these amounts are expected to be recovered from our customers in subsequent periods.

*Taxes on capitalized funds used during construction*

Amounts represent the recovery of deferred income taxes on AFUDC Equity recognized during the time prior to 2007 when we were a taxable entity. These amounts are included in our tariff rates and are recovered over the depreciable lives of the asset in which they apply.

*Unamortized loss on reacquired debt*

Amounts represent the deferred and unamortized portion of loss on reacquired debt which are recovered in our rates. Amounts are amortized over the original life of the debt issue, or in the case of refinanced debt, over the life of the new debt issue.

*Postretirement Benefits*

Amounts represent unrecognized gains and losses related to our postretirement benefit plan.

*2017 Tax Reform*

On December 22, 2017, the U.S. enacted the 2017 Tax Reform. Among the many provisions included in the 2017 Tax Reform is a provision to reduce the U.S. federal corporate income tax rate from 35% to 21% effective January 1, 2018. As income taxes are a component in our maximum recourse rates, the income tax rate change resulted in us recording a provisional $66 million non-cash charge to our earnings related to an adjustment to our deferred income tax related regulatory assets and liabilities. The charge was recorded as a reduction to Revenues of $55 million and an increase to Other, net of $11 million for the year ended December 31, 2017.

As the impact on the regulatory ratemaking process is currently uncertain, and we have not completed our assessment of the 2017 Tax Reform's effect, these amounts are subject to further adjustments. We continue to assess the impact of the 2017 Tax Reform on our business in order to complete our analysis. Any adjustments to our provisional amount will be reported in the reporting period in which any such adjustments are determined and may be material in the period in which the adjustments are made.

***Regulatory Assets Amortization***

Our amortizations of the regulatory assets for the year ended December 31, 2017 and the four months ended December 31, 2016 were $1 million, related to deferred losses on reacquired debt included in “Interest, net” on our accompanying Consolidated Statements of Income.

***Regulatory Matters***

*Rate Case*

On July 12, 2013, the FERC approved a comprehensive rate case settlement for SNG's general system-wide tariff rates. Under the settlement, we are required to file a new rate case no later than February 28, 2018 for new storage and transportation tariff rates to go into effect September 1, 2018. In August 2017, we commenced pre-filing settlement negotiations with our customers to try and resolve the rate proceeding prior to filing a rate case with FERC. We have filed on January 29, 2018 a request to FERC to extend the obligation to file the rate case from February 28 to May 1, 2018 in order to continue negotiations of a pre-filing settlement. If we were to succeed in obtaining a pre-filing settlement, new transportation, storage and park and loan tariff rates would go into effect September 1, 2018.

*Other*

We applied with the FERC on February 3, 2017 in Docket No. CP17-46-000 to expand our system in Georgia (Fairburn Expansion project) to provide additional firm transportation capacity of approximately 347,000 dekatherms per day in the Southeast market. The estimated capital cost of the project is approximately $240 million and its anticipated in-service date is October 1, 2018.

**9. Litigation, Environmental and Commitments**

We are party to various legal, regulatory and other matters arising from the day-to-day operations of our businesses that may result in claims against the Company. Although no assurance can be given, we believe, based on our experiences to date and taking into account established reserves, that the ultimate resolution of such items will not have a material adverse impact on our business, financial position, results of operations or cash flows. We believe we have meritorious defenses to the matters to which we are a party and intend to vigorously defend the Company. When we determine a loss is probable of occurring and is reasonably estimable, we accrue an undiscounted liability for such contingencies based on our best estimate using information available at that time. If the estimated loss is a range of potential outcomes and there is no better estimate within the range, we accrue the amount at the low end of the range. We disclose contingencies where an adverse outcome may be material, or in the judgment of management, we conclude the matter should otherwise be disclosed.

***Legal Proceedings***

*Cliffs Natural Resources (Cliffs)*

We filed a lawsuit against Cliffs in the Circuit Court of Jefferson County, Alabama (Case No. 68-CV-2014-900533) to determine whether Cliffs' longwall coal mining operations require the relocation of a large segment of our pipelines in Jefferson County, Alabama and who will be responsible for the cost of any such relocation. Prior to the initiation of the lawsuit, Cliffs notified us of its intent to conduct underground longwall coal mining operations in the vicinity of four of our pipelines in Jefferson County. Upon being informed by Cliffs that its planned coal mining operations would cause surface subsidence of three to six feet, we determined that such level of subsidence presented a safety hazard to our pipelines and that relocating the affected pipelines may be the safest and most economical option to mitigate the safety hazard. We alleged in the lawsuit that easements governing our property rights to operate our pipelines do not allow Cliffs' mining operations to proceed as planned. We also alleged, among other things, that if Cliffs is allowed to proceed with its mining plan, Cliffs should be responsible for the pipeline relocation costs and any other damages. We have completed the relocation of the pipelines, at a cost of approximately $34 million, to avoid the mining threat. On March 3, 2017, the parties reached a confidential settlement agreement to resolve all disputes related to the relocation and the lawsuit was dismissed in May 2017.

*General*

As of December 31, 2017, we had no accruals for our outstanding legal proceedings. As of December 31, 2016, we had less than $1 million accrued for our outstanding legal proceedings.

***Environmental Matters***

We are subject to environmental cleanup and enforcement actions from time to time. In particular, the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) generally imposes joint and several liability for cleanup and enforcement costs on current and predecessor owners and operators of a site, among others, without regard to fault or the legality of the original conduct, subject to the right of a liable party to establish a "reasonable basis" for apportionment of costs. Our operations are also subject to federal, state and local laws and regulations relating to protection of the environment. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in our operations, and there can be no assurance that we will not incur significant costs and liabilities. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies under the terms of authority of those laws, and claims for damages to property or persons resulting from our operations, could result in substantial costs and liabilities to us.

*Southeast Louisiana Flood Protection Litigation*

On July 24, 2013, the Board of Commissioners of the Southeast Louisiana Flood Protection Authority - East (SLFPA) filed a petition for damages and injunctive relief in a state district court for Orleans Parish, Louisiana against us and approximately 100 other energy companies, alleging that defendants' drilling, dredging, pipeline and industrial operations since the 1930's have caused direct land loss and increased erosion and submergence resulting in alleged increased storm surge risk, increased flood protection costs and unspecified damages to the plaintiff. The SLFPA asserts claims for negligence, strict liability, public nuisance, private nuisance, and breach of contract. Among other relief, the petition seeks unspecified monetary damages, attorney fees, interest, and injunctive relief in the form of abatement and restoration of the alleged coastal land loss including but not limited to backfilling and re-vegetation of canals, wetlands and reef creation, land bridge construction, hydrologic restoration, shoreline protection, structural protection, and bank stabilization. On August 13, 2013, the suit was removed to the U.S. District Court for the Eastern District of Louisiana. On February 13, 2015, the Court granted defendants' motion to dismiss the suit for failure to state a claim, and issued an order dismissing the SLFPA's claims with prejudice. On March 3, 2017, the Fifth Circuit Court of Appeals affirmed the U.S. District Court's decision, and the SLFPA's petition for writ of certiorari to the U.S. Supreme Court was denied on October 30, 2017, thereby resolving this matter in its entirety.

*Vintage Assets, Inc. Coastal Erosion Litigation*

On December 18, 2015, Vintage Assets, Inc. and several individual landowners filed a petition in the State District Court for Plaquemines Parish, Louisiana alleging that its 5,000 acre property is composed of coastal wetlands, and that we failed to maintain pipeline canals and banks, causing widening of the canals, land loss, and damage to the ecology and hydrology of the marsh, in breach of right of way agreements, prudent operating practices, and Louisiana law. The suit also claims that defendants' alleged failure to maintain pipeline canals and banks constitutes negligence and has resulted in encroachment of the canals, constituting trespass. The suit seeks in excess of $80 million in money damages, including recovery of litigation costs, damages for trespass, and money damages associated with an alleged loss of natural resources and projected reconstruction cost of replacing or restoring wetlands. The suit was removed to the U.S. District Court for the Eastern District of Louisiana. Our assets at issue were sold to Highpoint Gas Transmission, LLC in 2011, which was subsequently purchased by American Midstream Partners, LP. In response to our demand for defense and indemnity, American Midstream Partners agreed to pay 50% of joint defense costs and expenses, with a percentage of indemnity to be determined upon final resolution of the suit. On October 20, 2016, plaintiffs filed an amended complaint naming Highpoint Gas Transmission, LLC as an additional defendant. A non-jury trial was held during September 2017. We anticipate a ruling in the first quarter 2018. We will continue to vigorously defend the suit, and intend to appeal any adverse ruling that may result from the trial.

*Superfund Matters*

In our recorded environmental liabilities there were projects where we had received notice that we had been designated or could be designated as a Potentially Responsible Party (PRP) under CERCLA, commonly known as Superfund, or state equivalents for one site. On September 29, 2017, we entered into a Consent Decree after meeting the Environmental Protection Agency's requirements for a final settlement for the remaining liability at the Port Refinery Superfund site, including payment of a settlement amount which is the final judgment against us for the site.

*General*

Although it is not possible to predict the ultimate outcomes, we believe that the resolution of the environmental matters set forth in this note, and other matters to which we and our subsidiary are a party, will not have a material adverse effect on our business, financial position, results of operations or cash flows. As of December 31, 2017 and 2016, we had less than $1 million accrued for our environmental matters.

***Commitments***

*Capital Commitments*

As of December 31, 2017, we have capital commitments of $15 million, which we expect to spend during 2018. We have other planned capital and investment projects that are discretionary in nature, with no substantial contractual capital commitments made in advance of the actual expenditures.

*Transportation Commitments*

We have transportation commitments totaling $359 million as of December 31, 2017, which are primarily related to a transportation contract with our affiliate, Elba Express Company, L.L.C., which we expect to spend $32 million each year for the period from 2018 to 2022 and $199 million in total thereafter.

*Storage Commitments*

We have storage capacity commitments totaling $8 million as of December 31, 2017, most of which are related to storage capacity contracts with our equity investee, Bear Creek, which we expect to spend during 2018. We expect annual renewal of this contract to occur into the foreseeable future.

*Operating Leases*

We lease property, facilities and equipment under various operating leases. Our future minimum annual rental commitments under our operating leases as of December 31, 2017, are as follows (in millions):

| Year | Total |
|---|---|
| 2018 | $ 2 |
| 2019 | 2 |
| 2020 | 2 |
| 2021 | 2 |
| 2022 | 2 |
| Thereafter | 11 |
| Total | $ 21 |

Rent expense on our lease obligations for the year ended December 31, 2017 and the four months ended December 31, 2016 was approximately $2 million and $1 million, respectively, and is reflected in "Operations and maintenance" and "General and administrative" on our accompanying Consolidated Statements of Income. For certain operating leases related to shared facilities, we may be the primary obligor, but the rent expense is allocated to various KMI subsidiaries and is administered and funded by KMI.

**10. Recent Accounting Pronouncements**

***Accounting Standards Updates***

***Topic 606***

On May 28, 2014, the FASB issued ASU No. 2014-09, " *Revenue from Contracts with Customers* " followed by a series of related accounting standard updates (collectively referred to as "Topic 606"). Topic 606 is designed to create greater revenue recognition and disclosure comparability in financial statements. The provisions of Topic 606 include a five-step process by which an entity will determine revenue recognition, depicting the transfer of goods or services to customers in amounts reflecting the payment to which an entity expects to be entitled in exchange for those goods or services. Topic 606 requires certain disclosures about contracts with customers and provides more comprehensive guidance for transactions such as service revenue, contract modifications, and multiple-element arrangements.

Topic 606 will require that our revenue recognition policy disclosure include further detail regarding our performance obligations as to the nature, amount, timing, and estimates of revenue and cash flows generated from our contracts with customers. Topic 606 will also require disclosure of significant changes in contract asset and contract liability balances period to period and the amount of the transaction price allocated to performance obligations that are unsatisfied (or partially unsatisfied) as of the end of the reporting period, as applicable. We utilized the modified retrospective method to adopt the provisions of this standard effective January 1, 2018, which required us to apply the new revenue standard to (i) all new revenue contracts entered into after January 1, 2018 and (ii) all existing revenue contracts as of January 1, 2018 through a cumulative adjustment to equity. In accordance with this approach, our consolidated revenues for periods prior to January 1, 2018 will not be revised. The cumulative effect of the adoption of this standard as of January 1, 2018 was not material.

***ASU No. 2016-02***

On February 25, 2016, the FASB issued ASU No. 2016-02, " *Leases (Topic 842)* ." This ASU requires that lessees recognize assets and liabilities on the balance sheet for the present value of the rights and obligations created by all leases with terms of more than 12 months. The ASU also will require disclosures designed to give financial statement users information on the amount, timing, and uncertainty of cash flows arising from leases. ASU No. 2016-02 will be effective for us as of January 1, 2019. We are currently reviewing the effect of ASU No. 2016-02.

***ASU No. 2017-07***

On March 10, 2017, the FASB issued ASU No. 2017-07, " *Compensation - Retirement Benefits (Topic 715)* ." This ASU requires an employer to disaggregate the service cost component from the other components of net benefit cost, allows only the service cost component of net benefit cost to be eligible for capitalization, and addresses how to present the service cost component and the other components of net benefit cost in the income statement. We adopted ASU No. 2017-07 effective January 1, 2018 with no material impact to our financial statements.

***ASU No. 2018-01***

On January 25, 2018, the FASB issued ASU No. 2018-01, *"Land Easement Practical Expedient for Transition to Topic 842."* This ASU provides an optional transition practical expedient that, if elected, would not require companies to reconsider its accounting for existing or expired land easements before the adoption of Topic 842 and that were not previously accounted for as leases under Topic 840. ASU No. 2018-01 will be effective for us as of January 1, 2019, and earlier adoption is permitted. We are currently reviewing the effect of this ASU to our financial statements.