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, 2018

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 001-16189

NiSource Inc.

(Exact name of registrant as specified in its charter)

Delaware	35-2108964
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
801 East 86th Avenue Merrillville, Indiana	46410
(Address of principal executive offices)	(Zip Code)

(877) 647-5990
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock	New York

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

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

Indicate by check mark whether the registrant (1) has 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 registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).
Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) is not contained herein, and will not be contained, to the best of registrant's 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 definition of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12-b-2 of the Exchange Act.

Large accelerated filer ☑	Accelerated filer ☐	Emerging growth company ☐
Non-accelerated filer ☐	Smaller reporting company ☐	

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 Act). Yes ☐ No ☑

The aggregate market value of the registrant's common stock, par value $0.01 per share (the "Common Stock") held by non-affiliates was approximately $9,506,346,286 based upon the June 29, 2018, closing price of $26.28 on the New York Stock Exchange.

There were 372,494,365 shares of Common Stock outstanding as of February 12, 2019.

Documents Incorporated by Reference

Part III of this report incorporates by reference specific portions of the Registrant's Notice of Annual Meeting and Proxy Statement relating to the Annual Meeting of Stockholders to be held on May 7, 2019.

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DEFINED TERMS

The following is a list of abbreviations or acronyms that are used in this report:

NiSource Subsidiaries, Affiliates and Former Subsidiaries	
Capital Markets (former subsidiary)	NiSource Capital Markets, Inc.
Columbia (former subsidiary)	Columbia Energy Group
Columbia of Kentucky	Columbia Gas of Kentucky, Inc.
Columbia of Maryland	Columbia Gas of Maryland, Inc.
Columbia of Massachusetts	Bay State Gas Company
Columbia of Ohio	Columbia Gas of Ohio, Inc.
Columbia of Pennsylvania	Columbia Gas of Pennsylvania, Inc.
Columbia of Virginia	Columbia Gas of Virginia, Inc.
Company	NiSource Inc. and its subsidiaries, unless otherwise indicated by the context
CPG (former subsidiary)	Columbia Pipeline Group, Inc.
NIPSCO	Northern Indiana Public Service Company LLC
NiSource ("we," "us" or "our")	NiSource Inc.
NiSource Corporate Services	NiSource Corporate Services Company
NiSource Finance (former subsidiary)	NiSource Finance Corporation
Abbreviations	
ACE	Affordable clean energy
AFUDC	Allowance for funds used during construction
AMR	Automatic meter reading
AMRP	Accelerated Main Replacement Program
AOCI	Accumulated Other Comprehensive Income
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
ATM	At-the-market
Board	Board of Directors
BTA	Build-transfer agreement
CAA	Clean Air Act
CAP	Compliance Assurance Process
CCGT	Combined Cycle Gas Turbine
CCRs	Coal Combustion Residuals
CEP	Capital Expenditure Program
CERCLA	Comprehensive Environmental Response Compensation and Liability Act (also known as Superfund)
CO_2	Carbon dioxide
CPP	Clean Power Plan
DPU	Department of Public Utilities
DSIC	Distribution System Investment Charge
DSM	Demand Side Management
ECT	Environmental Cost Tracker
EERM	Environmental Expense Recovery Mechanism
EGUs	Electric Utility Steam Generating Units

DEFINED TERMS

ELG	Effluence limitations guidelines
EPA	United States Environmental Protection Agency
EPS	Earnings per share
FAC	Fuel adjustment clause
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FMCA	Federally Mandated Cost Adjustment
FTRs	Financial Transmission Rights
GAAP	Generally Accepted Accounting Principles
GCA	Gas cost adjustment
GCR	Gas cost recovery
GHG	Greenhouse gas
GSEP	Gas System Enhancement Program
GWh	Gigawatt hours
IRIS	Infrastructure Replacement and Improvement Surcharge
IRP	Infrastructure Replacement Program
IRS	Internal Revenue Service
IURC	Indiana Utility Regulatory Commission
LDCs	Local distribution companies
LIBOR	London inter-bank offered rate
LIFO	Last-in, first-out
MGP	Manufactured Gas Plant
MISO	Midcontinent Independent System Operator
Mizuho	Mizuho Corporate Bank Ltd.
MMDth	Million dekatherms
MW	Megawatts
MWh	Megawatt hours
NOL	Net Operating Loss
NTSB	National Transportation Safety Board
NYMEX	The New York Mercantile Exchange
NYSE	The New York Stock Exchange
OPEB	Other Postretirement and Postemployment Benefits
PCB	Polychlorinated biphenyls
PHMSA	U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration
PISCC	Post-in-service carrying charges
PPA	Purchase plan agreement
PSC	Public Service Commission
PTC	Production Tax Credits
PUC	Public Utility Commission
PUCO	Public Utilities Commission of Ohio
RCRA	Resource Conservation and Recovery Act
ROU	Right of use
SAB	Staff accounting bulletin
SAVE	Steps to Advance Virginia's Energy Plan

DEFINED TERMS

Separation	The separation of our natural gas pipeline, midstream and storage business from our natural gas and electric utility business accomplished through a pro rata distribution to holders of our outstanding common stock of all the outstanding shares of common stock of CPG. The separation was completed on July 1, 2015.
SEC	Securities and Exchange Commission
STRIDE	Strategic Infrastructure Development and Enhancement
Sugar Creek	Sugar Creek electric generating plant
TCJA	Tax Cuts and Jobs Act of 2017
TDSIC	Transmission, Distribution and Storage System Improvement Charge
VIE	Variable Interest Entity
VSCC	Virginia State Corporation Commission
WCE	Whiting Clean Energy

Note regarding forward-looking statements

This Annual Report on Form 10-K contains “forward-looking statements,” within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Investors and prospective investors should understand that many factors govern whether any forward-looking statement contained herein will be or can be realized. Any one of those factors could cause actual results to differ materially from those projected. These forward-looking statements include, but are not limited to, statements concerning our plans, strategies, objectives, expected performance, expenditures, recovery of expenditures through rates, stated on either a consolidated or segment basis, and any and all underlying assumptions and other statements that are other than statements of historical fact. All forward-looking statements are based on assumptions that management believes to be reasonable; however, there can be no assurance that actual results will not differ materially.

Factors that could cause actual results to differ materially from the projections, forecasts, estimates and expectations discussed in this Annual Report on Form 10-K include, among other things, our debt obligations; any changes to the credit rating of our or certain of our subsidiaries; our ability to execute our growth strategy; changes in general economic, capital and commodity market conditions; pension funding obligations; economic regulation and the impact of regulatory rate reviews; our ability to obtain expected financial or regulatory outcomes; our ability to adapt to, and manage costs related to, advances in technology; any changes in our assumptions regarding the financial implications of the Greater Lawrence Incident; potential incidents and other operating risks associated with our business; our ability to obtain sufficient insurance coverage; the outcome of legal and regulatory proceedings, investigations, incidents, claims and litigation; any damage to our reputation, including in connection with the Greater Lawrence Incident; compliance with environmental laws and the costs of associated liabilities; fluctuations in demand from residential and commercial customers; economic conditions of certain industries; the success of NIPSCO's electric generation strategy; the price of energy commodities and related transportation costs; the reliability of customers and suppliers to fulfill their payment and contractual obligations; potential impairments of goodwill or definite-lived intangible assets; changes in taxation and accounting principles; the impact of an aging infrastructure; the impact of climate change; potential cyber-attacks; construction risks and natural gas costs and supply risks; extreme weather conditions; the attraction and retention of a qualified workforce; the ability of our subsidiaries to generate cash; uncertainties related to the expected benefits of the Separation; our ability to manage new initiatives and organizational changes; the performance of third-party suppliers and service providers; and other matters set forth in Item 1A, “Risk Factors” of this report, many of which risks are beyond our control. In addition, the relative contributions to profitability by each business segment, and the assumptions underlying the forward-looking statements relating thereto, may change over time.

All forward-looking statements are expressly qualified in their entirety by the foregoing cautionary statements. We undertake no obligation to, and expressly disclaims any such obligation to, update or revise any forward-looking statements to reflect changed assumptions, the occurrence of anticipated or unanticipated events or changes to the future results over time or otherwise, except as required by law.

ITEM 1. BUSINESS

NISOURCE INC.

NiSource Inc. is an energy holding company under the Public Utility Holding Company Act of 2005 whose subsidiaries are fully regulated natural gas and electric utility companies serving approximately 4.0 million customers in seven states. NiSource is the successor to an Indiana corporation organized in 1987 under the name of NIPSCO Industries, Inc., which changed its name to NiSource on April 14, 1999.

NiSource is one of the nation's largest natural gas distribution companies, as measured by number of customers. NiSource's principal subsidiaries include NiSource Gas Distribution Group, Inc., a natural gas distribution holding company, and NIPSCO, a gas and electric company. NiSource derives substantially all of its revenues and earnings from the operating results of these rate-regulated businesses.

On September 13, 2018, a series of fires and explosions occurred in Lawrence, Andover and North Andover, Massachusetts related to the delivery of natural gas by Columbia of Massachusetts (referred to herein as the "Greater Lawrence Incident"). The Greater Lawrence Incident resulted in one fatality and a number of injuries, damaged multiple homes and businesses, and caused the temporary evacuation of significant portions of each municipality. The Massachusetts Governor's Office declared a state of emergency, authorizing the Massachusetts DPU to order another utility company to coordinate the restoration of utility services in Lawrence, Andover and North Andover. The incident resulted in the interruption of gas for approximately 7,500 gas meters, the majority of which serve residences and of which approximately 700 serve businesses, and the interruption of other utility service more broadly in the area. Columbia of Massachusetts has replaced the cast iron and bare steel gas pipeline system in the affected area and restored service to nearly all of the gas meters. Refer to Note 18-C. "Legal Proceedings," and E. "Other Matters," in the Notes to Consolidated Financial Statements for more information.

NiSource's reportable segments are: Gas Distribution Operations and Electric Operations. The following is a summary of the business for each reporting segment. Refer to Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 22, "Segments of Business," in the Notes to Consolidated Financial Statements for additional information for each segment.

Gas Distribution Operations

Our natural gas distribution operations serve approximately 3.5 million customers in seven states and operate approximately 60,000 miles of pipeline located in our service areas described below. Through our wholly-owned subsidiary NiSource Gas Distribution Group, Inc., we own six distribution subsidiaries that provide natural gas to approximately 2.6 million residential, commercial and industrial customers in Ohio, Pennsylvania, Virginia, Kentucky, Maryland and Massachusetts. Additionally, we distribute natural gas to approximately 832,000 customers in northern Indiana through our wholly-owned subsidiary NIPSCO.

Electric Operations

We generate, transmit and distribute electricity through our subsidiary NIPSCO to approximately 472,000 customers in 20 counties in the northern part of Indiana and engage in wholesale and transmission transactions. NIPSCO owns and operates two coal-fired electric generating stations: four units at R.M. Schahfer located in Wheatfield, IN and one unit at Michigan City located in Michigan City, IN. The two operating facilities have a generating capacity of 2,080 MW. NIPSCO also owns and operates Sugar Creek, a CCGT plant located in West Terre Haute, IN with generating capacity of 571 MW, three gas-fired generating units located at NIPSCO's coal-fired electric generating stations with a generating capacity of 186 MW and two hydroelectric generating plants with a generating capacity of 16 MW: Oakdale located at Lake Freeman in Carroll County, IN and Norway located at Lake Schahfer in White County, IN. These facilities provide for a total system operating generating capacity of 2,853 MW.

In May 2018, NIPSCO completed the retirement of two coal-burning units (Units 7 and 8) at Bailly Generating Station, located in Chesterton, IN. These units had a generating capacity of approximately 460 MW. Refer to Note 18-E, "Other Matters," in the Notes to Consolidated Financial Statements for additional information on these retirements.

NIPSCO's transmission system, with voltages from 69,000 to 765,000 volts, consists of 2,963 circuit miles. NIPSCO is interconnected with five neighboring electric utilities. During the year ended December 31, 2018, NIPSCO generated 69.4% and purchased 30.6% of its electric requirements.

NIPSCO participates in the MISO transmission service and wholesale energy market. MISO is a nonprofit organization created in compliance with FERC regulations to improve the flow of electricity in the regional marketplace and to enhance electric reliability. Additionally, MISO is responsible for managing energy markets, transmission constraints and the day-ahead, real-time, FTR and ancillary markets. NIPSCO transferred functional control of its electric transmission assets to MISO, and transmission service for NIPSCO occurs under the MISO Open Access Transmission Tariff.

ITEM 1. BUSINESS

NISOURCE INC.

Business Strategy

We focus our business strategy on our core, rate-regulated asset-based businesses with most of our operating income generated from the rate-regulated businesses. Our utilities continue to move forward on core infrastructure and environmental investment programs supported by complementary regulatory and customer initiatives across all seven states in which we operate. Our goal is to develop strategies that benefit all stakeholders as we address changing customer conservation patterns, develop more contemporary pricing structures, and embark on long-term investment programs. These strategies are intended to improve reliability and safety, enhance customer services and reduce emissions while generating sustainable returns.

In its 2018 Integrated Resource Plan submission to the IURC, NIPSCO laid out a plan to retire the R.M. Schahfer Generating Station (Units 14, 15, 17, and 18) by 2023 and Michigan City Generating Station (Unit 12) by 2028. These units represent 2,080 MW of generating capacity, equal to 72% of NIPSCO's remaining capacity after the retirement of Bailly Units 7 and 8 in May of 2018. The current replacement plan includes renewable sources of energy, including wind, solar, and battery storage to be obtained through a combination of NIPSCO ownership and PPAs. Refer to Note 18-E, "Other Matters," in the Notes to Consolidated Financial Statements for further discussion of these plans.

Competition and Changes in the Regulatory Environment

The regulatory frameworks applicable to our operations, at both the state and federal levels, continue to evolve. These changes have had and will continue to have an impact on our operations, structure and profitability. Management continually seeks new ways to be more competitive and profitable in this environment.

The Gas Distribution Operations companies have pursued non-traditional revenue sources within the evolving natural gas marketplace. These efforts include the sale of products and services upstream of the companies' service territory, the sale of products and services in the companies' service territories, and gas supply cost incentive mechanisms for service to their core markets. The upstream products are made up of transactions that occur between an individual Gas Distribution Operations company and a buyer for the sales of unbundled or rebundled gas supply and capacity. The on-system services are offered by us to customers and include products such as the transportation and balancing of gas on the Gas Distribution Operations company system. The incentive mechanisms give the Gas Distribution Operations companies an opportunity to share in the savings created from such situations as gas purchase prices paid below an agreed upon benchmark and their ability to reduce pipeline capacity charges with their customers.

Increased efficiency of natural gas appliances and improvements in home building codes and standards has contributed to a long-term trend of declining average use per customer. Residential usage for the year ended December 31, 2018 increased primarily due to colder weather in our operating area compared to the prior year. While historically rate design at the distribution level has been structured such that a large portion of cost recovery is based upon throughput rather than in a fixed charge, operating costs are largely incurred on a fixed basis and do not fluctuate due to changes in customer usage. As a result, Gas Distribution Operations have pursued changes in rate design to more effectively match recoveries with costs incurred. Each of the states in which Gas Distribution Operations operate has different requirements regarding the procedure for establishing changes to rate design. Columbia of Ohio restructured its rate design through a base rate proceeding and has adopted a "de-coupled" rate design which more closely links the recovery of fixed costs with fixed charges. Columbia of Massachusetts received regulatory approval of a decoupling mechanism which adjusts revenues to an approved benchmark level through a volumetric adjustment factor. Columbia of Maryland and Columbia of Virginia have regulatory approval for a revenue normalization adjustment for certain customer classes, a decoupling mechanism whereby monthly revenues that exceed or fall short of approved levels are reconciled in subsequent months. In a prior base rate proceeding, Columbia of Pennsylvania implemented a pilot residential weather normalization adjustment. Columbia of Maryland, Columbia of Virginia and Columbia of Kentucky have had approval for a weather normalization adjustment for many years. In a prior base rate proceeding, NIPSCO implemented a higher fixed customer charge for residential and small customer classes moving toward full straight fixed variable rate design.

Natural Gas Competition. Open access to natural gas supplies over interstate pipelines and the deregulation of the commodity price of gas has led to tremendous change in the energy markets. LDC customers and marketers can purchase gas directly from producers and marketers as an open, competitive market for gas supplies has emerged. This separation or "unbundling" of the transportation and other services offered by pipelines and LDCs allows customers to purchase the commodity independent of services provided by the pipelines and LDCs. The LDCs continue to purchase gas and recover the associated costs from their customers. Our Gas Distribution Operations' subsidiaries are involved in programs that provide customers the opportunity to purchase their natural gas requirements from third parties and use our Gas Distribution Operations' subsidiaries for transportation services.

Gas Distribution Operations competes with investor-owned, municipal, and cooperative electric utilities throughout its service areas as well as other regulated and unregulated natural gas intra and interstate pipelines and other alternate fuels, such as propane and fuel oil. Gas Distribution Operations continues to be a strong competitor in the energy market as a result of strong customer preference for natural gas. Competition with providers of electricity has traditionally been the strongest in the residential and commercial markets of Kentucky, southern Ohio, central Pennsylvania and western Virginia due to comparatively low electric rates. Natural gas competes with fuel oil and propane in the Massachusetts market mainly due to the installed base of fuel oil and propane-based heating which has comprised a declining percentage of the overall market over the last few years. However, fuel oil and propane are more viable in today's oil market.

Electric Competition. Indiana electric utilities generally have exclusive service areas under Indiana regulations, and retail electric customers in Indiana do not have the ability to choose their electric supplier. NIPSCO faces non-utility competition from other energy sources, such as self-generation by large industrial customers and other distributed energy sources.

Seasonality

A significant portion of our operations are subject to seasonal fluctuations in sales. During the heating season, which is primarily from November through March, revenues from gas sales are more significant, and during the cooling season, which is primarily June through September, revenues from electric sales are more significant, than in other months.

Other Relevant Business Information

Our customer base is broadly diversified, with no single customer accounting for a significant portion of revenues.

As of December 31, 2018, we had 8,087 employees of whom 3,154 were subject to collective bargaining agreements. Collective bargaining agreements for 1,918 employees are set to expire within one year.

For a listing of certain subsidiaries of NiSource refer to Exhibit 21.

We electronically file various reports with the SEC, including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to such reports, as well as our proxy statements for the Company's annual meetings of stockholders at *http://www.sec.gov*. Additionally, we make all SEC filings available without charge to the public on our web site at *http://www.nisource.com*.

ITEM 1A. RISK FACTORS

NISOURCE INC.

Our operations and financial results are subject to various risks and uncertainties, including those described below, that could adversely affect our business, financial condition, results of operations, cash flows, and the trading price of our common stock.

We have substantial indebtedness which could adversely affect our financial condition.

Our businesses are capital intensive and we rely significantly on long-term debt to fund a portion of our capital expenditures and repay outstanding debt, and on short-term borrowings to fund a portion of day-to-day business operations. We had total consolidated indebtedness of $9,132.6 million outstanding as of December 31, 2018. Our substantial indebtedness could have important consequences. For example, it could:

- limit our ability to borrow additional funds or increase the cost of borrowing additional funds;
- reduce the availability of cash flow from operations to fund working capital, capital expenditures and other general corporate purposes;
- limit our flexibility in planning for, or reacting to, changes in the business and the industries in which we operate;
- lead parties with whom we do business to require additional credit support, such as letters of credit, in order for us to transact such business;
- place us at a competitive disadvantage compared to competitors that are less leveraged;
- increase vulnerability to general adverse economic and industry conditions; and
- limit our ability to execute on our growth strategy, which is dependent upon access to capital to fund our substantial infrastructure investment program.

Some of our debt obligations contain financial covenants related to debt-to-capital ratios and cross-default provisions. Our failure to comply with any of these covenants could result in an event of default, which, if not cured or waived, could result in the acceleration of outstanding debt obligations.

A drop in our credit ratings could adversely impact our cash flows, results of operation, financial condition and liquidity.

The availability and cost of credit for our businesses may be greatly affected by credit ratings. The credit rating agencies periodically review our ratings, taking into account factors such as our capital structure, earnings profile, and, in 2018, the impacts of the TCJA and the Greater Lawrence Incident. In March 2018, Moody's affirmed our senior unsecured rating of Baa2 and our commercial paper rating of P-2, with stable outlooks. Moody's also affirmed NIPSCO's Baa1 rating and Columbia of Massachusetts's Baa2 rating, with stable outlooks. In May 2018, Standard & Poor's affirmed our BBB+ senior unsecured ratings and affirmed our commercial paper rating of A-2, but changed the outlook on each rating from stable to negative in September 2018 as a result of potential impacts of the Greater Lawrence Incident. In June 2018, Fitch affirmed our and NIPSCO's long-term issuer default ratings of BBB and upgraded the commercial paper rating to F2 from F3, with stable outlooks. A credit rating is not a recommendation to buy, sell or hold securities, and may be subject to revision or withdrawal at any time by the assigning rating organization.

We are committed to maintaining investment grade credit ratings, however, there is no assurance we will be able to do so in the future. Our credit ratings could be lowered or withdrawn entirely by a rating agency if, in its judgment, the circumstances warrant. Any negative rating action could adversely affect our ability to access capital at rates and on terms that are attractive. A negative rating action could also adversely impact our business relationships with suppliers and operating partners, who may be less willing to extend credit or offer us similarly favorable terms as secured in the past under such circumstances.

Certain of our subsidiaries have agreements that contain "ratings triggers" that require increased collateral in the form of cash, a letter of credit or other forms of security for new and existing transactions if the credit ratings of our or certain of our subsidiaries are dropped below investment grade. These agreements are primarily for insurance purposes and for the physical purchase or sale of gas or power. As of December 31, 2018, the collateral requirement that would be required in the event of a downgrade below the ratings trigger levels would amount to approximately $53.8 million. In addition to agreements with ratings triggers, there are other agreements that contain "adequate assurance" or "material adverse change" provisions that could necessitate additional credit support such as letters of credit and cash collateral to transact business.

If our or certain of our subsidiaries credit ratings were downgraded, especially below investment grade, financing costs and the principal amount of borrowings would likely increase due to the additional risk of our debt and because certain counterparties may require additional credit support as described above. Such amounts may be material and could adversely affect our cash flows, results of operations and financial condition. Losing investment grade credit ratings may also result in more restrictive covenants and reduced flexibility on repayment terms in debt issuances, lower share price and greater stockholder dilution from common equity issuances, in addition to reputational damage within the investment community.

We may not be able to execute our business plan or growth strategy, including utility infrastructure investments.

Business or regulatory conditions may result in us not being able to execute our business plan or growth strategy, including identified, planned and other utility infrastructure investments. Our customer and regulatory initiatives may not achieve planned results. Utility infrastructure investments may not materialize, may cease to be achievable or economically viable and may not be successfully completed. Natural gas may cease to be viewed as an economically and environmentally attractive fuel. Certain groups may continue to oppose natural gas delivery and infrastructure investments because of perceived environmental impacts associated with the natural gas supply chain and end use. Energy conservation, energy efficiency, distributed generation, energy storage, policies favoring electric heat over gas heat and other factors may reduce energy demand. Any of these developments could adversely affect our results of operations and growth prospects.

Adverse economic and market conditions or increases in interest rates could materially and adversely affect our results of operations, cash flows, financial condition and liquidity.

While the national economy is experiencing modest growth, we cannot predict how robust future growth will be or whether it will be sustained. Deteriorating or sluggish economic conditions in our operating jurisdictions could adversely impact our ability to maintain or grow our customer base and collect revenues from customers, which could reduce revenue growth and increase operating costs. In addition, a rising interest rate environment may lead to higher borrowing costs, which may adversely impact reported earnings, cost of capital and capital holdings. Rising interest rates and negative market or company events may also result in a decrease in the price of our shares of common stock.

We rely on access to the capital markets to finance our liquidity and long-term capital requirements, including expenditures for our utility infrastructure and to comply with future regulatory requirements, to the extent not satisfied by the cash flow generated by our operations. We have historically relied on long-term debt and on the issuance of equity securities to fund a portion of our capital expenditures and repay outstanding debt, and on short-term borrowings to fund a portion of day-to-day business operations. Successful implementation of our long-term business strategies, including capital investment, is dependent upon our ability to access the capital and credit markets, including the banking and commercial paper markets, on competitive terms and rates. An economic downturn or uncertainty, market turmoil, changes in tax policy, challenges faced by financial institutions, changes in our credit ratings, or a change in investor sentiment toward us or the utilities industry generally could adversely affect our ability to raise additional capital or refinance debt. Reduced access to capital markets and/or increased borrowing costs could reduce future net income and cash flows. Refer to Note 14, “Long-Term Debt,” in the Notes to Consolidated Financial Statements for information related to outstanding long-term debt and maturities of that debt.

If any of these risks or uncertainties limit our access to the credit and capital markets or significantly increase our cost of capital, it could limit our ability to implement, or increase the costs of implementing, our business plan, which, in turn, could materially and adversely affect our results of operations, cash flows, financial condition and liquidity.

Capital market performance and other factors may decrease the value of benefit plan assets, which then could require significant additional funding and impact earnings.

The performance of the capital markets affects the value of the assets that are held in trust to satisfy future obligations under defined benefit pension and other postretirement benefit plans. We have significant obligations in these areas and hold significant assets in these trusts. These assets are subject to market fluctuations and may yield uncertain returns, which fall below our projected rates of return. A decline in the market value of assets may increase the funding requirements of the obligations under the defined benefit pension and other postretirement benefit plans. Additionally, changes in interest rates affect the liabilities under these benefit plans; as interest rates decrease, the liabilities increase, which could potentially increase funding requirements. Further, the funding requirements of the obligations related to these benefits plans may increase due to changes in governmental regulations and participant demographics, including increased numbers of retirements or changes in life expectancy assumptions. In addition, lower asset returns result in increased expenses. Ultimately, significant funding requirements and increased pension or other postretirement benefit plan expense could negatively impact our results of operations and financial position.

ITEM 1A. RISK FACTORS

NISOURCE INC.

The majority of our revenues are subject to economic regulation and are exposed to the impact of regulatory rate reviews and proceedings.

Most of our revenues are subject to economic regulation at either the federal or state level. As such, the revenues generated by us are subject to regulatory review by the applicable federal or state authority. These rate reviews determine the rates charged to customers and directly impact revenues. Our financial results are dependent on frequent regulatory proceedings in order to ensure timely recovery of costs. In addition to our ongoing regulatory proceedings, the recovery of the Greater Lawrence pipeline replacement capital investment will be addressed in a future regulatory proceeding as discussed in Note 18, "Other Commitments and Contingencies - E. Other Matters" in the Notes to Consolidated Financial Statements. The outcomes of these proceedings are uncertain. Additionally, the costs of complying with current and future changes in environmental and federal pipeline safety laws and regulations are expected to be significant, and their recovery through rates will also be contingent on regulatory approval.

As a result of efforts to introduce market-based competition in certain markets where the regulated businesses conduct operations, we may compete with independent marketers for customers. This competition exposes us to the risk that certain infrastructure investments may not be recoverable and may affect results of our growth strategy and financial position.

Failure to adapt to advances in technology and manage the related costs could make us less competitive and negatively impact our results of operations and financial condition.

A key element of our business model is that generating power at central station power plants achieves economies of scale and produces power at a competitive cost. We continue to research, plan for, and implement new technologies that produce power or reduce power consumption. These technologies include renewable energy, distributed generation, energy storage, and energy efficiency. Advances in technology and changes in laws or regulations are reducing 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. This could cause power sales to decline and the value of our generating facilities to decline. In addition, customers are increasingly expecting enhanced communications regarding their electric and natural gas services, which, in some cases, may involve additional investments in technology. New technologies may require us to make significant expenditures to remain competitive and may result in the obsolescence of certain of our operating assets.

Our future success will depend, in part, on our ability to anticipate and successfully adapt to technological changes, to offer services that meet customer demands and evolving industry standards, and to recover all, or a significant portion of, any unrecovered investment in obsolete assets. A failure by us to effectively adapt to changes in technology and manage the related costs could harm our ability to remain competitive in the marketplace for our products, services and processes and could have a material adverse impact on our results of operations and financial condition.

The Greater Lawrence Incident has had and may have an additional material adverse impact on our financial condition, results of operations and cash flows.

In connection with the Greater Lawrence Incident, we have incurred and will incur various costs and expenses as set forth in Note 18 "Other Commitments and Contingencies - C. Legal Proceedings," and " - E. Other Matters" in the Notes to Consolidated Financial Statements.

As more information becomes known, including information resulting from the NTSB investigation, management's estimates and assumptions regarding the costs and expenses to be incurred and the financial impact of the Greater Lawrence Incident may change. A change in management’s estimates or assumptions could result in an adjustment that would have a material impact on our financial condition, results of operations and cash flows during the period in which such change occurred.

In addition, we are unable to predict the timing and amount of insurance recoveries. Total expenses related to the incident have exceeded the total amount of liability insurance coverage available under our policies. In addition, there may be certain types of damages, expenses or claimed costs, such as fines or penalties, that may be excluded under the policies. Losses for which we are not fully insured or that are not covered by insurance at all could materially adversely affect our results of operations, cash flows and financial position.

We may also incur additional costs associated with the Greater Lawrence Incident, beyond the amount currently anticipated, in connection with investigations by regulators, including the NTSB and Massachusetts DPU, as well as civil litigations. Further, state or federal legislation may be enacted that would require us to incur additional costs by mandating various changes, including changes to our operating practice standards for natural gas distribution operations and safety. If we are unable to recover the capital cost of the gas pipeline replacement in the impacted area or we incur a material amount of other costs that we are unable to recover through rates or offset through operational or other cost savings, our financial condition, results of operations, and cash flows could be materially and adversely affected.

Further, if it is determined that we did not comply with applicable statutes, regulations, rules, tariffs, or orders in connection with the Greater Lawrence Incident or in connection with the operations or maintenance of our natural gas system, and we are ordered to pay a material amount in customer refunds, penalties, or other amounts, our financial condition, results of operations, and cash flows could be materially and adversely affected.

Our gas distribution activities, as well as generation, transmission and distribution of electricity, involve a variety of inherent hazards and operating risks.

Our gas distribution activities, as well as generation, transmission, and distribution of electricity, involve a variety of inherent hazards and operating risks, including, but not limited to, gas leaks and over-pressurization, downed power lines, damage to our infrastructure by third parties, outages, environmental spills, mechanical problems and other incidents, which could cause substantial financial losses, as demonstrated in part by the Greater Lawrence Incident. In addition, these hazards and risks have resulted and may in the future result in serious injury or loss of life to employees and/or the general public, significant damage to property, environmental pollution, impairment of our operations, adverse regulatory rulings and reputational harm, which in turn could lead to substantial losses for us. The location of pipeline facilities, or generation, transmission, substation and distribution facilities near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from such incidents. As with the Greater Lawrence Incident, certain incidents have subjected and may in the future subject us to litigation or administrative or other legal proceedings from time to time, both civil and criminal, which could result in substantial monetary judgments, fines, or penalties against us, be resolved on unfavorable terms, and require us to incur significant operational expenses. The occurrence of incidents has in certain instances adversely affected and could in the future adversely affect our reputation, cash flows, financial position and/or results of operations. We maintain insurance against some, but not all, of these risks and losses.

We may be unable to obtain insurance on acceptable terms or at all, and the insurance coverage we do obtain may not provide protection against all significant losses.

Our ability to obtain insurance, as well as the cost and coverage of such insurance, are affected by developments affecting our business; international, national, state, or local events; and the financial condition of insurers. Insurance coverage may not continue to be available at all or at rates or terms acceptable to us. We expect the premiums we pay for our insurance coverage to significantly increase as a result of the Greater Lawrence Incident and market conditions. In addition, our insurance is not sufficient or effective under all circumstances and against all hazards or liabilities to which we are subject. For example, total expenses related to the Greater Lawrence Incident have exceeded the total amount of liability coverage available under our policies. Also, certain types of damages, expenses or claimed costs, such as fines and penalties, may be excluded under the policies. In addition, insurers providing liability insurance to us may raise defenses to coverage under the terms and conditions of the respective insurance policies that could result in a denial of coverage or limit the amount of insurance proceeds available to us. Any losses for which we are not fully insured or that are not covered by insurance at all could materially adversely affect our results of operations, cash flows, and financial position. For more information regarding our insurance programs in the context of the Greater Lawrence Incident, see Note 18, "Other Commitments and Contingencies - C. Legal Proceedings," and " - E. Other Matters" in the Notes to Condensed Consolidated Financial Statements.

The outcome of legal and regulatory proceedings, investigations, inquiries, claims and litigation related to our business operations, including those related to the Greater Lawrence Incident, may have a material adverse effect on our results of operations, financial position or liquidity.

We are involved in legal and regulatory proceedings, investigations, inquiries, claims and litigation in connection with our business operations, including the Greater Lawrence Incident, the most significant of which are summarized in Note 18, “Other Commitments and Contingencies” in the Notes to Consolidated Financial Statements. Our insurance is not expected to cover all costs and expenses we may incur relating to the Greater Lawrence Incident and may not fully cover other incidents that may occur in the future. Due to the inherent uncertainty of the outcomes of such matters, there can be no assurance that the resolution of any particular claim or proceeding would not have a material adverse effect on our results of operations, financial position or liquidity. If one or more of such matters were decided against us, the effects could be material to our results of operations in the period in which we would be required to record or adjust the related liability and could also be material to our cash flows in the periods that we would be required to pay such liability.

ITEM 1A. RISK FACTORS

NISOURCE INC.

We are exposed to significant reputational risks, which make us vulnerable to a loss of cost recovery, increased litigation and negative public perception.

As a utility company, we are subject to adverse publicity focused on the reliability of our services, the speed with which we are able to respond effectively to electric outages, natural gas leaks or events and related accidents and similar interruptions caused by storm damage or other unanticipated events, as well as our own or third parties' actions or failure to act. We are also subject to adverse publicity related to perceived environmental impacts. If customers, legislators, or regulators have or develop a negative opinion of us, this could result in less favorable legislative and regulatory outcomes or increased regulatory oversight, increased litigation and negative public perception. Recently, we have been subject to adverse publicity as a result of the Greater Lawrence Incident, and it is difficult to predict the ultimate impact of this adverse publicity. The foregoing may have continuing adverse effects on our business, results of operations, cash flow and financial condition.

Our businesses are regulated under numerous environmental laws. The cost of compliance with these laws, and changes to or additions to, or reinterpretations of the laws, could be significant. Liability from the failure to comply with existing or changed laws could have a material adverse effect on our business, results of operations, cash flows and financial condition.

Our businesses are subject to extensive federal, state and local environmental laws and rules that regulate, among other things, air emissions, water usage and discharges, and waste products such as coal combustion residuals. Compliance with these legal obligations require us to make expenditures for installation of pollution control equipment, remediation, environmental monitoring, emissions fees, and permits at many of our facilities. These expenditures are significant, and we expect that they will continue to be significant in the future. Furthermore, if we fail to comply with environmental laws and regulations or are found to have caused damage to the environment or persons, even if caused by factors beyond our control, that failure or harm may result in the assessment of civil or criminal penalties and damages against us and injunctions to remedy the failure or harm.

Existing environmental laws and regulations may be revised and new laws and regulations seeking to change environmental regulation of the energy industry may be adopted or become applicable to us. Revised or additional laws and regulations may result in significant additional expense and operating restrictions on our facilities or increased compliance costs, which may not be fully recoverable from customers through regulated rates and could, therefore, impact our financial position, financial results and cash flow. Moreover, such costs could materially affect the continued economic viability of one or more of our facilities.

An area of significant uncertainty and risk are the laws concerning emission of GHG. While we continue to reduce GHG emissions through priority pipeline replacement, energy efficiency, leak detection, and other programs, and expect to further reduce GHG emissions through increased use of renewable energy, GHG emissions are currently an expected aspect of the electric and natural gas business. Revised or additional future GHG legislation and/or regulation related to the generation of electricity or the extraction, production, distribution, transmission, storage and end use of natural gas could materially impact our financial position, financial results and cash flows.

Even in instances where legal and regulatory requirements are already known or anticipated, the original cost estimates for environmental capital projects, remediation of past environmental harm, or pollution reduction strategies and equipment can differ materially from the amount ultimately expended. The actual future expenditures depend on many factors, including the nature and extent of impact, the method of cleanup, the cost of raw materials, contractor costs, and the availability of cost recovery. Changes in costs and the ability to recover under regulatory mechanisms could affect our financial position, financial results and cash flows.

A significant portion of the gas and electricity we sell is used by residential and commercial customers for heating and air conditioning. Accordingly, fluctuations in weather, gas and electricity commodity costs and economic conditions impact demand of our customers and our operating results.

Energy sales are sensitive to variations in weather. Forecasts of energy sales are based on “normal” weather, which represents a long-term historical average. Significant variations from normal weather could have, and have had, a material impact on energy sales. Additionally, residential usage, and to some degree commercial usage, is sensitive to fluctuations in commodity costs for gas and electricity, whereby usage declines with increased costs, thus affecting our financial results. Lastly, residential and commercial customers’ usage is sensitive to economic conditions and factors such as unemployment, consumption and consumer confidence. Therefore, prevailing economic conditions affecting the demand of our customers may in turn affect our financial results.

Our business operations are subject to economic conditions in certain industries.

ITEM 1A. RISK FACTORS

NISOURCE INC.

Business operations throughout our service territories have been and may continue to be adversely affected by economic events at the national and local level where it operates. In particular, sales to large industrial customers, such as those in the steel, oil refining, industrial gas and related industries, may be impacted by economic downturns. The U.S. manufacturing industry continues to adjust to changing market conditions including international competition, increasing costs, and fluctuating demand for its products.

The implementation of NIPSCO's electric generation strategy, including the retirement of its coal generation units, may not achieve intended results.

On October 31, 2018, NIPSCO submitted its 2018 Integrated Resource Plan with the IURC setting forth its short- and long-term electric generation plans in an effort to maintain affordability while providing reliable, flexible and cleaner sources of power. The plan evaluated demand-side and supply-side resource alternatives to reliably and cost-effectively meet NIPSCO customers' future energy requirements over the ensuing 20 years. The preferred option within the Integrated Resource Plan sets forth a schedule to retire R.M. Schahfer Generating Station (Units 14, 15, 17, and 18) by 2023 and Michigan City Generating Station (Unit 12) by 2028. The current replacement plan includes renewable sources of energy, including wind, solar, and battery storage. However, there are inherent risks and uncertainties, including changes in market conditions, regulatory approvals, environmental regulations, commodity costs and customer expectations, which may impede NIPSCO's ability to achieve these intended results. NIPSCO's future success will depend, in part, on its ability to successfully implement its long-term electric generation plans, to offer services that meet customer demands and evolving industry standards, and to recover all, or a significant portion of, any unrecovered investment in obsolete assets. NIPSCO's electric generation strategy could require significant future capital expenditures, operating costs and charges to earnings that may negatively impact our financial position, financial results and cash flows.

Fluctuations in the price of energy commodities or their related transportation costs or an inability to obtain an adequate, reliable and cost-effective fuel supply to meet customer demands may have a negative impact on our financial results.

Our electric generating fleet is dependent on coal and natural gas for fuel, and our gas distribution operations purchase and resell much of the natural gas we deliver to our customers. These energy commodities are vulnerable to price fluctuations and fluctuations in associated transportation costs. From time to time, we have also used hedging in order to offset fluctuations in commodity supply prices. We rely on regulatory recovery mechanisms in the various jurisdictions in order to fully recover the commodity costs incurred in providing service. However, while we have historically been successful in the recovery of costs related to such commodity prices, there can be no assurance that such costs will be fully recovered through rates in a timely manner.

In addition, we depend on electric transmission lines, natural gas pipelines, and other transportation facilities owned and operated by third parties to deliver the electricity and natural gas we sell to wholesale markets, supply natural gas to our gas storage and electric generation facilities, and provide retail energy services to customers. If transportation is disrupted, or if capacity is inadequate, we may be unable to sell and deliver our gas and electric services to some or all of our customers. As a result, we may be required to procure additional or alternative electricity and/or natural gas supplies at then-current market rates, which, if recovery of related costs is disallowed, could have a material adverse effect on our businesses, financial condition, cash flows, results of operations and/or prospects.

We are exposed to risk that customers will not remit payment for delivered energy or services, and that suppliers or counterparties will not perform under various financial or operating agreements.

Our extension of credit is governed by a Corporate Credit Risk Policy, involves considerable judgment and is based on an evaluation of a customer or counterparty's financial condition, credit history and other factors. We monitor our credit risk exposure by obtaining credit reports and updated financial information for customers and suppliers, and by evaluating the financial status of our banking partners and other counterparties by reference to market-based metrics such as credit default swap pricing levels, and to traditional credit ratings provided by the major credit rating agencies. Adverse economic conditions could result in an increase in defaults by customers, suppliers and counterparties.

We have significant goodwill and definite-lived intangible assets. An impairment of goodwill or definite-lived intangible assets could result in a significant charge to earnings and negatively impact our compliance with certain covenants under financing agreements.

In accordance with GAAP, we test goodwill for impairment at least annually and review our definite-lived intangible assets for impairment when events or changes in circumstances indicate the carrying value may not be recoverable. Goodwill also is tested for impairment when factors, examples of which include reduced cash flow estimates, a sustained decline in stock price or market capitalization below book value, indicate that the carrying value may not be recoverable. We have tested and will continue to monitor the goodwill of Columbia of Massachusetts for impairment in connection with the Greater Lawrence Incident. To date, these tests do not indicate the need for an impairment of the goodwill balance. We would be required to record a charge in our financial statements for the period in which any impairment of the goodwill or definite-lived intangible assets is determined, negatively impacting the results of operations. A significant charge could impact the capitalization ratio covenant under certain financing agreements. We are subject to a financial covenant under our five-year revolving credit facility, which requires us to maintain a debt to capitalization ratio that does not exceed 70%. A similar covenant in a 2005 private placement note purchase agreement requires us to maintain a debt to capitalization ratio that does not exceed 75%. As of December 31, 2018, the ratio was 61.4%.

Changes in taxation and the ability to quantify such changes could adversely affect our financial results.

We are subject to taxation by the various taxing authorities at the federal, state and local levels where we do business. Legislation or regulation which could affect our tax burden could be enacted by any of these governmental authorities. For example, the TCJA includes numerous provisions that affect businesses, including changes to U.S. corporate tax rates, business-related exclusions, and deductions and credits. The outcome of regulatory proceedings regarding the extent to which the effect of reduced corporate tax rate will be shared with customers and the time period over which it will be shared could significantly impact future earnings and cash flows. Separately, a challenge by a taxing authority, our ability to utilize tax benefits such as carryforwards or tax credits, or a deviation from other tax-related assumptions may cause actual financial results to deviate from previous estimates.

Changes in accounting principles may adversely affect our financial results.

Future changes in accounting rules and associated changes in regulatory accounting may negatively impact the way we record revenues, expenses, assets and liabilities. These changes in accounting standards may adversely affect our financial condition and results of operations.

Aging infrastructure may lead to disruptions in operations and increased capital expenditures and maintenance costs, all of which could negatively impact our financial results.

We have risks associated with aging infrastructure assets. The age of these assets may result in a need for replacement, a higher level of maintenance costs, or unscheduled outages, despite efforts by us to properly maintain or upgrade these assets through inspection, scheduled maintenance and capital investment. In addition, the nature of the information available on aging infrastructure assets may make inspections, maintenance, upgrading and replacement of the assets particularly challenging. The failure to operate these assets as desired could result in gas leaks and other incidents and in our inability to meet firm service obligations, which could adversely impact revenues, and could also result in increased capital expenditures and maintenance costs, which, if not fully recovered from customers, could negatively impact our financial results.

The impacts of climate change, natural disasters, acts of terrorism, accidents or other catastrophic events may disrupt operations and reduce the ability to service customers.

A disruption or failure of natural gas distribution systems, or within electric generation, transmission or distribution systems, in the event of a major hurricane, tornado, terrorist attack, accident or other catastrophic event could cause delays in completing sales, providing services, or performing other critical functions. We have experienced disruptions in the past from hurricanes and tornadoes and other events of this nature. The occurrence of such events could adversely affect our financial position and results of operations. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. There is also a concern that climate change may exacerbate the risks to physical infrastructure. Such risks include heat stresses to power lines, storms that damage infrastructure, lake and sea level changes that damage the manner in which services are currently provided, droughts or other stresses on water used to supply services, and other extreme weather conditions. Climate change and the costs that may be associated with its impacts have the potential to affect our business in many ways, including increasing the costs we incur in providing our products and services, impacting the demand for and consumption of our products and services (due to change in both costs and weather patterns), and affecting the economic health of the regions in which we operate.

ITEM 1A. RISK FACTORS

NISOURCE INC.

A cyber-attack on any of our or certain third-party computer systems upon which we rely may adversely affect our ability to operate.

We are reliant on technology to run our business, which is dependent upon financial and operational computer systems to process critical information necessary to conduct various elements of our business, including the generation, transmission and distribution of electricity, operation of our gas pipeline facilities and the recording and reporting of commercial and financial transactions to regulators, investors and other stakeholders. In addition to general information and cyber risks that all large corporations face (*e.g.*, malware, unauthorized access attempts, phishing attacks, malicious intent by insiders and inadvertent disclosure of sensitive information), the utility industry faces evolving cybersecurity risks associated with protecting sensitive and confidential customer information, electric grid infrastructure, and natural gas infrastructure. Deployment of new business technologies represents a new and large-scale opportunity for attacks on our information systems and confidential customer information, as well as on the integrity of the energy grid and the natural gas infrastructure. Increasing large-scale corporate attacks in conjunction with more sophisticated threats continue to challenge power and utility companies. Any failure of our computer systems, or those of our customers, suppliers or others with whom we do business, could materially disrupt our ability to operate our business and could result in a financial loss and possibly do harm to our reputation.

Additionally, our information systems experience ongoing, often sophisticated, cyber-attacks by a variety of sources, including foreign sources, with the apparent aim to breach our cyber-defenses. Although we attempt to maintain adequate defenses to these attacks and work through industry groups and trade associations to identify common threats and assess our countermeasures, a security breach of our information systems could (i) impact the reliability of our generation, transmission and distribution systems and potentially negatively impact our compliance with certain mandatory reliability standards, (ii) subject us to reputational and other harm associated with theft or inappropriate release of certain types of information such as system operating information or information, personal or otherwise, relating to our customers or employees, (iii) impact our ability to manage our businesses, and/or (iv) subject us to legal and regulatory proceedings and claims from third parties, in addition to remediation costs, any of which, in turn, could have a material adverse effect on our businesses, cash flows, financial condition, results of operations and/or prospects.

Our capital projects and programs subject us to construction risks and natural gas costs and supply risks, and require numerous permits, approvals and certificates from various governmental agencies.

Our business requires substantial capital expenditures for investments in, among other things, capital improvements to our electric generating facilities, electric and natural gas distribution infrastructure, natural gas storage, and other projects, including projects for environmental compliance. We are engaged in intrastate natural gas pipeline modernization programs to maintain system integrity and enhance service reliability and flexibility. NIPSCO also is currently engaged in a number of capital projects, including environmental improvements to its electric generating stations, the construction of new transmission facilities, and new projects related to renewable energy. As we undertake these projects and programs, we may be unable to complete them on schedule or at the anticipated costs. Additionally, we may construct or purchase some of these projects and programs to capture anticipated future growth in natural gas production, which may not materialize, and may cause the construction to occur over an extended period of time.

Our existing and planned capital projects require numerous permits, approvals and certificates from federal, state, and local governmental agencies. If there is a delay in obtaining any required regulatory approvals or if we fail to obtain or maintain any required approvals or to comply with any applicable laws or regulations, we may not be able to construct or operate our facilities, we may be forced to incur additional costs, or we may be unable to recover any or all amounts invested in a project. We also may not receive the anticipated increases in revenue and cash flows resulting from such projects and programs until after their completion

To the extent that delays occur, costs become unrecoverable, or we otherwise become unable to effectively manage and complete our capital projects, our results of operations, cash flows, and financial condition may be adversely affected.

Sustained extreme weather conditions may negatively impact our operations.

We conduct our operations across a wide geographic area subject to varied and potentially extreme weather conditions, which may from time to time persist for sustained periods of time. Despite preventative maintenance efforts, persistent weather related stress on our infrastructure may reveal weaknesses in our systems not previously known to us or otherwise present various operational challenges across all business segments. Further, adverse weather may affect our ability to conduct operations in a manner that satisfies customer expectations or contractual obligations, including by causing service disruptions.

ITEM 1A. RISK FACTORS

NISOURCE INC.

Failure to attract and retain an appropriately qualified workforce could harm our results of operations.

We operate in an industry that requires many of our employees to possess unique technical skill sets. Events such as an aging workforce without appropriate replacements, the mismatch of skill sets to future needs, or the unavailability of contract resources may lead to operating challenges or increased costs. These operating challenges include lack of resources, loss of knowledge, and a lengthy time period associated with skill development. In addition, current and prospective employees may determine that they do not wish to work for us due to market, economic, employment and other conditions. Failure to hire and retain qualified employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, may adversely affect our ability to manage and operate our business. If we are unable to successfully attract and retain an appropriately qualified workforce, safety, service reliability, customer satisfaction and our results of operations could be adversely affected.

Some of our employees are subject to collective bargaining agreements. Our collective bargaining agreements are generally negotiated on an operating company basis. Any failure to reach an agreement on new labor contracts or to negotiate these labor contracts might result in strikes, boycotts or other labor disruptions. Labor disruptions, strikes or significant negotiated wage and benefit increases, whether due to union activities, employee turnover or otherwise, could have a material adverse effect on our businesses, results of operations and/or cash flows.

We are a holding company and are dependent on cash generated by our subsidiaries to meet our debt obligations and pay dividends on our stock.

We are a holding company and conduct our operations primarily through our subsidiaries. Substantially all of our consolidated assets are held by our subsidiaries. Accordingly, our ability to meet our debt obligations or pay dividends on our common stock and preferred stock is largely dependent upon cash generated by these subsidiaries. In the event a major subsidiary is not able to pay dividends or transfer cash flows to us, our ability to service our debt obligations or pay dividends could be negatively affected.

The Separation may result in significant tax liabilities.

The Separation, which was completed in July 2015, was conditioned on the receipt by us of a legal opinion to the effect that the distribution of CPG shares to our stockholders is expected to qualify as tax-free under Section 355 of the U.S. Internal Revenue Code (the "Internal Revenue Code"). Even though we have received such an opinion, the IRS could determine on audit that the distribution is taxable. Both us and our stockholders could incur significant U.S. Federal income tax liabilities if taxing authorities conclude the distribution is taxable.

If we cannot effectively manage new initiatives and organizational changes, we will be unable to address the opportunities and challenges presented by our strategy and the business and regulatory environment.

In order to execute on our sustainable growth strategy and enhance our culture of ongoing continuous improvement, we must effectively manage the complexity and frequency of new initiatives and organizational changes. If we are unable to make decisions quickly, assess our opportunities and risks, and implement new governance, managerial and organizational processes as needed to execute our strategy in this increasingly dynamic and competitive business and regulatory environment, our financial condition, results of operations and relationships with our business partners, regulators, customers and stockholders may be negatively impacted.

We outsource certain business functions to third-party suppliers and service providers, and substandard performance by those third parties could harm our business, reputation and results of operations.

Utilities rely on extensive networks of business partners and suppliers to support critical enterprise capabilities across their organizations. Global metrics indicate that deliveries from suppliers are slowing and that labor shortages are occurring in the energy sector. We outsource certain services to third parties in areas including construction services, information technology, materials, fleet, environmental, operational services and other areas. Outsourcing of services to third parties could expose us to inferior service quality or substandard deliverables, which may result in non-compliance (including with applicable legal requirements and industry standards), interruption of service or accidents, or reputational harm, which could negatively impact our results of operations. If any difficulties in the operations of these third-party suppliers and service providers, including their systems, were to occur, they could adversely affect our results of operations, or adversely affect our ability to work with regulators, unions, customers or employees.

Changes in the method for determining LIBOR and the potential replacement of the LIBOR benchmark interest rate could adversely affect our business, financial condition, results of operations and cash flows.

ITEM 1A. RISK FACTORS

NISOURCE INC.

Some of our indebtedness, including borrowings under our revolving credit agreement, bears interest at a variable rate based on LIBOR. From time to time, we also enter into hedging instruments to manage our exposure to fluctuations in the LIBOR benchmark interest rate. In addition, these hedging instruments, as well as hedging instruments that our subsidiaries use for hedging natural gas price and basis risk, rely on LIBOR-based rates to calculate interest accrued on certain payments that may be required to be made under these agreements, such as late payments or interest accrued if any cash collateral should be held by a counterparty. In July 2017, the United Kingdom Financial Conduct Authority (“FCA”), which regulates LIBOR, announced that the FCA intends to stop compelling banks to submit rates for the calculation of LIBOR after 2021. It is not possible to predict the effect of these changes, other reforms or the establishment of alternative reference rates in the United Kingdom or elsewhere. In the United States, efforts to identify a set of alternative U.S. dollar reference interest rates include proposals by the Alternative Reference Rates Committee of the Federal Reserve Board and the Federal Reserve Bank of New York. The Alternative Reference Rates Committee has proposed the Secured Overnight Financing Rate ("SOFR") as its recommended alternative to LIBOR, and the Federal Reserve Bank of New York began publishing SOFR rates in April 2018. SOFR is intended to be a broad measure of the cost of borrowing cash overnight that is collateralized by U.S. Treasury securities.

Any changes announced by the FCA, other regulators or any other successor governance or oversight body, or future changes adopted by such body, in the method pursuant to which the LIBOR rates are determined may result in a sudden or prolonged increase or decrease in the reported LIBOR rates. If that were to occur, the level of interest payments we incur may change. In addition, although certain of our LIBOR based obligations provide for alternative methods of calculating the interest rate payable on certain of our obligations if LIBOR is not reported, which include, without limitation, requesting certain rates from major reference banks in London or New York, uncertainty as to the extent and manner of future changes may result in interest rates and/or payments that are higher than, lower than or that do not otherwise correlate over time with, the interest rates or payments that would have been made on our obligations if a LIBOR-based rate was available in its current form.

ITEM 1B. UNRESOLVED STAFF COMMENTS

NISOURCE INC.

None.

ITEM 2. PROPERTIES

Discussed below are the principal properties held by us and our subsidiaries as of December 31, 2018.

Gas Distribution Operations

Refer to Item 1, "Business - Gas Distribution Operations" of this report for further information on Gas Distribution Operations properties.

Electric Operations

Refer to Item 1, "Business - Electric Operations" of this report for further information on Electric Operations properties.

Corporate and Other Operations

We own the Southlake Complex, our 325,000 square foot headquarters building located in Merrillville, Indiana.

Character of Ownership

Our principal properties and our subsidiaries principal properties are owned free from encumbrances, subject to minor exceptions, none of which are of such a nature as to impair substantially the usefulness of such properties. Many of our subsidiary offices in various communities served are occupied under leases. All properties are subject to routine liens for taxes, assessments and undetermined charges (if any) incidental to construction. It is our practice to regularly pay such amounts, as and when due, unless contested in good faith. In general, the electric lines, gas pipelines and related facilities are located on land not owned by us or our subsidiaries, but are covered by necessary consents of various governmental authorities or by appropriate rights obtained from owners of private property. We do not, however, generally have specific easements from the owners of the property adjacent to public highways over, upon or under which our electric lines and gas distribution pipelines are located. At the time each of the principal properties were purchased a title search was made. In general, no examination of titles as to rights-of-way for electric lines, gas pipelines or related facilities was made, other than examination, in certain cases, to verify the grantors' ownership and the lien status thereof.

ITEM 3. LEGAL PROCEEDINGS

For a description of our legal proceedings, see Note 18-C "Legal Proceedings" in the Notes to Consolidated Financial Statements.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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SUPPLEMENTAL ITEM. EXECUTIVE OFFICERS OF THE REGISTRANT

NISOURCE INC.

The following is a list of the Executive Officers of the Registrant, including their names, ages, offices held and other recent business experience, as of February 1, 2019.

Name	Age	Office(s) Held in Past 5 Years
Joseph Hamrock	55	President and Chief Executive Officer of NiSource since July 1, 2015.
		Executive Vice President and Group Chief Executive Officer of NiSource from May 2012 to July 2015.
Donald E. Brown	47	Executive Vice President and Chief Financial Officer of NiSource since June 2016.
		Executive Vice President, Chief Financial Officer and Treasurer of NiSource from July 2015 to June 2016.
		Executive Vice President, Finance Department of NiSource from March 2015 to July 2015.
		Vice President and Chief Financial Officer of UGI Utilities, a division of UGI Corporation (gas and electric utility company) from 2010 to March 2015.
Peter T. Disser	50	Vice President, Internal Audit of NiSource since January 2019.
		Chief Operating Officer of NiSource Corporate Services from September 2018 through December 2018.
		Vice President, Audit of NiSource from November 2017 to September 2018.
		Vice President of Planning and Analysis of NiSource from June 2016 to November 2017.
		Chief Financial Officer of NIPSCO from 2012 to June 2016.
Carrie J. Hightman	61	Executive Vice President and Chief Legal Officer of NiSource since 2007.
Violet G. Sistovaris	57	Executive Vice President and President, NIPSCO since October 2016.
		Executive Vice President, NIPSCO from June 2015 to October 2016.
		Senior Vice President and Chief Information Officer of NiSource from May 2014 to June 2015.
		Senior Vice President and Chief Information Officer of NiSource Corporate Services from 2008 to May 2014.
Suzanne K. Surface	54	Chief Services Officer of NiSource since January 2019.
		Vice President, Audit of NiSource from September 2018 through December 2018.
		Vice President, Transformation Office of NiSource from August 2018 to September 2018.
		Vice President, Corporate Services Customer Value of NiSource Corporate Services from November 2017 to August 2018.
		Vice President, Audit of NiSource from July 2015 to November 2017.
		Vice President Regulatory Strategy and Support of NiSource from July 2009 through June 2015.
Pablo A. Vegas	45	Executive Vice President and President, Gas Utilities since January 2019.
		Executive Vice President and Chief Restoration Officer of NiSource Corporate Services since September 2018 through December 2018.
		Executive President, Gas Segment and Chief Customer Officer of NiSource from May 2017 to September 2018.
		Executive Vice President and President, Columbia Gas Group from May 2016 to May 2017.
		President and Chief Operating Officer of American Electric Power Ohio Company from May 2012 to May 2016.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

NISOURCE INC.

NiSource's common stock is listed and traded on the New York Stock Exchange under the symbol "NI."

Holders of shares of NiSource's common stock are entitled to receive dividends if and when declared by NiSource's Board out of funds legally available, subject to the prior dividend rights of holders of our preferred stock or the depositary shares representing such preferred stock outstanding, and if full dividends have not been declared and paid on all outstanding shares of preferred stock in any dividend period, no dividend may be declared or paid or set aside for payment on our common stock. The policy of the Board has been to declare cash dividends on a quarterly basis payable on or about the 20th day of February, May, August, and November. At its February 1, 2019 meeting, the Board declared a quarterly common dividend of $0.20 per share, payable on February 20, 2019 to holders of record on February 11, 2019.

Although the Board currently intends to continue the payment of regular quarterly cash dividends on common shares, the timing and amount of future dividends will depend on the earnings of NiSource's subsidiaries, their financial condition, cash requirements, regulatory restrictions, any restrictions in financing agreements and other factors deemed relevant by the Board. There can be no assurance that NiSource will continue to pay such dividends or the amount of such dividends.

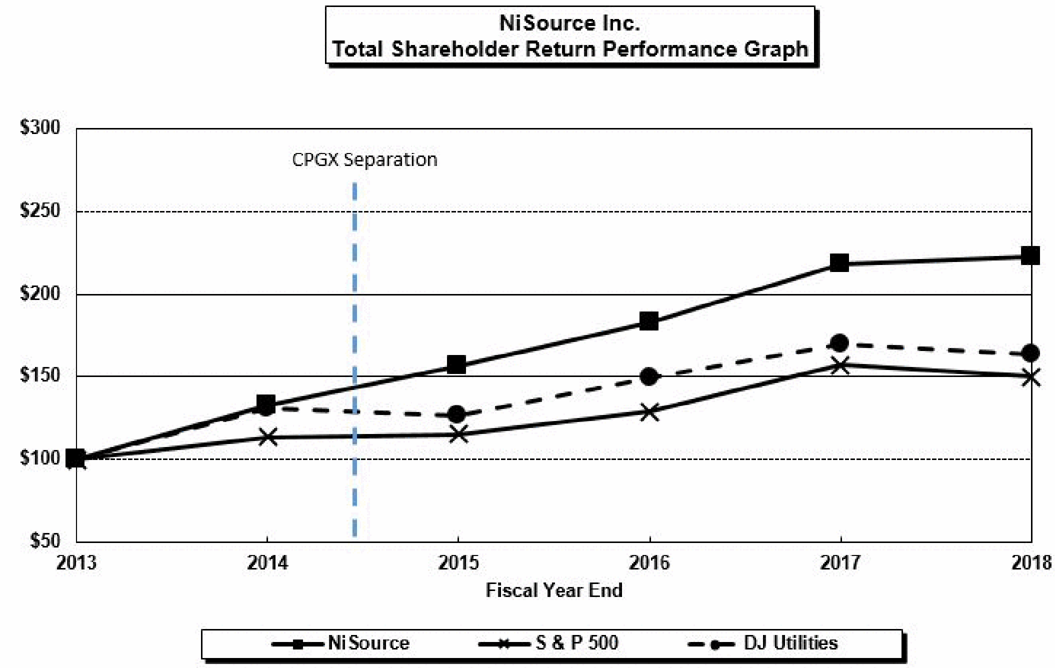
As of February 12, 2019, NiSource had 20,064 common stockholders of record and 372,494,365 shares outstanding.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

NISOURCE INC.

The graph below compares the cumulative total shareholder return of NiSource's common stock for the last five years with the cumulative total return for the same period of the S&P 500 and the Dow Jones Utility indices. On July 1, 2015, NiSource completed the Separation. Following the Separation, NiSource retained no ownership interest in CPG. The Separation is treated as a special dividend for purposes of calculating the total shareholder return, with the then-current market value of the distributed shares being deemed to have been reinvested on the Separation date in shares of NiSource common stock. A vertical line is included on the graph below to identify the periods before and after the Separation.



The foregoing performance graph is being furnished as part of this annual report solely in accordance with the requirement under Rule 14a-3(b)(9) to furnish stockholders with such information, and therefore, shall not be deemed to be filed or incorporated by reference into any filings by NiSource under the Securities Act or the Exchange Act.

The total shareholder return for NiSource common stock and the two indices is calculated from an assumed initial investment of $100 and assumes dividend reinvestment, including the impact of the distribution of CPG common stock in the Separation.

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ITEM 6. SELECTED FINANCIAL DATA

NISOURCE INC.

The selected data presented below as of and for the five years ended December 31, 2018, are derived from our Consolidated Financial Statements. The data should be read together with the Consolidated Financial Statements including the related notes thereto included in Item 8 of this Form 10-K.

Year Ended December 31, (*dollars in millions except per share data*)	**2018**	2017	2016	2015	2014
Statement of Income Data:					
Total Operating Revenues	**$ 5,114.5**	$ 4,874.6	$ 4,492.5	$ 4,651.8	$ 5,272.4
Net Income (Loss) Available to Common Shareholders	**(65.6)**	128.5	331.5	198.6	256.2
Balance Sheet Data:					
Total Assets	**21,804.0**	19,961.7	18,691.9	17,492.5	24,589.8
Capitalization					
Stockholders' equity	**5,750.9**	4,320.1	4,071.2	3,843.5	6,175.3
Long-term debt, excluding amounts due within one year	**7,105.4**	7,512.2	6,058.2	5,948.5	8,151.5
Total Capitalization	**$ 12,856.3**	$ 11,832.3	$ 10,129.4	$ 9,792.0	$ 14,326.8
Per Share Data:					
Basic Earnings (Loss) Per Share ($)	**$ (0.18)**	$ 0.39	$ 1.02	$ 0.63	$ 0.81
Diluted Earnings (Loss) Per Share ($)	**$ (0.18)**	$ 0.39	$ 1.01	$ 0.63	$ 0.81
Other Data:					
Dividends declared per common share ($)	**$ 0.78**	$ 0.70	$ 0.64	$ 0.83	$ 1.02
Common shares outstanding at the end of the year (in thousands)	**372,363**	337,016	323,160	319,110	316,037
Number of common stockholders	**19,889**	21,009	22,272	30,190	25,233
Dividends declared per Series A preferred share ($)	**$ 28.88**	$ —	$ —	$ —	$ —
Capital expenditures	**$ 1,814.6**	$ 1,753.8	$ 1,490.4	$ 1,367.5	$ 1,339.6
Number of employees	**8,087**	8,175	8,007	7,596	8,982

- In the second quarter of 2018, we completed the sale of 24,964,163 shares of $0.01 par value common stock at a price of $24.28 per share in a private placement to selected institutional and accredited investors and issued 400,000 shares of Series A preferred stock resulting in $400.0 million of gross proceeds or $393.9 million of net proceeds, after deducting commissions and sales expenses. Additionally, in the fourth quarter of 2018 we issued 20,000 shares of Series B preferred stock resulting in $500.0 million of gross proceeds or $486.1 million of net proceeds, after deducting commissions and sales expenses.
- During 2018 we recorded a loss of approximately $757 million for third-party claims and approximately $266 million for other incident-related expenses in connection with the Greater Lawrence Incident. Columbia of Massachusetts recorded $135 million for insurance recoveries through December 31, 2018. The amounts set forth above do not include the estimated capital cost of the pipeline replacement, which is set forth in " - E. Other Matters - Greater Lawrence Pipeline Replacement."
- During the second quarter of 2018 we executed a tender offer for $209.0 million of outstanding notes consisting of a combination of our 6.80% notes due 2019, 5.45% notes due 2020 and 6.125% notes due 2022. During the third quarter of 2018, we redeemed $551.1 million of outstanding notes representing the remainder of our 6.80% notes due 2019, 5.45% notes due 2020 and 6.125% notes due 2022. In conjunction with our debt retired, we recorded a $45.5 million loss on early extinguishment of long-term debt primarily attributable to early redemption premiums.
- The decrease in net income during 2017 was due primarily to increased tax expense as a result of the impact of adopting the provisions of the TCJA and a loss on early extinguishment of long-term debt, as discussed below.
- During the second quarter of 2017, we executed a tender offer for $990.7 million of outstanding notes consisting of a combination of our 6.40% notes due 2018, 6.80% notes due 2019, 5.45% notes due 2020, and 6.125% notes due 2022. In conjunction with the debt retired, we recorded a $111.5 million loss on early extinguishment of long-term debt, primarily attributable to early redemption premiums.
- Prior to the Separation, CPG closed the placement of $2,750.0 million in aggregate principal amount of senior notes. Using the proceeds from this offering, CPG made cash payments to us representing the settlement of inter-company borrowings and the payment of a one-time special dividend. In May 2015, using proceeds from the cash payments from CPG, we settled two bank term loans in the amount of $1,075.0 million and executed a tender offer for $750.0 million consisting of a combination of its 5.25% notes due 2017, 6.40% notes due 2018 and 4.45% notes due 2021. In conjunction with the debt

retired, we recorded a $97.2 million loss on early extinguishment of long-term debt, primarily attributable to early redemption premiums.

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

NISOURCE INC.

EXECUTIVE SUMMARY

This Management's Discussion and Analysis of Financial Condition and Results of Operations (Management's Discussion) analyzes our financial condition, results of operations and cash flows and those of our subsidiaries. It also includes management's analysis of past financial results and certain potential factors that may affect future results, potential future risks and approaches that may be used to manage those risks. See "Note regarding forward-looking statements" at the beginning of this report for a list of factors that may cause results to differ materially.

Management's Discussion is designed to provide an understanding of our operations and financial performance and should be read in conjunction with our Consolidated Financial Statements and related Notes to Consolidated Financial Statements in this annual report.

We are an energy holding company under the Public Utility Holding Company Act of 2005 whose subsidiaries are fully regulated natural gas and electric utility companies serving customers in seven states. We generate substantially all of our operating income through these rate-regulated businesses which are summarized for financial reporting purposes into two primary reportable segments: Gas Distribution Operations and Electric Operations.

Refer to the "Business" section under Item 1 of this annual report and Note 22, "Segments of Business," in the Notes to the Consolidated Financial Statements for further discussion of our regulated utility business segments.

Our goal is to develop strategies that benefit all stakeholders as we address changing customer conservation patterns, develops more contemporary pricing structures and embarks on long-term infrastructure investment programs. These strategies are intended to improve reliability and safety, enhance customer services and reduce emissions while generating sustainable returns. Additionally, we continue to pursue regulatory and legislative initiatives that will allow residential customers not currently on our system to obtain gas service in a cost effective manner. Refer also to the discussion of *Electric Supply* within our Electric Operations Segment discussion for additional information on our long term electric generation strategy.

Greater Lawrence Incident: The Greater Lawrence Incident occurred on September 13, 2018. During the year ended December 31, 2018, we recorded a loss of approximately $757 million for third-party claims and approximately $266 million for other incident-related expenses in connection with the Greater Lawrence Incident. The amounts set forth above do not include the estimated capital cost of the pipeline replacement described below and as set forth in " - E. Other Matters - Greater Lawrence Pipeline Replacement."

We estimate that total costs related to third-party claims as set forth in Note 18, "Other Commitments and Contingencies - C. Legal Proceedings," will range from $757 million to $790 million, depending on the final outcome of ongoing reviews and the number, nature, and value of third-party claims. We expect to incur a total of $330 million to $345 million in other incident-related costs.

We also expect to incur expenses for which we cannot estimate the amounts of or the timing at this time, including expenses associated with government investigations and fines, penalties or settlements with governmental authorities in connection with the Greater Lawrence Incident.

Columbia of Massachusetts recorded $135 million for insurance recoveries during 2018. Of this amount, $5 million was collected during 2018. We are currently unable to predict the amount and timing of future insurance recoveries. To the extent that we are not successful in collecting reimbursement in the amount recorded for such recoveries as of December 31, 2018, it could result in a charge to earnings.

Columbia of Massachusetts paid approximately $167 million for the replacement of the entire affected 45-mile cast iron and bare steel pipeline system that delivers gas to those impacted in the Greater Lawrence Incident during 2018. We estimate this replacement work will cost between $220 million and $230 million in total. Columbia of Massachusetts has provided notice to its property insurer of the Greater Lawrence Incident and discussions around the claim and recovery have commenced. The recovery of any capital investment not reimbursed through insurance will be addressed in a future regulatory proceeding. The outcome of such a proceeding is uncertain. If at any point Columbia of Massachusetts concludes it is probable that any portion of this capital investment is not recoverable through customer rates, that portion of the capital investment, if estimable, would be immediately charged to earnings.

As discussed in Note 8, "Regulatory Matters," in the Notes to Consolidated Financial Statements, Columbia of Massachusetts withdrew its petition for a base rate revenue increase, resulting in delayed increases in forecasted revenues and cash flows beginning the first quarter of 2019.

Additionally, as discussed in Note 6, "Goodwill and Other Intangible Assets," we concluded the Greater Lawrence Incident was a triggering event requiring a quantitative analysis of goodwill for the Columbia of Massachusetts reporting unit. While no impairment of the goodwill balance was recorded in 2018, future unfavorable events that transpire at Columbia of Massachusetts could trigger the need for another quantitative analysis and a goodwill impairment loss would be required if it's determined Columbia of Massachusetts fair value is less than its book value.

Refer to Note 18-C and E, "Legal Proceedings" and "Other Matters," in the Notes to Consolidated Financial Statements, "Summary of Consolidated Financial Results," "Results and Discussion of Segment Operation - Gas Distribution Operations," and "Liquidity and Capital Resources" in this Management's Discussion, and Part I. Item 1A. "Risk Factors" for additional information related to the Greater Lawrence Incident.

Summary of Consolidated Financial Results

Our operations are affected by the cost of sales. Cost of sales for the Gas Distribution Operations segment is principally comprised of the cost of natural gas used while providing transportation and distribution services to customers. Cost of sales for the Electric Operations segment is comprised of the cost of coal, related handling costs, natural gas purchased for the internal generation of electricity at NIPSCO and the cost of power purchased from third-party generators of electricity.

The majority of the cost of sales are tracked costs that are passed through directly to the customer resulting in an equal and offsetting amount reflected in operating revenues. As a result, we believe net revenues, a non-GAAP financial measure defined as operating revenues less cost of sales (excluding depreciation and amortization), provides management and investors a useful measure to analyze profitability. The presentation of net revenues herein is intended to provide supplemental information for investors regarding operating performance. Net revenues do not intend to represent operating income, the most comparable GAAP measure, as an indicator of operating performance and is not necessarily comparable to similarly titled measures reported by other companies.

For the years ended December 31, 2018, 2017 and 2016, operating income and a reconciliation of net revenues to the most directly comparable GAAP measure, operating income, was as follows:

Year Ended December 31, *(in millions)*	**2018**	2017	2016	2018 vs. 2017	2017 vs. 2016
Operating Income	**$ 124.7**	$ 921.2	$ 866.1	$ (796.5)	$ 55.1

Year Ended December 31, *(in millions, except per share amounts)*	**2018**	2017	2016	2018 vs. 2017	2017 vs. 2016
Operating Revenues	**$ 5,114.5**	$ 4,874.6	$ 4,492.5	$ 239.9	$ 382.1
Cost of sales (excluding depreciation and amortization)	**1,761.3**	1,518.7	1,390.2	242.6	128.5
Total Net Revenues	**3,353.2**	3,355.9	3,102.3	(2.7)	253.6
Other Operating Expenses	**3,228.5**	2,434.7	2,236.2	793.8	198.5
Operating Income	**124.7**	921.2	866.1	(796.5)	55.1
Total Other Deductions, Net	**(355.3)**	(478.2)	(352.5)	122.9	(125.7)
Income Taxes	**(180.0)**	314.5	182.1	(494.5)	132.4
Net Income (Loss)	**(50.6)**	128.5	331.5	(179.1)	(203.0)
Preferred dividends	**(15.0)**	—	—	(15.0)	—
Net Income (Loss) Available to Common Shareholders	**(65.6)**	128.5	331.5	(194.1)	(203.0)
Basic Earnings (Loss) Per Share	**$ (0.18)**	$ 0.39	$ 1.03	$ (0.57)	$ (0.64)
Basic Average Common Shares Outstanding	**356.5**	329.4	321.8	27.1	7.6

On a consolidated basis, we reported a loss to common shareholders of $65.6 million or $0.18 per basic share for the twelve months ended December 31, 2018 compared to net income available to common shareholders of $128.5 million or $0.39 per basic share for the same period in 2017. The decrease in net income during 2018 was primarily due to expenses related to the Greater Lawrence Incident restoration, dilution resulting from preferred stock dividend commitments and other changes in operating income, as discussed below, partially offset by the effects of implementing the TCJA and higher losses on early extinguishment of long-term debt expenses in 2017.

Operating Income

For the twelve months ended December 31, 2018, we reported operating income of $124.7 million compared to $921.2 million for the same period in 2017. The decreased operating income was primarily due to increased operation and maintenance expenses related to the Greater Lawrence Incident, decreased net revenues resulting from TCJA impacts on revenue and increased depreciation due to capital expenditures placed in service. These increases were partially offset by higher rates from infrastructure replacement programs and base-rate proceedings, decreased outside service costs and employee and administrative expenses, as well as net favorable effects of year-over-year weather variations, which increased revenue in 2018.

Other Deductions, Net

Other deductions, net reduced income by $355.3 million in 2018 compared to a reduction in income of $478.2 million in 2017. This change is primarily due to lower losses on early extinguishment of long-term debt in 2018 of $66.0 million, an interest rate swap settlement gain in 2018 of $46.2 million and higher actuarial investment returns resulting from pension contributions made in 2017. These favorable variances were partially offset by charitable contributions of $20.7 million in 2018 related to the Greater Lawrence Incident.

Income Taxes

On December 22, 2017, the President signed into law the TCJA, which, among other things, enacted significant changes to the Internal Revenue Code, as amended, including a reduction in the maximum U.S. federal corporate income tax rate from 35% to 21%, and certain other provisions related specifically to the public utility industry, including the continuation of certain interest expense deductibility and excluding 100% expensing of capital investments. These changes are effective January 1, 2018. GAAP requires the effect of a change in tax law to be recorded in the period of enactment. As a result, in December 2017, NiSource recorded a $161.1 million net increase in tax expense related primarily to the remeasurement of deferred tax assets for NOL carryforwards.

The decrease in income tax expense from 2017 to 2018 is primarily attributable to the decrease in the federal corporate income tax rate, true-ups to tax expense in 2018 to reflect regulatory outcomes associated with excess deferred income taxes, the effect of amortizing the regulatory liability associated with excess deferred income taxes and lower pre-tax income resulting from expenses incurred for the Greater Lawrence Incident.

Refer to "Liquidity and Capital Resources" below and Note 10, "Income Taxes," in the Notes to Consolidated Financial Statements for additional information on income taxes and the change in the effective tax rate.

Capital Investment

In 2018, we invested approximately $1.8 billion in cash capital expenditures across the gas and electric utilities. These expenditures were primarily aimed at furthering the safety and reliability of our gas distribution system, the Greater Lawrence Incident pipeline replacement, construction of new electric transmission assets and maintaining our existing electric generation fleet.

We continue to execute on an estimated $30 billion in total projected long-term regulated utility infrastructure investments and expect to invest approximately $1.6 to $1.7 billion in capital during 2019 to continue to modernize and improve our system across all seven states of our operating area.

Liquidity

As discussed in further detail below in "Liquidity and Capital Resources," the TCJA has and will continue to have an unfavorable impact on our liquidity. Additionally, expenses paid for the Greater Lawrence Incident are expected to have a short term negative impact on liquidity as recoveries from insurance lag behind our cash outlay. Liquidity will also be negatively impacted to the extent certain costs associated with the Greater Lawrence Incident are not recovered from insurance. Through income generated from operating activities, amounts available under our short-term revolving credit facility, commercial paper program, accounts receivable securitization facilities, long-term debt agreements and our ability to access the capital markets, we believe there is adequate capital available to fund our operating activities and capital expenditures and the effects of the Greater Lawrence Incident in 2019 and beyond. At December 31, 2018 and 2017, we had approximately $974.6 million and $998.9 million, respectively, of net liquidity available, consisting of cash and available capacity under credit facilities.

These factors and other impacts to the financial results are discussed in more detail within the following discussions of "Results and Discussion of Segment Operations" and "Liquidity and Capital Resources."

Regulatory Developments

In 2018, we continued to move forward on core infrastructure and environmental investment programs supported by complementary regulatory and customer initiatives across all seven states of our operating area. Refer to Note 8, "Regulatory Matters" and Note 18-E, "Other Matters," in the Notes to Consolidated Financial Statements for a complete discussion of key regulatory developments that transpired during 2018.

RESULTS AND DISCUSSION OF SEGMENT OPERATIONS

Presentation of Segment Information

Our operations are divided into two primary reportable segments: Gas Distribution Operations and Electric Operations.

NISOURCE INC.
Gas Distribution Operations

For the years ended December 31, 2018, 2017 and 2016, operating income and a reconciliation of net revenues to the most directly comparable GAAP measure, operating income, was as follows:

Year Ended December 31, *(in millions)*	**2018**	2017	2016	2018 vs. 2017	2017 vs. 2016
Operating Income (Loss)	**$ (254.1)**	$ 550.1	$ 569.7	$ (804.2)	$ (19.6)

Year Ended December 31, *(dollars in millions)*	**2018**	2017	2016	2018 vs. 2017	2017 vs. 2016
Net Revenues					
Operating revenues	**$ 3,419.5**	$ 3,102.1	$ 2,830.6	$ 317.4	$ 271.5
Less: Cost of sales (excluding depreciation and amortization)	**1,259.3**	1,005.0	895.4	254.3	109.6
Net Revenues	**2,160.2**	2,097.1	1,935.2	63.1	161.9
Operating Expenses					
Operation and maintenance	**1,908.1**	1,090.8	941.5	817.3	149.3
Depreciation and amortization	**301.0**	269.3	252.9	31.7	16.4
Loss on sale of assets and impairments, net	**0.2**	2.8	—	(2.6)	2.8
Other taxes	**205.0**	184.1	171.1	20.9	13.0
Total Operating Expenses	**2,414.3**	1,547.0	1,365.5	867.3	181.5
Operating Income (Loss)	**$ (254.1)**	$ 550.1	$ 569.7	$ (804.2)	$ (19.6)
Revenues					
Residential	**$ 2,248.3**	$ 2,029.4	$ 1,823.4	$ 218.9	$ 206.0
Commercial	**753.7**	669.4	588.1	84.3	81.3
Industrial	**228.6**	217.5	194.3	11.1	23.2
Off-System	**92.4**	111.8	94.4	(19.4)	17.4
Other	**96.5**	74.0	130.4	22.5	(56.4)
Total	**$ 3,419.5**	$ 3,102.1	$ 2,830.6	$ 317.4	$ 271.5
Sales and Transportation (MMDth)					
Residential	**280.3**	247.1	248.9	33.2	(1.8)
Commercial	**187.6**	169.3	165.6	18.3	3.7
Industrial	**555.7**	517.5	517.7	38.2	(0.2)
Off-System	**30.0**	39.0	39.6	(9.0)	(0.6)
Other	**—**	0.3	(0.1)	(0.3)	0.4
Total	**1,053.6**	973.2	971.7	80.4	1.5
Heating Degree Days	**5,562**	4,927	5,148	635	(221)
Normal Heating Degree Days	**5,610**	5,610	5,642	—	(32)
% Warmer than Normal	**(1)%**	(12)%	(9)%		
Gas Distribution Customers					
Residential	**3,194,662**	3,168,516	3,141,736	26,146	26,780
Commercial	**281,563**	280,362	279,556	1,201	806
Industrial	**6,038**	6,228	6,240	(190)	(12)
Other	**3**	4	—	(1)	4
Total	**3,482,266**	3,455,110	3,427,532	27,156	27,578

Gas Distribution Operations (continued)

Comparability of line item operating results may be impacted by regulatory, tax and depreciation trackers (other than those for cost of sales) that allow for the recovery in rates of certain costs. Therefore, increases in these tracked operating expenses are generally offset by increases in net revenues and have essentially no impact on net income.

2018 vs. 2017 Operating Income

For 2018, Gas Distribution Operations reported an operating loss of $254.1 million, a decrease in income of $804.2 million from the comparable 2017 period.

Net revenues for 2018 were $2,160.2 million, an increase of $63.1 million from the same period in 2017. The change in net revenues was primarily driven by:

- New rates from infrastructure replacement programs and base rate proceedings of $99.6 million.
- Higher revenues from the effects of colder weather in 2018 of $37.5 million.
- The effects of customer growth and increased usage of $17.4 million.
- Higher regulatory, tax and depreciation trackers, which are offset in operating expense, of $16.0 million.

Partially offset by:

- A revenue reserve of $85.0 million in 2018 resulting from the probable future refund of certain collections from customers as a result of the lower income tax rate from the TCJA.
- Decreased rates from implementation of regulatory outcomes related to the TCJA of $24.7 million.

Operating expenses were $867.3 million higher in 2018 compared to 2017. This change was primarily driven by:

- Expenses related to third-party claims and other costs following the Greater Lawrence Incident of $864.4 million, net of insurance recoveries recorded.
- Increased depreciation of $29.6 million due to regulatory outcomes of NIPSCO's gas rate case and higher capital expenditures placed in service.
- Higher regulatory, tax and depreciation trackers, which are offset in net revenues, of $16.0 million.
- Increased property taxes of $11.0 million due to higher capital expenditures placed in service and the impact of regulatory-driven property tax deferrals.

Partially offset by:

- Decreased outside services of $33.2 million primarily due to IT service provider transition and other strategic initiative costs in 2017, lower ongoing IT costs and a temporary shift of resources to the Greater Lawrence Incident restoration.
- Lower employee and administrative expenses of $30.2 million driven by reduced incentive compensation and a temporary shift of resources to the Greater Lawrence Incident restoration.

2017 vs. 2016 Operating Income

For 2017, Gas Distribution Operations reported operating income of $550.1 million, a decrease of $19.6 million from the comparable 2016 period.

Net revenues for 2017 were $2,097.1 million, an increase of $161.9 million from the same period in 2016. The change in net revenues was primarily driven by:

- New rates from base-rate proceedings and infrastructure replacement programs of $124.2 million.
- Higher regulatory, tax and depreciation trackers, which are offset in operating expense, of $26.9 million.
- The effects of increased customer growth of $10.3 million.
- Higher revenues from increased industrial usage of $5.8 million.

Operating expenses were $181.5 million higher in 2017 compared to 2016. This change was primarily driven by:

- Increased employee and administrative expenses of $53.4 million.
- Higher outside service costs of $52.8 million due to IT service provider transition costs, increased spend on strategic initiatives to enhance safety, reliability and customer value and higher pipeline maintenance expenses.
- Increased regulatory, tax and depreciation trackers, which are offset in net revenues, of $26.9 million.
- Higher depreciation of $15.2 million due to increased capital expenditures placed in service.

NISOURCE INC.
Gas Distribution Operations (continued)

- Increased property taxes of $8.1 million due to higher capital expenditures placed in service and an accrual adjustment recorded in 2016.
- Higher environmental costs of $4.7 million.
- Increased materials and supplies expenses of $3.4 million from maintenance-related activities.

Weather
In general, we calculate the weather-related revenue variance based on changing customer demand driven by weather variance from normal heating degree days. Our composite heating degree days reported do not directly correlate to the weather-related dollar impact on the results of Gas Distribution Operations. Heating degree days experienced during different times of the year or in different operating locations may have more or less impact on volume and dollars depending on when and where they occur. When the detailed results are combined for reporting, there may be weather-related dollar impacts on operations when there is not an apparent or significant change in our aggregated composite heating degree day comparison.

Weather in the Gas Distribution Operations service territories for 2018 was about 1% warmer than normal and about 13% colder than 2017, increasing net revenues $37.5 million for the year ended December 31, 2018 compared to 2017.

Weather in the Gas Distribution Operations service territories for 2017 was about 12% warmer than normal and about 4% warmer than 2016, decreasing net revenues $1.7 million for the year ended December 31, 2017 compared to 2016.

Throughput
Total volumes sold and transported for the year ended December 31, 2018 were 1,053.6 MMDth, compared to 973.2 MMDth for 2017. This increase is primarily attributable to colder weather experienced in 2018 compared to 2017.

Total volumes sold and transported for the year ended December 31, 2017 were 973.2 MMDth, compared to 971.7 MMDth for 2016.

Economic Conditions
All of our Gas Distribution Operations companies have state-approved recovery mechanisms that provide a means for full recovery of prudently incurred gas costs. Gas costs are treated as pass-through costs and have no impact on the net revenues recorded in the period. The gas costs included in revenues are matched with the gas cost expense recorded in the period and the difference is recorded on the Consolidated Balance Sheets as under-recovered or over-recovered gas cost to be included in future customer billings.

Certain Gas Distribution Operations companies continue to offer choice opportunities, where customers can choose to purchase gas from a third-party supplier, through regulatory initiatives in their respective jurisdictions. These programs serve to further reduce our exposure to gas prices.

Greater Lawrence Incident
Refer to Note 18-C. "Legal Proceedings," and E. "Other Matters," in the Notes to Consolidated Financial Statements, "Summary of Consolidated Financial Results,""Liquidity and Capital Resources" in this Management's Discussion, and Part I. Item 1A. "Risk Factors" for additional information related to the Greater Lawrence Incident.

NISOURCE INC.
Electric Operations

For the years ended December 31, 2018, 2017 and 2016, operating income and a reconciliation of net revenues to the most directly comparable GAAP measure, operating income, was as follows:

Year Ended December 31, *(in millions)*	**2018**	2017	2016	2018 vs. 2017	2017 vs. 2016
Operating Income	**$ 386.1**	$ 367.4	$ 301.3	$ 18.7	$ 66.1

Year Ended December 31, *(dollars in millions)*	**2018**	2017	2016	2018 vs. 2017	2017 vs. 2016
Net Revenues					
Operating revenues	**$ 1,708.2**	$ 1,786.5	$ 1,661.6	$ (78.3)	$ 124.9
Less: Cost of sales (excluding depreciation and amortization)	**502.1**	513.9	495.0	(11.8)	18.9
Net Revenues	**1,206.1**	1,272.6	1,166.6	(66.5)	106.0
Operating Expenses					
Operation and maintenance	**500.0**	565.6	528.9	(65.6)	36.7
Depreciation and amortization	**262.9**	277.8	274.5	(14.9)	3.3
Loss on sale of assets	**—**	1.9	—	(1.9)	1.9
Other taxes	**57.1**	59.9	61.9	(2.8)	(2.0)
Total Operating Expenses	**820.0**	905.2	865.3	(85.2)	39.9
Operating Income	**$ 386.1**	$ 367.4	$ 301.3	$ 18.7	$ 66.1
Revenues					
Residential	**$ 494.7**	$ 476.9	$ 457.4	$ 17.8	$ 19.5
Commercial	**492.6**	501.2	456.6	(8.6)	44.6
Industrial	**614.4**	698.1	631.6	(83.7)	66.5
Wholesale	**15.7**	11.6	11.6	4.1	—
Other	**90.8**	98.7	104.4	(7.9)	(5.7)
Total	**$ 1,708.2**	$ 1,786.5	$ 1,661.6	$ (78.3)	$ 124.9
Sales (Gigawatt Hours)					
Residential	**3,535.2**	3,301.7	3,514.8	233.5	(213.1)
Commercial	**3,844.6**	3,793.5	3,878.7	51.1	(85.2)
Industrial	**8,829.5**	9,469.7	9,281.8	(640.2)	187.9
Wholesale	**114.3**	32.5	19.0	81.8	13.5
Other	**124.4**	128.2	136.9	(3.8)	(8.7)
Total	**16,448.0**	16,725.6	16,831.2	(277.6)	(105.6)
Cooling Degree Days	**1,180**	837	988	343	(151)
Normal Cooling Degree Days	**806**	806	806	—	—
% Warmer than Normal	**46%**	4%	23%		
Electric Customers					
Residential	**412,267**	409,401	407,268	2,866	2,133
Commercial	**56,605**	56,134	55,605	471	529
Industrial	**2,284**	2,305	2,313	(21)	(8)
Wholesale	**735**	739	744	(4)	(5)
Other	**2**	2	2	—	—
Total	**471,893**	468,581	465,932	3,312	2,649

NISOURCE INC.
Electric Operations (continued)

Comparability of line item operating results may be impacted by regulatory and depreciation trackers (other than those for cost of sales) that allow for the recovery in rates of certain costs. Therefore, increases in these tracked operating expenses are offset by increases in net revenues and have essentially no impact on net income.

2018 vs. 2017 Operating Income
For 2018, Electric Operations reported operating income of $386.1 million, an increase of $18.7 million from the comparable 2017 period.

Net revenues for 2018 were $1,206.1 million, a decrease of $66.5 million from the same period in 2017. The change in net revenues was primarily driven by:

- Lower regulatory and depreciation trackers, which are offset in operating expense, of $35.6 million.
- Decreased rates from implementation of regulatory outcomes related to the TCJA of $32.9 million.
- Decreased industrial usage of $17.1 million.
- A revenue reserve of $16.2 million in 2018 resulting from the probable future refund of certain collections from customers as a result of the lower income tax rate from the TCJA .
- Increased fuel handling costs of $7.3 million.

Partially offset by:

- The effects of warmer weather of $25.2 million.
- Increased rates from infrastructure replacement programs of $18.6 million.

Operating expenses were $85.2 million lower in 2018 than 2017. This change was primarily driven by:

- Lower regulatory and depreciation trackers, which are offset in net revenues, of $35.6 million.
- Lower outside service costs of $32.1 million and lower material and supplies costs of $10.2 million primarily related to the retirement of Bailly Generating Station Units 7 and 8 on May 31, 2018.
- Decreased employee and administrative costs of $18.4 million.

Partially offset by:

- Increased depreciation of $10.0 million due to higher capital expenditures placed in service.

2017 vs. 2016 Operating Income
For 2017, Electric Operations reported operating income of $367.4 million, an increase of $66.1 million from the comparable 2016 period.

Net revenues for 2017 were $1,272.6 million, an increase of $106.0 million from the same period in 2016. The change in net revenues was primarily driven by:

- New rates from base-rate proceedings of $63.6 million.
- Increased rates from incremental capital spend on electric transmission projects of $24.2 million.
- Higher regulatory and depreciation trackers, which are offset in operating expense, of $18.0 million.
- New rates from infrastructure replacement programs of $6.0 million.
- The effects of increased customer count of $3.4 million.

Partially offset by:

- The effects of cooler weather of $16.1 million.

Operating expenses were $39.9 million higher in 2017 than 2016. This change was primarily driven by:

- Higher outside service costs of $20.1 million, primarily due to increased spend on strategic initiatives to enhance safety, reliability and customer value, generation-related maintenance, IT service provider transition costs and vegetation management activities.
- Higher employee and administrative costs of $19.2 million.
- Increased regulatory and depreciation trackers, which are offset in net revenues, of $18.0 million.

NISOURCE INC.
Electric Operations (continued)

- Increased depreciation of $5.6 million due to higher capital expenditures placed in service.
- Higher materials and supplies costs of $4.5 million driven by generation-related maintenance.

Partially offset by:

- Plant retirement costs of $22.1 million in 2016.
- Decreased amortization of regulatory assets of $10.8 million.

Weather
In general, we calculate the weather-related revenue variance based on changing customer demand driven by weather variance from normal heating or cooling degree days. Our composite heating or cooling degree days reported do not directly correlate to the weather-related dollar impact on the results of Electric Operations. Heating or cooling degree days experienced during different times of the year may have more or less impact on volume and dollars depending on when they occur. When the detailed results are combined for reporting, there may be weather-related dollar impacts on operations when there is not an apparent or significant change in our aggregated composite heating or cooling degree day comparison

Weather in the Electric Operations’ territories for 2018 was 46% warmer than normal and 41% warmer than the same period in 2017, increasing net revenues $25.2 million for the year ended December 31, 2018 compared to 2017.

Weather in the Electric Operations’ territories for 2017 was 4% warmer than normal and 15% cooler than the same period in 2016, decreasing net revenues $16.1 million for the year ended December 31, 2017 compared to 2016.

Sales
Electric Operations sales were 16,448.0 GWh for 2018, a decrease of 277.6 GWh, or 1.7% compared to 2017. This decrease was primarily attributable to higher internal generation from large industrial customers in 2018, partially offset by increased volumes for residential and commercial customers resulting from warmer weather.

Electric Operations sales were 16,725.6 GWh for 2017, a decrease of 105.6 GWh, or 0.6% compared to 2016.

BP Products North America. On March 29, 2018, WCE, which is currently owned by BP p.l.c ("BP") and BP Products North America, which operates the BP Refinery, filed a petition at the IURC asking that the combined operations of WCE and BP be treated as a single premise, and the WCE generation be dedicated primarily to BP Refinery operations beginning in May 2019 as WCE has self-certified as a qualifying facility at FERC. BP Refinery plans to continue to purchase electric service from NIPSCO at a reduced demand level beginning May 2019. Refer to Note 8, "Regulatory Matters," in the Notes to Consolidated Financial Statements for additional information.

Economic Conditions
NIPSCO has a state-approved recovery mechanism that provides a means for full recovery of prudently incurred fuel costs. Fuel costs are treated as pass-through costs and have no impact on the net revenues recorded in the period. The fuel costs included in revenues are matched with the fuel cost expense recorded in the period and the difference is recorded on the Consolidated Balance Sheets as under-recovered or over-recovered fuel cost to be included in future customer billings.

NIPSCO's performance remains closely linked to the performance of the steel industry. NIPSCO’s MWh sales to steel-related industries accounted for approximately 49.67% and 54.5% of the total industrial MWh sales for the years ended December 31, 2018 and 2017, respectively.

Electric Supply
Bailly Generating Station. NIPSCO completed the retirement of Units 7 and 8 at Bailly Generating Station on May 31, 2018. These units had a generating capacity of approximately 460 MW. The remaining net book value of the retired units is presented in "Regulatory assets (noncurrent)" on the Consolidated Balance Sheets. This balance continues to be amortized at a rate consistent with its inclusion in customer rates. The ongoing recovery of our remaining investment in these units will be addressed in NIPSCO's rate case filed on October 31, 2018. Refer to Note 8, "Regulatory Matters," and Note 18-E, "Other Matters," in the Notes to Consolidated Financial Statements for additional information.

NIPSCO 2018 Integrated Resource Plan. Multiple factors, but primarily economic ones, including low natural gas prices, advancing cost effective renewable technology and increasing capital and operating costs associated with existing coal plants, have led

NISOURCE INC.
Electric Operations (continued)

NIPSCO to conclude in its October 2018 Integrated Resource Plan submission that NIPSCO’s current fleet of coal generation facilities will be retired earlier than previous Integrated Resource Plan’s had indicated.

The Integrated Resource Plan evaluated demand-side and supply-side resource alternatives to reliably and cost effectively meet NIPSCO customers' future energy requirements over the ensuing 20 years. The preferred option within the Integrated Resource Plan retires R.M. Schahfer Generating Station (Units 14, 15, 17, and 18) by 2023 and Michigan City Generating Station (Unit 12) by 2028. These units represent 2,080 MW of generating capacity, equal to 72% of NIPSCO’s remaining capacity after the retirement of Bailly Units 7 and 8 in May of 2018.

The current replacement plan includes renewable sources of energy, including wind, solar, and battery storage to be obtained through a combination of NIPSCO ownership and PPAs. Refer to Note 18-E, "Other Matters," in the Notes to Consolidated Financial Statements for further discussion.

Liquidity and Capital Resources

Greater Lawrence Incident: As discussed in the "Executive Summary" and Note 18, "Other Commitments and Contingencies," we have recorded losses associated with the Greater Lawrence Incident and have invested capital to replace the entire affected 45-mile cast iron and bare steel pipeline system that delivers gas to the impacted area. As discussed in the Executive Summary and Note 18 referenced earlier in this paragraph, and Part I, Item 1A "Risk Factors," in this report, we may incur additional expenses and liabilities in excess of our recorded liabilities and estimated additional costs associated with the Greater Lawrence Incident. The timing and amount of future financing needs arising from the Greater Lawrence Incident, if any, will depend on the ultimate timing and amount of payments made in connection with the Greater Lawrence Incident and the timing and amount of associated insurance recoveries. Through income generated from operating activities, amounts available under our short-term revolving credit facility, commercial paper program, accounts receivable securitization facilities, term loan borrowings, long-term debt agreements and our ability to access the capital markets, we believe there is adequate capital available to fund these expenditures.

Operating Activities
Net cash from operating activities for the year ended December 31, 2018 was $540.1 million, a decrease of $202.1 million from 2017. This decrease was driven by cash spend for the Greater Lawrence Incident in 2018 offset by decreased pension plan contributions as discussed below as well as decreased operation and maintenance expenses (excluding expenses related to the Greater Lawrence Incident). The decrease in cash from operations was further offset by higher sales due to colder weather during the 2018 winter heating season compared to 2017 and increased rates from infrastructure replacement programs and rate case outcomes.

Greater Lawrence Incident. During 2018, we paid approximately $731 million in operating cash flow related to the Greater Lawrence Incident. Refer to Note 18-E "Other Matters" for further information.

Pension and Other Postretirement Plan Funding. In 2017, we contributed $282.3 million to our pension plans (including a $277 million discretionary contribution made during the third quarter of 2017) and $31.6 million to our other postretirement benefit plans.

In 2018, we contributed $2.9 million to our pension plans and $21.0 million to our other postretirement benefit plans. Given the current funded status of the pension plans, and barring unforeseen market volatility that may negatively impact the valuation of our plan assets, we do not believe additional material contributions to our pension plans will be required for the foreseeable future.

Income Taxes. Rates for our regulated customers include provisions for the collection of U.S. federal income taxes. The reduction in the U.S. federal corporate income tax rate as a result of the TCJA has led to a decrease in the amount billed to customers through rates, ultimately resulting in lower cash collections from operating activities. As discussed in further detail in Note 7, "Regulatory Matters," in the Notes to the Consolidated Financial Statements, our regulated subsidiaries are engaged with the relevant state utility commissions to address the impacts of the TCJA on future customer rates. During 2018, billings to customers decreased approximately $57.6 million compared to the same period in 2017 as a result of adjustments to certain rates in our Kentucky, Ohio, Maryland, Pennsylvania, Massachusetts and Indiana jurisdictions. Additionally, during 2018, we recorded additional TCJA-related regulatory liabilities related to 2018 collections from customers, which are being refunded back to customers once new customer rates are approved by our regulators.

In addition, we will be required to pass back to customers "excess deferred taxes" which represent amounts collected from customers in the past to cover deferred tax liabilities which, as a result of the passage of the TCJA, are now less than the originally billed amounts. Approximately $1.5 billion of excess deferred taxes was recorded to "Regulatory liabilities (noncurrent)" on the Consolidated Balance Sheets as of December 31, 2017 as a result of implementing the TCJA. The majority of this balance related to temporary book-to-tax differences on utility property protected by IRS normalization rules. As modified rates are approved by each of our regulators, we expect this portion of the balance will be passed back to customers over the remaining average useful life of the associated property as required by the TCJA. The pass back period for the remainder of this balance will be determined by our state utility commissions in future proceedings. Our estimate of the amount and pass-back period of excess deferred taxes is subject to change pending final review by the utility commissions of the states in which we operate. As noted above, this pass back of excess deferred taxes has already begun in certain of our jurisdictions. As of December 31, 2018 we have approximately $1.4 billion of remaining regulatory liabilities associated with excess deferred taxes. See Note 8, "Regulatory Matters," for additional information.

As of December 31, 2018, we had a recorded deferred tax asset of $759.6 million related to a federal NOL carryforward, of which $508.5 million relates to years prior to the implementation of the TCJA. As a result of being in an NOL position, we were not required to make any cash payments for federal income tax purposes during the three years ended December 31, 2018. The carryforward periods for pre-TCJA tax benefits expire in various tax years from 2028 to 2037, however, we expect to fully utilize the carryforward benefit prior to its expiration. Per the TCJA, utilization of NOL carryforwards generated after December 31, 2017 do not expire, but are limited to 80% of current year taxable income. Accordingly, we may be required to make cash payments for federal income taxes in future years despite having NOL carryforwards in excess of current taxes payable.

Investing Activities

Our cash used for investing activities varies year over year primarily as a result of changes in the level of annual capital expenditures. The table below reflects capital expenditures and certain other investing activities by segment for 2018, 2017 and 2016.

(in millions)	**2018**	2017	2016
Gas Distribution Operations			
System Growth and Tracker	**$ 1,073.7**	$ 909.2	$ 835.0
Maintenance	**241.6**	216.4	219.4
Total Gas Distribution Operations	**1,315.3**	1,125.6	1,054.4
Electric Operations			
System Growth and Tracker	**346.0**	435.3	314.1
Maintenance	**153.3**	157.1	106.5
Total Electric Operations	**499.3**	592.4	420.6
Corporate and Other Operations - Maintenance[1]	**—**	35.8	15.4
Total[2]	**$ 1,814.6**	$ 1,753.8	$ 1,490.4

[1]Zero Corporate and Other capital expenditures in 2018 driven by the leasing of IT assets beginning in Q1 2018 versus historical practice of purchasing.

[2]Amounts differ from those presented on the Statements of Consolidated Cash Flows primarily due to the capitalized portion of the Corporate Incentive Plan payout, inclusion of capital expenditures included in current liabilities and AFUDC Equity.

For 2018, capital expenditures and certain other investing activities were $1,814.6 million, which was $60.8 million higher than the 2017 capital program. This increased spending is due in part to costs associated with the Greater Lawrence Incident pipeline replacement, gas transmission projects, environmental investments and system modernization projects.

For 2017, capital expenditures and certain other investing activities were $1,753.8 million, which was $263.4 million higher than the 2016 capital program. This increased spending is mainly due to electric transmission projects, environmental investments and system modernization projects.

For 2019, we project to invest approximately $1.6 to $1.7 billion in our capital program. This projected level of spend is consistent with 2018 spend levels and is expected to focus primarily on the continuation of the modernization projects, segment growth across the Gas Distribution Operations segment, and TDSIC spend.

Financing Activities

Short-term Debt. Refer to Note 15, "Short-Term Borrowings," in the Notes to Consolidated Financial Statements for information on short-term debt.

Long-term Debt. Refer to Note 14, "Long-Term Debt," in the Notes to Consolidated Financial Statements for information on long-term debt.

Net Available Liquidity. As of December 31, 2018, an aggregate of $974.6 million of net liquidity was available, including cash and credit available under the revolving credit facility and accounts receivable securitization programs.

The following table displays NiSource's liquidity position as of December 31, 2018 and 2017:

Year Ended December 31, *(in millions)*	2018	2017
Current Liquidity		
Revolving Credit Facility	**$ 1,850.0**	$ 1,850.0
Accounts Receivable Program[1]	**399.2**	336.7
Less:		
Commercial Paper	**978.0**	869.0
Accounts Receivable Program Utilized	**399.2**	336.7
Letters of Credit Outstanding Under Credit Facility	**10.2**	11.1
Add:		
Cash and Cash Equivalents	**112.8**	29.0
Net Available Liquidity	**$ 974.6**	$ 998.9

[1]Represents the lesser of the seasonal limit or maximum borrowings supportable by the underlying receivables.

Debt Covenants. We are subject to a financial covenant under our revolving credit facility and term loan agreement, which requires us to maintain a debt to capitalization ratio that does not exceed 70%. A similar covenant in a 2005 private placement note purchase agreement requires us to maintain a debt to capitalization ratio that does not exceed 75%. As of December 31, 2018, the ratio was 61.4%.

Sale of Trade Accounts Receivables. Refer to Note 17, “Transfers of Financial Assets,” in the Notes to Consolidated Financial Statements for information on the sale of trade accounts receivable.

Credit Ratings. The credit rating agencies periodically review our ratings, taking into account factors such as our capital structure and earnings profile. The following table includes our and certain of our subsidiaries' credit ratings and ratings outlook as of December 31, 2018.

A credit rating is not a recommendation to buy, sell or hold securities, and may be subject to revision or withdrawal at any time by the assigning rating organization.

	S&P		Moody's		Fitch	
	Rating	Outlook	Rating	Outlook	Rating	Outlook
NiSource	BBB+	Negative	Baa2	Stable	BBB	Stable
NIPSCO	BBB+	Negative	Baa1	Stable	BBB	Stable
Columbia of Massachusetts	BBB+	Negative	Baa2	Stable	Not rated	Not rated
Commercial Paper	A-2	Negative	P-2	Stable	F2	Stable

Certain of our subsidiaries have agreements that contain “ratings triggers” that require increased collateral if our credit ratings or the credit ratings of certain of our subsidiaries are below investment grade. These agreements are primarily for insurance purposes and for the physical purchase or sale of power. As of December 31, 2018, the collateral requirement that would be required in the event of a downgrade below the ratings trigger levels would amount to approximately $53.8 million. In addition to agreements with ratings triggers, there are other agreements that contain “adequate assurance” or “material adverse change” provisions that could necessitate additional credit support such as letters of credit and cash collateral to transact business.

Equity. Our authorized capital stock consists of 420,000,000 shares, $0.01 par value, of which 400,000,000 are common stock and 20,000,000 are preferred stock. As of December 31, 2018, 372,363,656 shares of common stock and 420,000 shares of preferred stock were outstanding. For more information regarding our common and preferred stock, see Note 12, "Equity," in the Notes to Consolidated Financial Statements.

Contractual Obligations. We have certain contractual obligations requiring payments at specified periods. The obligations include long-term debt, lease obligations, energy commodity contracts and obligations for various services including pipeline capacity and outsourcing of IT services. The total contractual obligations in existence at December 31, 2018 and their maturities were:

(in millions)	Total	2019	2020	2021	2022	2023	After
Long-term debt [1]	$ 7,029.6	$ 41.0	$ —	$ 63.6	$ 530.0	$ 600.0	$ 5,795.0
Capital leases[2]	322.4	23.0	22.5	22.6	22.1	19.8	212.4
Interest payments on long-term debt	6,311.7	319.8	318.6	318.6	315.0	289.0	4,750.7
Operating leases[3]	45.9	11.0	7.3	6.1	4.2	2.8	14.5
Energy commodity contracts	154.3	99.2	55.1	—	—	—	—
Service obligations:							
Pipeline service obligations	3,566.7	592.3	487.7	450.5	437.5	260.8	1,337.9
IT service obligations	211.0	68.3	60.0	47.1	35.6	—	—
Other service obligations	86.7	33.5	43.6	9.6	—	—	—
Other liabilities	24.2	24.2	—	—	—	—	—
Total contractual obligations	$ 17,752.5	$ 1,212.3	$ 994.8	$ 918.1	$ 1,344.4	$ 1,172.4	$ 12,110.5

[1] Long-term debt balance excludes unamortized issuance costs and discounts of $68.5 million.
[2] Capital lease payments shown above are inclusive of interest totaling $114.6 million.
[3] Operating lease balances do not include amounts for fleet leases that can be renewed beyond the initial lease term. The Company anticipates renewing the leases beyond the initial term, but the anticipated payments associated with the renewals do not meet the definition of expected minimum lease payments and therefore are not included above. Expected payments are $26.7 million in 2019, $22.4 million in 2020, $16.6 million in 2021, $12.3 million in 2022, $9.3 million in 2023 and $8.8 million thereafter.

Our calculated estimated interest payments for long-term debt is based on the stated coupon and payment dates. For 2019, we project that we will be required to make interest payments of approximately $363.1 million, which includes $319.8 million of interest payments related to our long-term debt outstanding as of December 31, 2018. At December 31, 2018, we had $1,977.2 million in short-term borrowings outstanding.

Our expected payments included within "Other liabilities" in the table of contractual commitments above contains employer contributions to pension and other postretirement benefits plans expected to be made in 2019. Plan contributions beyond 2019 are dependent upon a number of factors, including actual returns on plan assets, which cannot be reliably estimated at this time. In 2019, we expect to make contributions of approximately $3.0 million to our pension plans and approximately $20.6 million to our postretirement medical and life plans. Refer to Note 11, "Pension and Other Postretirement Benefits," in the Notes to Consolidated Financial Statements for more information.

We cannot reasonably estimate the settlement amounts or timing of cash flows related to long-term obligations classified as "Total Other Liabilities" on the Consolidated Balance Sheets, other than those described above.

We also have obligations associated with income, property, gross receipts, franchise, payroll, sales and use, and various other taxes and expect to make tax payments of approximately $240.6 million in 2019, which are not included in the table above.

Refer to Note 18-A, "Contractual Obligations," in the Notes to Consolidated Financial Statements for further information.

In January 2019, NIPSCO executed two 20 year PPAs to purchase 100% of the output from renewable generation facilities at a fixed price per mwh and a BTA with a developer to construct a renewable generation facility. Payments under these agreement are not included in the table above as these agreements were executed in 2019 and remain subject to approval by the relevant regulatory authorities before the deals would commence. See 18-E. "Other Matters - NIPSCO 2018 Integrated Resource Plan," for additional information.

Off-Balance Sheet Arrangements

We, along with certain of our subsidiaries, enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include guarantees and stand-by letters of credit.

Refer to Note 18, "Other Commitments and Contingencies," in the Notes to Consolidated Financial Statements for additional information about such arrangements.

Market Risk Disclosures

Risk is an inherent part of our businesses. The extent to which we properly and effectively identify, assess, monitor and manage each of the various types of risk involved in our businesses is critical to our profitability. We seek to identify, assess, monitor and manage, in accordance with defined policies and procedures, the following principal market risks that are involved in our businesses: commodity price risk, interest rate risk and credit risk. Risk management for us is a multi-faceted process with oversight by the Risk Management Committee that requires constant communication, judgment and knowledge of specialized products and markets. Our senior management takes an active role in the risk management process and has developed policies and procedures that require specific administrative and business functions to assist in the identification, assessment and control of various risks. These may include, but are not limited to market, operational, financial, compliance and strategic risk types. In recognition of the increasingly varied and complex nature of the energy business, our risk management process, policies and procedures continue to evolve and are subject to ongoing review and modification.

Commodity Price Risk
We are exposed to commodity price risk as a result of our subsidiaries' operations involving natural gas and power. To manage this market risk, our subsidiaries use derivatives, including commodity futures contracts, swaps, forwards and options. We do not participate in speculative energy trading activity.

Commodity price risk resulting from derivative activities at our rate-regulated subsidiaries is limited, since regulations allow recovery of prudently incurred purchased power, fuel and gas costs through the rate-making process, including gains or losses on these derivative instruments. If states should explore additional regulatory reform, these subsidiaries may begin providing services without the benefit of the traditional rate-making process and may be more exposed to commodity price risk.

Our subsidiaries are required to make cash margin deposits with their brokers to cover actual and potential losses in the value of outstanding exchange traded derivative contracts. The amount of these deposits, some of which is reflected in our restricted cash balance, may fluctuate significantly during periods of high volatility in the energy commodity markets.

Refer to Note 9, "Risk Management Activities," in the Notes to the Consolidated Financial Statements for further information on our commodity price risk assets and liabilities as of December 31, 2018 and 2017.

Interest Rate Risk
We are exposed to interest rate risk as a result of changes in interest rates on borrowings under our revolving credit agreement, commercial paper program, term loan borrowings and accounts receivable programs, which have interest rates that are indexed to short-term market interest rates. Based upon average borrowings and debt obligations subject to fluctuations in short-term market interest rates, an increase (or decrease) in short-term interest rates of 100 basis points (1%) would have increased (or decreased) interest expense by $13.3 million and $15.8 million for 2018 and 2017, respectively. We are also exposed to interest rate risk as a result of changes in benchmark rates that can influence the interest rates of future debt issuances.

Refer to Note 9, "Risk Management Activities," in the Notes to Consolidated Financial Statements for further information on our interest rate risk assets and liabilities as of December 31, 2018 and 2017.

Credit Risk
Due to the nature of the industry, credit risk is embedded in many of our business activities. Our extension of credit is governed by a Corporate Credit Risk Policy. In addition, Risk Management Committee guidelines are in place which document management approval levels for credit limits, evaluation of creditworthiness, and credit risk mitigation efforts. Exposures to credit risks are monitored by the risk management function which is independent of commercial operations. Credit risk arises due to the possibility that a customer, supplier or counterparty will not be able or willing to fulfill its obligations on a transaction on or before the settlement date. For derivative-related contracts, credit risk arises when counterparties are obligated to deliver or purchase defined commodity units of gas or power to us at a future date per execution of contractual terms and conditions. Exposure to credit risk is measured in terms of both current obligations and the market value of forward positions net of any posted collateral such as cash and letters of credit.

We closely monitor the financial status of our banking credit providers. We evaluate the financial status of our banking partners through the use of market-based metrics such as credit default swap pricing levels, and also through traditional credit ratings provided by major credit rating agencies.

Other Information

Critical Accounting Policies

We apply certain accounting policies based on the accounting requirements discussed below that have had, and may continue to have, significant impacts on our operations and Consolidated Financial Statements.

Basis of Accounting for Rate-Regulated Subsidiaries. ASC Topic 980, *Regulated Operations*, provides that rate-regulated subsidiaries account for and report assets and liabilities consistent with the economic effect of the way in which regulators establish rates, if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income are deferred on the Consolidated Balance Sheets and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. The total amounts of regulatory assets and liabilities reflected on the Consolidated Balance Sheets were $2,237.5 million and $2,660.0 million at December 31, 2018, and $1,801.2 million and $2,795.6 million at December 31, 2017, respectively. For additional information, refer to Note 8, "Regulatory Matters," in the Notes to Consolidated Financial Statements.

In the event that regulation significantly changes the opportunity for us to recover our costs in the future, all or a portion of our regulated operations may no longer meet the criteria for the application of ASC Topic 980, *Regulated Operations*. In such event, a write-down of all or a portion of our existing regulatory assets and liabilities could result. If transition cost recovery is approved by the appropriate regulatory bodies that would meet the requirements under GAAP for continued accounting as regulatory assets and liabilities during such recovery period, the regulatory assets and liabilities would be reported at the recoverable amounts. If we were unable to continue to apply the provisions of ASC Topic 980, *Regulated Operations*, we would be required to apply the provisions of ASC Topic 980-20, *Discontinuation of Rate-Regulated Accounting*. In management's opinion, our regulated subsidiaries will be subject to ASC Topic 980, *Regulated Operations* for the foreseeable future.

Certain of the regulatory assets reflected on our Consolidated Balance Sheets require specific regulatory action in order to be included in future service rates. Although recovery of these amounts is not guaranteed, we believe that these costs meet the requirements for deferral as regulatory assets. Regulatory assets requiring specific regulatory action amounted to $320.4 million at December 31, 2018. If we determine that the amounts included as regulatory assets were not recoverable, a charge to income would immediately be required to the extent of the unrecoverable amounts.

The passage of the TCJA into law necessitated the remeasurement of our deferred income tax balances to reflect the new U.S. corporate income tax rate of 21%. For our regulated entities, substantially all of the impact of this remeasurement was recorded to a regulatory asset or regulatory liability, as appropriate, until such time that we receive final regulatory orders prescribing the required accounting treatment and related impact on future customer rates. For additional information, refer to Note 10, "Income Taxes," in the Notes to Consolidated Financial Statements.

As discussed in Note 18-E, "Other Matters - Greater Lawrence Pipeline Replacement," we incurred approximately $167 million of capital spend for pipeline replacement in the affected communities during 2018. We estimate this replacement work will cost between $220 million and $230 million in total. Columbia of Massachusetts has provided notice to its property insurer of the Greater Lawrence Incident and discussions around the claim and recovery have commenced. The recovery of any capital investment not reimbursed through insurance will be addressed in a future regulatory proceeding. The outcome of such a proceeding is uncertain. In accordance with ASC 980-360, if it becomes probable that a portion of the pipeline replacement cost will not be recoverable through customer rates and an amount can be reasonably estimated, we will reduce our regulated plant balance for the amount of the probable disallowance and record an associated charge to earnings. This could result in a material adverse effect to our financial condition, results of operations and cash flows. Additionally, if a rate order is received allowing recovery of the investment with no or reduced return on investment, a loss on disallowance may be required.

Pension and Postretirement Benefits. We have defined benefit plans for both pension and other postretirement benefits. The calculation of the net obligations and annual expense related to the plans requires a significant degree of judgment regarding the discount rates to be used in bringing the liabilities to present value, expected long-term rates of return on plan assets, health care trend rates, and mortality rates, among other assumptions. Due to the size of the plans and the long-term nature of the associated liabilities, changes in the assumptions used in the actuarial estimates could have material impacts on the measurement of the net obligations and annual expense recognition. Differences between actuarial assumptions and actual plan results are deferred into AOCI or a regulatory balance sheet account, depending on the jurisdiction of our entity. These deferred gains or losses are then amortized into the income statement when the accumulated differences exceed 10% of the greater of the projected benefit obligation or the fair value of plan assets (known in GAAP as the "corridor" method) or when settlement accounting is triggered.

The discount rates, expected long-term rates of return on plan assets, health care cost trend rates and mortality rates are critical assumptions. Methods used to develop these assumptions are described below. While a third party actuarial firm assists with the development of many of these assumptions, we are ultimately responsible for selecting the final assumptions.

The discount rate is utilized principally in calculating the actuarial present value of pension and other postretirement benefit obligations and net periodic pension and other postretirement benefit plan costs. Our discount rates for both pension and other postretirement benefits are determined using spot rates along an AA-rated above median yield curve with cash flows matching the expected duration of benefit payments to be made to plan participants.

The expected long-term rate of return on plan assets is a component utilized in calculating annual pension and other postretirement benefit plan costs. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, target asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider the guidance from our investment advisors in making a final determination of our expected rate of return on assets.

For measurement of 2019 net periodic benefit cost, we selected an expected pre-tax long-term rate of return of 6.10% and 5.80% for our pension and other postretirement benefit plan assets, respectively.

We estimate the assumed health care cost trend rate, which is used in determining our other postretirement benefit net expense, based upon our actual health care cost experience, the effects of recently enacted legislation, third-party actuarial surveys and general economic conditions.

We use the Society of Actuaries' most recently published mortality data in developing a best estimate of mortality as part of the calculation of the pension and other postretirement benefit obligations.

The following tables illustrate the effects of changes in these actuarial assumptions while holding all other assumptions constant:

	Impact on December 31, 2018 Projected Benefit Obligation Increase/(Decrease)	
Change in Assumptions *(in millions)*	Pension Benefits	Other Postretirement Benefits
+50 basis points change in discount rate	$ (79.6)	$ (23.6)
-50 basis points change in discount rate	86.2	25.8
+50 basis points change in health care trend rates		12.5
-50 basis points change in health care trend rates		(11.0)

	Impact on 2018 Expense Increase/(Decrease)(1)	
Change in Assumptions *(in millions)*	Pension Benefits	Other Postretirement Benefits
+50 basis points change in discount rate	$ (3.3)	$ (0.7)
-50 basis points change in discount rate	2.8	0.8
+50 basis points change in expected long-term rate of return on plan assets	(10.3)	(1.3)
-50 basis points change in expected long-term rate of return on plan assets	10.3	1.3
+50 basis points change in health care trend rates		0.6
-50 basis points change in health care trend rates		(0.5)

(1)Before labor capitalization and regulatory deferrals.

In January 2017, we changed the method used to estimate the service and interest components of net periodic benefit cost for pension and other postretirement benefits. This change, compared to the previous method, resulted in a decrease in the actuarially-determined service and interest cost components. Historically, we estimated service and interest cost utilizing a single weighted-average discount rate derived from the yield curve used to measure the benefit obligation at the beginning of the period. For fiscal 2017 and beyond, we now utilize a full yield curve approach to estimate these components by applying the specific spot rates along the yield curve used in the determination of the benefit obligation to the relevant projected cash flows. For further discussion of our pension and other postretirement benefits, see Note 11, "Pension and Other Postretirement Benefits," in the Notes to Consolidated Financial Statements.

Goodwill. We have seven goodwill reporting units, comprised of the seven state operating companies within the Gas Distribution Operations reportable segment. Our goodwill assets at December 31, 2018 were $1,690.7 million, most of which resulted from the acquisition of Columbia on November 1, 2000.

As required by GAAP, we test for impairment of goodwill on an annual basis and on an interim basis when events or circumstances indicate that a potential impairment may exist. Our annual goodwill test takes place in the second quarter of each year and was most recently finalized as of May 1, 2018. In the third quarter of 2018, we determined the Greater Lawrence Incident represented a triggering event that required an impairment analysis of goodwill. The incident specifically impacts our Columbia of Massachusetts reporting unit. The quantitative impairment analysis as of September 30, 2018 determined the fair value of Columbia of Massachusetts reporting unit continued to exceed its carrying value. For additional information, refer to Note 6, "Goodwill and Other Intangible Assets," in the Notes to Consolidated Financial Statements.

We completed a quantitative ("step 1") fair value measurement of our reporting units during the May 1, 2016 goodwill test. Consistent with our historical impairment testing of goodwill, fair value of the reporting units was determined based on a weighting of income and market approaches. These approaches require significant judgments including appropriate long-term growth rates and discount rates for the income approach and appropriate multiples of earnings for peer companies and control premiums for the market approach. A qualitative ("step 0") test was completed on May 1, 2018. We assessed various assumptions, events and circumstances that would have affected the estimated fair value of the reporting units in our baseline May 1, 2016 test. The results of this assessment indicated that it is not more likely than not that its reporting unit fair values are less than the reporting unit carrying values and no impairments are necessary.

The discount rates were derived using peer company data compiled with the assistance of a third party valuation services firm. The discount rates used are subject to change based on changes in tax rates at both the state and federal level, debt and equity ratios at each reporting unit and general economic conditions.

The long-term growth rate was derived by evaluating historic growth rates, new business and investment opportunities beyond the near term horizon. The long-term growth rate is subject to change depending on inflationary impacts to the U.S. economy and the individual business environments in which each reporting unit operates.

The May 1, 2016 test indicated the fair value of each of the reporting units that carry or are allocated goodwill exceeded their carrying values, indicating that no impairment existed under the step 1 annual impairment test. If the estimates of free cash flow used in this step 1 analysis had been 10% lower, the resulting fair values would have still been greater than the carrying value for each of the reporting units tested, holding all other assumptions constant.

Revenue Recognition. Revenue is recorded as products and services are delivered. Utility revenues are billed to customers monthly on a cycle basis. Revenues are recorded on the accrual basis and include estimates for electricity and gas delivered but not billed.

We adopted the provisions of ASC 606 beginning on January 1, 2018 using a modified retrospective method, which was applied to all contracts. No material adjustments were made to January 1, 2018 opening balances and no material changes in the amount or timing of future revenue recognition occurred as a result of the adoption of ASC 606. Refer to Note 3 "Revenue Recognition," in the Notes to Consolidated Financial Statements.

Recently Issued Accounting Pronouncements

Refer to Note 2, "Recent Accounting Pronouncements," in the Notes to Consolidated Financial Statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Quantitative and Qualitative Disclosures about Market Risk are reported in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Market Risk Disclosures."

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

NISOURCE INC.

NISOURCE INC.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of NiSource Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of NiSource Inc. and subsidiaries (the "Company") as of December 31, 2018 and 2017, the related statements of consolidated income (loss), comprehensive income (loss), stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2018, and the related notes and the schedule listed in the Index at item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 20, 2019, expressed an unqualified opinion on the Company's internal control over financial reporting.

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 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. 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
Columbus, Ohio
February 20, 2019

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of NiSource Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of NiSource Inc. and subsidiaries (the "Company") as of December 31, 2018, 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 Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the financial statements as of and for year ended December 31, 2018, of the Company and our report dated February 20, 2019, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible 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. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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
Columbus, Ohio
February 20, 2019

NISOURCE INC.
STATEMENTS OF CONSOLIDATED INCOME (LOSS)

Year Ended December 31, *(in millions, except per share amounts)*	**2018**	2017	2016
Operating Revenues			
Customer revenues	**$ 4,991.1**	$ 4,730.2	$ 4,392.5
Other revenues	**123.4**	144.4	100.0
Total Operating Revenues	**5,114.5**	4,874.6	4,492.5
Operating Expenses			
Cost of sales (excluding depreciation and amortization)	**1,761.3**	1,518.7	1,390.2
Operation and maintenance	**2,352.9**	1,601.7	1,445.8
Depreciation and amortization	**599.6**	570.3	547.1
Loss (Gain) on sale of assets and impairments, net	**1.2**	5.5	(1.0)
Other taxes	**274.8**	257.2	244.3
Total Operating Expenses	**4,989.8**	3,953.4	3,626.4
Operating Income	**124.7**	921.2	866.1
Other Income (Deductions)			
Interest expense, net	**(353.3)**	(353.2)	(349.5)
Other, net	**43.5**	(13.5)	(3.0)
Loss on early extinguishment of long-term debt	**(45.5)**	(111.5)	—
Total Other Deductions, Net	**(355.3)**	(478.2)	(352.5)
Income (Loss) before Income Taxes	**(230.6)**	443.0	513.6
Income Taxes	**(180.0)**	314.5	182.1
Net Income (Loss)	**(50.6)**	128.5	331.5
Preferred dividends	**(15.0)**	—	—
Net Income (Loss) Available to Common Shareholders	**(65.6)**	128.5	331.5
Earnings (Loss) Per Share			
Basic Earnings (Loss) Per Share	**$ (0.18)**	$ 0.39	$ 1.03
Diluted Earnings (Loss) Per Share	**$ (0.18)**	$ 0.39	$ 1.02
Basic Average Common Shares Outstanding	**356.5**	329.4	321.8
Diluted Average Common Shares	**356.5**	330.8	323.5

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NISOURCE INC.
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME (LOSS)

Year Ended December 31, *(in millions, net of taxes)*	**2018**	2017	2016
Net Income (Loss)	**$ (50.6)**	$ 128.5	$ 331.5
Other comprehensive income (loss):			
Net unrealized gain (loss) on available-for-sale securities(1)	**(2.6)**	0.8	(0.1)
Net unrealized gain (loss) on cash flow hedges(2)	**22.7**	(22.5)	8.6
Unrecognized pension and OPEB benefit (costs)(3)	**(4.4)**	3.4	1.5
Total other comprehensive income (loss)	**15.7**	(18.3)	10.0
Total Comprehensive Income	**$ (34.9)**	$ 110.2	$ 341.5

(1) Net unrealized gain (loss) on available-for-sale securities, net of $0.6 million tax benefit, $0.4 million tax expense and $0.1 million tax benefit in 2018, 2017 and 2016, respectively.
(2) Net unrealized gain (loss) on derivatives qualifying as cash flow hedges, net of $7.5 million tax expense, $13.9 million tax benefit and $5.6 million tax expense in 2018, 2017 and 2016, respectively.
(3) Unrecognized pension and OPEB benefit (costs), net of $1.5 million tax benefit, $2.1 million tax expense and $0.1 million tax expense in 2018, 2017 and 2016, respectively.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NISOURCE INC.
CONSOLIDATED BALANCE SHEETS

(in millions)	**December 31, 2018**	December 31, 2017
ASSETS		
Property, Plant and Equipment		
Utility plant	**$ 22,780.8**	$ 21,026.6
Accumulated depreciation and amortization	**(7,257.9)**	(6,953.6)
Net utility plant	**15,522.9**	14,073.0
Other property, at cost, less accumulated depreciation	**19.6**	286.5
Net Property, Plant and Equipment	**15,542.5**	14,359.5
Investments and Other Assets		
Unconsolidated affiliates	**2.1**	5.5
Other investments	**204.0**	204.1
Total Investments and Other Assets	**206.1**	209.6
Current Assets		
Cash and cash equivalents	**112.8**	29.0
Restricted cash	**8.3**	9.4
Accounts receivable (less reserve of $21.1 and $18.3, respectively)	**1,058.5**	898.9
Gas inventory	**286.8**	285.1
Materials and supplies, at average cost	**101.0**	105.9
Electric production fuel, at average cost	**34.7**	80.1
Exchange gas receivable	**88.4**	45.8
Regulatory assets	**235.4**	176.3
Prepayments and other	**129.5**	132.8
Total Current Assets	**2,055.4**	1,763.3
Other Assets		
Regulatory assets	**2,002.1**	1,624.9
Goodwill	**1,690.7**	1,690.7
Intangible assets, net	**220.7**	231.7
Deferred charges and other	**86.5**	82.0
Total Other Assets	**4,000.0**	3,629.3
Total Assets	**$ 21,804.0**	$ 19,961.7

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

NISOURCE INC.
CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)	**December 31, 2018**	December 31, 2017
CAPITALIZATION AND LIABILITIES		
Capitalization		
Stockholders' Equity		
Common stock - $0.01 par value, 400,000,000 shares authorized; 372,363,656 and 337,015,806 shares outstanding, respectively	**$ 3.8**	$ 3.4
Preferred stock - $0.01 par value, 20,000,000 shares authorized; 420,000 shares outstanding	**880.0**	—
Treasury stock	**(99.9)**	(95.9)
Additional paid-in capital	**6,403.5**	5,529.1
Retained deficit	**(1,399.3)**	(1,073.1)
Accumulated other comprehensive loss	**(37.2)**	(43.4)
Total Stockholders' Equity	**5,750.9**	4,320.1
Long-term debt, excluding amounts due within one year	**7,105.4**	7,512.2
Total Capitalization	**12,856.3**	11,832.3
Current Liabilities		
Current portion of long-term debt	**50.0**	284.3
Short-term borrowings	**1,977.2**	1,205.7
Accounts payable	**883.8**	625.6
Customer deposits and credits	**238.9**	262.6
Taxes accrued	**222.7**	208.1
Interest accrued	**90.7**	112.3
Risk management liabilities	**5.0**	43.2
Exchange gas payable	**85.5**	59.6
Regulatory liabilities	**140.9**	58.7
Legal and environmental	**18.9**	32.1
Accrued compensation and employee benefits	**149.7**	195.4
Claims accrued	**114.7**	12.5
Other accruals	**58.8**	78.3
Total Current Liabilities	**4,036.8**	3,178.4
Other Liabilities		
Risk management liabilities	**46.7**	28.5
Deferred income taxes	**1,330.5**	1,292.9
Deferred investment tax credits	**11.2**	12.4
Accrued insurance liabilities	**84.4**	80.1
Accrued liability for postretirement and postemployment benefits	**389.1**	337.1
Regulatory liabilities	**2,519.1**	2,736.9
Asset retirement obligations	**352.0**	268.7
Other noncurrent liabilities	**177.9**	194.4
Total Other Liabilities	**4,910.9**	4,951.0
Commitments and Contingencies (Refer to Note 18, "Other Commitments and Contingencies")	**—**	—
Total Capitalization and Liabilities	**$ 21,804.0**	$ 19,961.7

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NISOURCE INC.
STATEMENTS OF CONSOLIDATED CASH FLOWS

Year Ended December 31, (in millions)	2018	2017	2016
Operating Activities			
Net Income (Loss)	$ (50.6)	$ 128.5	$ 331.5
Adjustments to Reconcile Net Income (Loss) to Net Cash from Operating Actvities:			
Loss on early extinguishment of debt	45.5	111.5	—
Depreciation and amortization	599.6	570.3	547.1
Deferred income taxes and investment tax credits	(188.2)	306.7	182.3
Stock compensation expense and 401(k) profit sharing contribution	28.6	40.1	46.5
Amortization of discount/premium on debt	7.5	7.4	7.6
AFUDC equity	(14.2)	(12.6)	(11.6)
Other adjustments	1.7	6.6	(7.2)
Changes in Assets and Liabilities:			
Accounts receivable	(186.2)	(52.3)	(188.0)
Inventories	41.4	19.0	38.9
Accounts payable	268.4	49.0	108.8
Customer deposits and credits	(25.4)	(2.5)	(52.3)
Taxes accrued	20.2	10.2	12.1
Interest accrued	(21.7)	(33.9)	(8.7)
Exchange gas receivable/payable	(21.5)	(64.5)	36.9
Other accruals	43.5	31.8	(6.0)
Prepayments and other current assets	(14.5)	(13.3)	(0.4)
Regulatory assets/liabilities	(53.2)	57.5	(187.9)
Postretirement and postemployment benefits	58.2	(380.9)	(44.8)
Deferred charges and other noncurrent assets	3.8	(2.0)	(1.2)
Other noncurrent liabilities	(2.8)	(34.4)	(0.3)
Net Cash Flows from Operating Activities	540.1	742.2	803.3
Investing Activities			
Capital expenditures	(1,818.2)	(1,695.8)	(1,475.2)
Cost of removal	(104.3)	(109.0)	(110.1)
Purchases of available-for-sale securities	(90.0)	(168.4)	(38.3)
Sales of available-for-sale securities	82.3	163.1	33.0
Other investing activities	4.1	1.6	(12.4)
Net Cash Flows used for Investing Activities	(1,926.1)	(1,808.5)	(1,603.0)
Financing Activities			
Issuance of long-term debt	350.0	3,250.0	500.0
Repayments of long-term debt and capital lease obligations	(1,046.1)	(1,855.0)	(434.6)
Premiums and other debt related costs	(46.0)	(144.3)	(3.7)
Issuance of short-term debt (maturity > 90 days)	950.0	—	—
Change in short-term borrowings, net (maturity ≤ 90 days)	(178.5)	(282.4)	920.6
Issuance of common stock, net of issuance costs	848.2	336.7	23.1
Issuance of preferred stock, net of issuance costs	880.0	—	—
Acquisition of treasury stock	(4.0)	(7.2)	(9.4)
Dividends paid - common stock	(273.3)	(229.1)	(205.5)
Dividends paid - preferred stock	(11.6)	—	—
Net Cash Flows from Financing Activities	1,468.7	1,068.7	790.5
Change in cash, cash equivalents and restricted cash	82.7	2.4	(9.2)
Cash, cash equivalents and restricted cash at beginning of period	38.4	36.0	45.2
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 121.1	$ 38.4	$ 36.0

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NISOURCE INC.
STATEMENTS OF CONSOLIDATED STOCKHOLDERS' EQUITY

(in millions)	Common Stock	Treasury Stock	Additional Paid-In Capital	Retained Deficit	Accumulated Other Comprehensive Loss	Total
Balance as of January 1, 2016	**$ 3.2**	**$ (79.3)**	**$ 5,078.0**	**$ (1,123.3)**	**$ (35.1)**	**$ 3,843.5**
Comprehensive Income:						
Net Income	—	—	—	331.5	—	331.5
Other comprehensive income, net of tax	—	—	—	—	10.0	10.0
Common stock dividends ($0.64 per share)	—	—	—	(205.7)	—	(205.7)
Treasury stock acquired	—	(9.4)	—	—	—	(9.4)
Cumulative effect of change in accounting principle[(1)]	—	—	—	25.3	—	25.3
Stock issuances:						
Common stock	0.1	—	—	—	—	0.1
Employee stock purchase plan	—	—	4.7	—	—	4.7
Long-term incentive plan	—	—	20.9	—	—	20.9
401(k) and profit sharing	—	—	41.4	—	—	41.4
Dividend reinvestment plan	—	—	8.9	—	—	8.9
Balance as of December 31, 2016	**$ 3.3**	**$ (88.7)**	**$ 5,153.9**	**$ (972.2)**	**$ (25.1)**	**$ 4,071.2**
Comprehensive Loss:						
Net Income	—	—	—	128.5	—	128.5
Other comprehensive loss, net of tax	—	—	—	—	(18.3)	(18.3)
Common stock dividends ($0.70 per share)	—	—	—	(229.4)	—	(229.4)
Treasury stock acquired	—	(7.2)	—	—	—	(7.2)
Stock issuances:						
Employee stock purchase plan	—	—	5.0	—	—	5.0
Long-term incentive plan	—	—	14.9	—	—	14.9
401(k) and profit sharing	—	—	34.3	—	—	34.3
Dividend reinvestment plan	—	—	6.4	—	—	6.4
ATM Program	0.1	—	314.6	—	—	314.7
Balance as of December 31, 2017	**$ 3.4**	**$ (95.9)**	**$ 5,529.1**	**$ (1,073.1)**	**$ (43.4)**	**$ 4,320.1**

[(1)]See Note 2, "Recent Accounting Pronouncements," for additional information.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NISOURCE INC.
STATEMENTS OF CONSOLIDATED STOCKHOLDERS' EQUITY

(in millions)	Common Stock	Preferred Stock	Treasury Stock	Additional Paid-In Capital	Retained Deficit	Accumulated Other Comprehensive Loss	Total
Balance as of December 31, 2017	**$ 3.4**	**$ —**	**$ (95.9)**	**$ 5,529.1**	**$ (1,073.1)**	**$ (43.4)**	**$ 4,320.1**
Comprehensive Income:							
Net Loss	—	—	—	—	(50.6)	—	(50.6)
Other comprehensive income, net of tax	—	—	—	—	—	15.7	15.7
Dividends:							
Common stock ($0.78 per share)	—	—	—	—	(273.5)	—	(273.5)
Preferred stock ($28.88 per share)	—	—	—	—	(11.6)	—	(11.6)
Treasury stock acquired	—	—	(4.0)	—	—	—	(4.0)
Cumulative effect of change in accounting principle[(1)]	—	—	—	—	9.5	(9.5)	—
Stock issuances:							
Common stock - private placement	0.3	—	—	599.3	—	—	599.6
Preferred stock	—	880.0	—	—	—	—	880.0
Employee stock purchase plan	—	—	—	5.5	—	—	5.5
Long-term incentive plan	—	—	—	15.4	—	—	15.4
401(k) and profit sharing	—	—	—	21.8	—	—	21.8
ATM program	0.1	—	—	232.4	—	—	232.5
Balance as of December 31, 2018	**$ 3.8**	**$ 880.0**	**$ (99.9)**	**$ 6,403.5**	**$ (1,399.3)**	**$ (37.2)**	**$ 5,750.9**

[(1)]See Note 2, "Recent Accounting Pronouncements," for additional information.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

NISOURCE INC.
STATEMENTS OF CONSOLIDATED STOCKHOLDERS' EQUITY

	Preferred	Common		
(in thousands)	Shares	Shares	Treasury	Outstanding
Balance as of January 1, 2016	**—**	**322,181**	**(3,071)**	**319,110**
Treasury stock acquired			(433)	(433)
Issued:				
Employee stock purchase plan	—	201	—	201
Long-term incentive plan	—	2,103	—	2,103
401(k) and profit sharing plan	—	1,793	—	1,793
Dividend reinvestment plan	—	386	—	386
Balance as of December 31, 2016	**—**	**326,664**	**(3,504)**	**323,160**
Treasury stock acquired			(293)	(293)
Issued:				
Employee stock purchase plan	—	207	—	207
Long-term incentive plan	—	351	—	351
401(k) and profit sharing plan	—	1,396	—	1,396
Dividend reinvestment plan	—	264	—	264
ATM Program	—	11,931	—	11,931
Balance as of December 31, 2017	**—**	**340,813**	**(3,797)**	**337,016**
Treasury stock acquired			(166)	(166)
Issued:				
Common stock - private placement[1]	—	24,964	—	24,964
Preferred stock[1]	420			
Employee stock purchase plan	—	223	—	223
Long-term incentive plan	—	561	—	561
401(k) and profit sharing plan	—	882	—	882
ATM program	—	8,883	—	8,883
Balance as of December 31, 2018	**420**	**376,326**	**(3,963)**	**372,363**

[1]See Note 12, "Equity," for additional information.

Accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

1. Nature of Operations and Summary of Significant Accounting Policies

A. Company Structure and Principles of Consolidation. We are an energy holding company incorporated in Delaware and headquartered in Merrillville, Indiana. Our subsidiaries are fully regulated natural gas and electric utility companies serving approximately 4.0 million customers in seven states. We generate substantially all of our operating income through these rate-regulated businesses. The consolidated financial statements include the accounts of us and our majority-owned subsidiaries after the elimination of all intercompany accounts and transactions.

B. Use of Estimates. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

C. Cash, Cash Equivalents and Restricted Cash. We consider all highly liquid investments with original maturities of three months or less to be cash equivalents. We report amounts deposited in brokerage accounts for margin requirements as restricted cash. In addition, we have amounts deposited in trust to satisfy requirements for the provision of various property, liability, workers compensation, and long-term disability insurance, which is classified as restricted cash on the Consolidated Balance Sheets and disclosed with cash and cash equivalents on the Statements of Consolidated Cash Flows.

D. Accounts Receivable and Unbilled Revenue. Accounts receivable on the Consolidated Balance Sheets includes both billed and unbilled amounts. Unbilled amounts of accounts receivable relate to a portion of a customer’s consumption of gas or electricity from the date of the last cycle billing date through the last day of the month (balance sheet date). Factors taken into consideration when estimating unbilled revenue include historical usage, customer rates and weather. Accounts receivable fluctuates from year to year depending in large part on weather impacts and price volatility. Our accounts receivable on the Consolidated Balance Sheets include unbilled revenue, less reserves, in the amounts of $324.2 million and $359.4 million as of December 31, 2018 and 2017, respectively. The reserve for uncollectible receivables is our best estimate of the amount of probable credit losses in the existing accounts receivable. We determined the reserve based on historical experience and in consideration of current market conditions. Account balances are charged against the allowance when it is anticipated the receivable will not be recovered. Refer to Note 3, "Revenue Recognition," for additional information on customer-related accounts receivable.

E. Investments in Debt Securities. Our investments in debt securities are carried at fair value and are designated as available-for-sale. These investments are included within “Other investments” on the Consolidated Balance Sheets. Unrealized gains and losses, net of deferred income taxes, are recorded to accumulated other comprehensive income or loss. These investments are monitored for other than temporary declines in market value. Realized gains and losses and permanent impairments are reflected in the Statements of Consolidated Income (Loss). No material impairment charges were recorded for the years ended December 31, 2018, 2017 or 2016. Refer to Note 16, "Fair Value," for additional information.

F. Basis of Accounting for Rate-Regulated Subsidiaries. Rate-regulated subsidiaries account for and report assets and liabilities consistent with the economic effect of the way in which regulators establish rates, if the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates can be charged and collected. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income are deferred on the Consolidated Balance Sheets and are later recognized in income as the related amounts are included in customer rates and recovered from or refunded to customers.

In the event that regulation significantly changes the opportunity for us to recover our costs in the future, all or a portion of our regulated operations may no longer meet the criteria for regulatory accounting. In such an event, a write-down of all or a portion of our existing regulatory assets and liabilities could result. If transition cost recovery was approved by the appropriate regulatory bodies that would meet the requirements under GAAP for continued accounting as regulatory assets and liabilities during such recovery period, the regulatory assets and liabilities would be reported at the recoverable amounts. If unable to continue to apply the provisions of regulatory accounting, we would be required to apply the provisions of ASC 980-20, *Discontinuation of Rate-Regulated Accounting*. In management’s opinion, our regulated subsidiaries will be subject to regulatory accounting for the foreseeable future. Refer to Note 8, "Regulatory Matters," for additional information.

G. Plant and Other Property and Related Depreciation and Maintenance. Property, plant and equipment (principally utility plant) is stated at cost. The rate-regulated subsidiaries record depreciation using composite rates on a straight-line basis over the remaining service lives of the electric, gas and common properties as approved by the appropriate regulators.

Non-utility property is generally depreciated on a straight-line basis over the life of the associated asset. Refer to Note 5, "Property, Plant and Equipment," for additional information related to depreciation expense.

For rate-regulated companies, AFUDC is capitalized on all classes of property except organization costs, land, autos, office equipment, tools and other general property purchases. The allowance is applied to construction costs for that period of time between the date of the expenditure and the date on which such project is placed in service. Our pre-tax rate for AFUDC was 3.5% in 2018, 4.0% in 2017 and 4.5% in 2016.

Generally, our subsidiaries follow the practice of charging maintenance and repairs, including the cost of removal of minor items of property, to expense as incurred. When our subsidiaries retire regulated property, plant and equipment, original cost plus the cost of retirement, less salvage value, is charged to accumulated depreciation. However, when it becomes probable a regulated asset will be retired substantially in advance of its original expected useful life or is abandoned, the cost of the asset and the corresponding accumulated depreciation is recognized as a separate asset. If the asset is still in operation, the net amount is classified as "Other property, at cost, less accumulated depreciation" on the Consolidated Balance Sheets. If the asset is no longer operating, the net amount is classified in "Regulatory assets" on the Consolidated Balance Sheets. If we are able to recover a full return of and on investment, the carrying value of the asset is based on historical cost. If we are not able to recover a full return on investment, a loss on impairment is recognized to the extent the net book value of the asset exceeds the present value of future revenues discounted at the incremental borrowing rate.

When our subsidiaries sell entire regulated operating units, or retire or sell nonregulated properties, the original cost and accumulated depreciation and amortization balances are removed from "Property, Plant and Equipment" on the Consolidated Balance Sheets. Any gain or loss is recorded in earnings, unless otherwise required by the applicable regulatory body. Refer to Note 5, "Property, Plant and Equipment," for further information.

External and internal costs associated with computer software developed for internal use are capitalized. Capitalization of such costs commences upon the completion of the preliminary stage of each project. Once the installed software is ready for its intended use, such capitalized costs are amortized on a straight-line basis generally over a period of five years, except for certain significant enterprise-wide technology investments which are amortized over a ten-year period.

External and internal up-front implementation costs associated with cloud computing arrangements that are service contracts are deferred on the Consolidated Balance Sheets. Once the installed software is ready for its intended use, such deferred costs are amortized on a straight-line basis to "Operation and maintenance," over the minimum term of the contract plus contractually-provided renewal periods that are reasonable expected to be exercised -- generally up to a maximum of five years.

H. Goodwill and Other Intangible Assets. Substantially all of our goodwill relates to the excess of cost over the fair value of the net assets acquired in the Columbia acquisition on November 1, 2000. We test our goodwill for impairment annually as of May 1, or more frequently if events and circumstances indicate that goodwill might be impaired. Fair value of our reporting units is determined using a combination of income and market approaches.

We have other intangible assets consisting primarily of franchise rights apart from goodwill that were identified as part of the purchase price allocations associated with the acquisition of Columbia of Massachusetts which is being amortized on a straight-line basis over forty years from the date of acquisition. See Note 6, "Goodwill and Other Intangible Assets," for additional information.

I. Accounts Receivable Transfer Program. Certain of our subsidiaries have agreements with third parties to transfer certain accounts receivable without recourse. These transfers of accounts receivable are accounted for as secured borrowings. The entire gross receivables balance remains on the December 31, 2018 and 2017 Consolidated Balance Sheets and short-term debt is recorded in the amount of proceeds received from the transferees involved in the transactions. Refer to Note 17, "Transfers of Financial Assets," for further information.

J. Gas Cost and Fuel Adjustment Clause. Our regulated subsidiaries defer most differences between gas and fuel purchase costs and the recovery of such costs in revenues, and adjust future billings for such deferrals on a basis consistent with applicable state-approved tariff provisions. These deferred balances are recorded as "Regulatory assets" or "Regulatory liabilities," as appropriate, on the Consolidated Balance Sheets. Refer to Note 8, "Regulatory Matters," for additional information.

K. Inventory. Both the LIFO inventory methodology and the weighted average cost methodology are used to value natural gas in storage, as approved by regulators for all of our regulated subsidiaries. Inventory valued using LIFO was $47.5 million and $45.5 million at December 31, 2018 and 2017, respectively. Based on the average cost of gas using the LIFO method, the estimated replacement cost of gas in storage was less than the stated LIFO cost by $12.2 million and $17.4 million at December 31, 2018 and 2017, respectively. Gas inventory valued using the weighted average cost methodology was $239.3 million at December 31, 2018 and $239.6 million at December 31, 2017.

Electric production fuel is valued using the weighted average cost inventory methodology, as approved by NIPSCO's regulator.

Materials and supplies are valued using the weighted average cost inventory methodology.

L. Accounting for Exchange and Balancing Arrangements of Natural Gas. Our Gas Distribution Operations segment enters into balancing and exchange arrangements of natural gas as part of its operations and off-system sales programs. We record a receivable or payable for any of our respective cumulative gas imbalances, as well as for any gas inventory borrowed or lent under a Gas Distribution Operations exchange agreement. Exchange gas is valued based on individual regulatory jurisdiction requirements (for example, historical spot rate, spot at the beginning of the month). These receivables and payables are recorded as “Exchange gas receivable” or “Exchange gas payable” on our Consolidated Balance Sheets, as appropriate.

M. Accounting for Risk Management Activities. We account for our derivatives and hedging activities in accordance with ASC 815. We recognize all derivatives as either assets or liabilities on the Consolidated Balance Sheets at fair value, unless such contracts are exempted as a normal purchase normal sale under the provisions of the standard. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and resulting designation.

We have elected not to net fair value amounts for any of our derivative instruments or the fair value amounts recognized for the right to receive cash collateral or obligation to pay cash collateral arising from those derivative instruments recognized at fair value, which are executed with the same counterparty under a master netting arrangement. See Note 9, "Risk Management Activities," for additional information.

N. Income Taxes and Investment Tax Credits. We record income taxes to recognize full interperiod tax allocations. Under the asset and liability method, deferred income taxes are provided for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amount and the tax basis of existing assets and liabilities. Previously recorded investment tax credits of the regulated subsidiaries were deferred on the balance sheet and are being amortized to book income over the regulatory life of the related properties to conform to regulatory policy.

To the extent certain deferred income taxes of the regulated companies are recoverable or payable through future rates, regulatory assets and liabilities have been established. Regulatory assets for income taxes are primarily attributable to property-related tax timing differences for which deferred taxes had not been provided in the past, when regulators did not recognize such taxes as costs in the rate-making process. Regulatory liabilities for income taxes are primarily attributable to the regulated companies’ obligation to refund to ratepayers deferred income taxes provided at rates higher than the current Federal income tax rate. Such property-related amounts are credited to ratepayers using either the average rate assumption method or the reverse South Georgia method. Non property-related amounts are credited to ratepayers consistent with state utility commission direction.

Pursuant to the Internal Revenue Code and relevant state taxing authorities, we and our subsidiaries file consolidated income tax returns for federal and certain state jurisdictions. We and our subsidiaries are parties to an agreement (the “Intercompany Income Tax Allocation Agreement”) that provides for the allocation of consolidated tax liabilities. The Intercompany Income Tax Allocation Agreement generally provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax.

O. Environmental Expenditures. We accrue for costs associated with environmental remediation obligations when the incurrence of such costs is probable and the amounts can be reasonably estimated, regardless of when the expenditures are actually made. The undiscounted estimated future expenditures are based on currently enacted laws and regulations, existing technology and estimated site-specific costs where assumptions may be made about the nature and extent of site contamination, the extent of cleanup efforts, costs of alternative cleanup methods and other variables. The liability is adjusted as further information is discovered or circumstances change. The accruals for estimated environmental expenditures are recorded on the Consolidated Balance Sheets in “Legal and environmental” for short-term portions of these liabilities and “Other noncurrent liabilities” for the respective long-term portions of these liabilities. Rate-regulated subsidiaries applying regulatory accounting establish regulatory assets on the Consolidated Balance Sheets to the extent that future recovery of environmental remediation costs is probable through the regulatory process. Refer to Note 18, "Other Commitments and Contingencies," for further information.

P. Excise Taxes. We account for excise taxes that are customer liabilities by separately stating on our invoices the tax to our customers and recording amounts invoiced as liabilities payable to the applicable taxing jurisdiction. Such balances are presented within "Other accruals" on the Consolidated Balance Sheets. These types of taxes collected from customers, comprised largely of sales taxes, are presented on a net basis affecting neither revenues nor cost of sales. We account for excise taxes for which we are liable by recording a liability for the expected tax with a corresponding charge to “Other taxes” expense on the Statements of Consolidated Income (Loss).

Q. Accrued Insurance Liabilities. We accrue for insurance costs related to workers compensation, automobile, property, general and employment practices liabilities based on the most probable value of each claim. In general, claim values are determined by professional, licensed loss adjusters who consider the facts of the claim, anticipated indemnification and legal expenses, and respective state rules. Claims are reviewed by us at least quarterly and an adjustment is made to the accrual based on the most current information. Refer to Note 18-E "Other Matters" for further information on accrued insurance liabilities related to the Greater Lawrence Incident.

2. Recent Accounting Pronouncements

Recently Issued Accounting Pronouncements

We are currently evaluating the impact of certain ASUs on our Consolidated Financial Statements or Notes to Consolidated Financial Statements, which are described below:

Standard	Description	Effective Date	Effect on the financial statements or other significant matters
ASU 2018-14, *Compensation—Retirement Benefits—Defined Benefit Plans—General (Subtopic 715-20): Disclosure Framework—Changes to the Disclosure Requirements for Defined Benefit Plans*	The pronouncement modifies the disclosure requirements for defined benefit pension and other postretirement benefit plans. The guidance removes disclosures that are no longer considered cost beneficial, clarifies the specific requirements of disclosures and adds disclosure requirements identified as relevant. The modifications affect annual period disclosures and must be applied on a retrospective basis to all periods presented.	Annual periods ending after December 15, 2020. Early adoption is permitted.	We are currently evaluating the effects of this pronouncement on our Notes to Consolidated Financial Statements. We tentatively expect to adopt this ASU on its effective date.
ASU 2016-13, *Financial Instruments-Credit Losses (Topic 326)*	The pronouncement changes the impairment model for most financial assets, replacing the current "incurred loss" model. ASU 2016-13 will require the use of an "expected loss" model for instruments measured at amortized cost. It will also require entities to record allowances for available-for-sale debt securities rather than impair the carrying amount of the securities. Subsequent improvements to the estimated credit losses of available-for-sale securities will be recognized immediately in earnings instead of over time as they are under historic guidance.	Annual periods beginning after December 15, 2019, including interim periods therein. Early adoption is permitted for annual or interim periods beginning after December 15, 2018.	We maintain investments in U.S. Treasury, corporate and mortgage-backed debt securities, which are pledged as collateral for trust accounts related to our wholly-owned insurance company. These debt securities are classified as available for sale. We also have recorded balances for trade receivables that fall within the scope of the standard. We are currently evaluating the impact of adoption, if any, on our Consolidated Financial Statements and Notes to Consolidated Financial Statements.

Recently Adopted Accounting Pronouncements

Standard	Adoption
ASU 2018-15, *Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract*	In August 2018, the FASB issued this ASU, which amends current guidance to align the accounting for costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing costs associated with developing or obtaining internal-use software. We elected to early adopt the ASU on a prospective basis, effective October 1, 2018. As a result of adopting this ASU, we will defer onto the Consolidated Balance Sheets up-front implementation costs of cloud computing arrangements if they would have been capitalized in a similar on-premise software solution.
ASU 2018-02, *Income Statement—Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income*	We adopted this ASU effective March 31, 2018. Upon adoption, $9.5 million of tax effects that were stranded in accumulated other comprehensive income (loss) as a result of the implementation of the TCJA were reclassified to retained deficit. This change is reflected on our Statements of Consolidated Stockholders' Equity.
ASU 2016-15, *Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments (a consensus of the Emerging Issues Task Force)*	We adopted this ASU effective January 1, 2018. The adoption of this standard did not have a material impact on our Consolidated Financial Statements or Notes to Consolidated Financial Statements.
ASU 2018-11, Leases (Topic 842): Targeted Improvements ASU 2018-01, Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842 ASU 2016-02, Leases (Topic 842)	We adopted the provisions of ASC 842 beginning on January 1, 2019, using the transition method provided in ASU 2018-11, which was applied to all existing leases at that date. As such, results for reporting periods beginning after January 1, 2019 will be presented under ASC 842, while prior period amounts will continue to be reported in accordance with ASC 840. To ease the process of implementing ASC 842, we elected a number of practical expedients, including the "practical expedient package" described in ASC 842-10-65-1 and the provisions of ASU 2018-01, which allows us to not evaluate existing land easements under ASC 842. We elected the short-term lease recognition exemption for all leases that qualify. As such, for those leases with terms less than 12 months, we will not recognize ROU assets or lease liabilities. Further, ASC 842 provides lessees the option of electing an accounting policy, by class of underlying asset, in which the lessee may choose not to separate nonlease components from lease components. We elected this practical expedient for our leases of fleet vehicles and railcars. We also elected to use a practical expedient that allows the use of hindsight in determining lease terms when evaluating leases that existed at the implementation date. We are the lessee for substantially all of our current leasing activity. Upon adopting ASC 842 we began recognizing right-of-use assets and liabilities associated with operating leases (other than short term operating leases) on our Consolidated Balance Sheets resulting in an increase in assets and liabilities of approximately $60 million. The adoption of ASC 842 did not have a material impact to our results of operations or cash flows. We have implemented key system functionality and internal controls to facilitate the preparation of financial information upon adoption. Our SEC filings will include expanded disclosures to comply with the provisions of ASC 842 beginning with our quarterly report on Form 10-Q for the first quarter of 2019.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

Standard	Adoption
ASU 2016-12, *Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients*	See Note 3, "Revenue Recognition," for our discussion of the effects of implementing these standards.
ASU 2016-08, *Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations*	
ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*	

We also adopted ASU 2017-07, *Compensation - Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost,* effective January 1, 2018. We continue to present the service cost component of net periodic benefit cost within "Operation and maintenance;" however, other components of the net periodic benefit cost (including regulatory deferrals and settlement charges) are now presented separately within "Other, net" on our Statements of Consolidated Income (Loss).

Changes in income statement presentation were implemented on a retrospective basis. The impact of this ASU on previously issued annual financial statements is summarized in the tables below:

Year Ended December 31, 2016 *(in millions)*	**As Previously Reported**	**Effect of Change[(1)]**	**As Adjusted**
Operation and maintenance	$ 1,453.7	$ (7.9)	$ 1,445.8
Total Operating Expenses	3,634.3	(7.9)	3,626.4
Operating Income	858.2	7.9	866.1
Other Income (Deductions)			
Other, net	1.5	(7.9)	(6.4)
Total Other Deductions	$ (348.0)	$ (7.9)	$ (355.9)

[(1)] The effect of this change is attributable to our business segments: Gas Distribution Operations, Electric Operations, and Corporate and Other in the amounts of $4.3 million, $(9.8) million, and $(2.4) million, respectively.

Year Ended December 31, 2017 *(in millions)*	**As Previously Reported**	**Effect of Change[(1)]**	**As Adjusted**
Operation and maintenance	$ 1,612.3	$ (10.6)	$ 1,601.7
Total Operating Expenses	3,964.0	(10.6)	3,953.4
Operating Income	910.6	10.6	921.2
Other Income (Deductions)			
Other, net	(2.8)	(10.6)	(13.4)
Total Other Deductions	$ (467.5)	$ (10.6)	$ (478.1)

[(1)] The effect of this change is attributable to our business segments: Gas Distribution Operations, Electric Operations, and Corporate and Other in the amounts of $(4.4) million, $(2.6) million, and $(3.6) million, respectively.

3. Revenue Recognition

ASC 606 Adoption. In 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (ASC 606). ASU 2014-09 outlines a single, comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance. The core principle of the new standard is that an entity should recognize revenue to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In 2016, the FASB issued ASU 2016-08, Revenue from Contracts with Customers (ASC 606): Principal versus Agent Considerations, and ASU 2016-12, Revenue from Contracts with Customers (ASC 606): Narrow-Scope Improvements and Practical Expedients. We adopted the provisions of ASC 606 beginning on January 1, 2018 using a modified retrospective method, which was applied to all contracts. No material adjustments were made to January 1, 2018 opening balances as a result of the adoption. As required under the modified retrospective method of adoption, results for reporting periods beginning after January 1, 2018 are presented under ASC 606, while prior period amounts are not adjusted and continue to be reported in accordance with ASC 605.

The table below provides results for the year ended December 31, 2018 as if it had been prepared under historic accounting guidance. We included operating revenue information for the years ended December 31, 2017 and 2016 for comparability.

Year Ended December 31, *(in millions)*	2018	2017	2016
Operating Revenues			
Gas Distribution	**$ 2,348.4**	$ 2,063.2	$ 1,850.9
Gas Transportation	**1,055.2**	1,021.5	964.6
Electric	**1,707.4**	1,785.5	1,660.8
Other	**3.5**	4.4	16.2
Total Operating Revenues	**$ 5,114.5**	$ 4,874.6	$ 4,492.5

Beginning in 2018 with the adoption of ASC 606, the Statements of Consolidated Income (Loss) disaggregates "Customer revenues" (i.e. ASC 606 Revenues) from "Other revenues," both of which are discussed in more detail below.

Customer Revenues. Substantially all of our revenues are tariff-based, which we have concluded is within the scope of ASC 606. Under ASC 606, the recipients of our utility service meet the definition of a customer, while the operating company tariffs represent an agreement that meets the definition of a contract. ASC 606 defines a contract as an agreement between two or more parties, in this case us and the customer, which creates enforceable rights and obligations. In order to be considered a contract, we have determined that it is probable that substantially all of the consideration to which we are entitled from customers will be collected upon satisfaction of performance obligations. We maintain common utility credit risk mitigation practices, including requiring deposits and actively pursuing collection of past due amounts. In addition, our regulated operations utilize certain regulatory mechanisms that facilitate recovery of bad debt costs within tariff-based rates, which provides further evidence of collectibility.

Customers in certain of our jurisdictions participate in programs that allow for a fixed payment each month regardless of usage. Payments received that exceed the value of gas or electricity actually delivered are recorded as a liability and presented in "Customer Deposits and Credits." Amounts in this account are reduced and revenue is recorded when customer usage begins to exceed payments received.

We have identified our performance obligations created under tariff-based sales as 1) the commodity (natural gas or electricity, which includes generation and capacity) and 2) delivery. These commodities are sold and / or delivered to and generally consumed by customers simultaneously, leading to satisfaction of our performance obligations over time as gas or electricity is delivered to customers. Due to the at-will nature of utility customers, performance obligations are limited to the services requested and received to date. Once complete, we generally maintain no additional performance obligations.

Transaction prices for each performance obligation are generally prescribed by each operating company's respective tariff. Rates include provisions to adjust billings for fluctuations in fuel and purchased power costs and cost of natural gas. Revenues are adjusted for differences between actual costs subject to reconciliation and the amounts billed in current rates. Under or over recovered revenues related to these cost recovery mechanisms are included in regulatory assets or liabilities on the Consolidated Balance Sheets and are recovered from or returned to customers through adjustments to tariff rates. As we provide and deliver service to customers, revenue is recognized based on the transaction price allocated to each performance obligation. In general, revenue recognized from tariff-based sales is equivalent to the value of natural gas or electricity supplied and billed each period, in addition to an estimate for deliveries completed during the period but not yet billed to the customer.

In addition to tariff-based sales, our Gas Distribution Operations segment enters into balancing and exchange arrangements of natural gas as part of our operations and off-system sales programs. We have concluded that these sales are within the scope of ASC 606. Performance obligations for these types of sales include transportation and storage of natural gas and can be satisfied at a point in time or over a period of time, depending on the specific transaction. For those transactions that span a period of time, we record a receivable or payable for any cumulative gas imbalances, as well as for any gas inventory borrowed or lent under a Gas Distributions Operations exchange agreement.

Revenue Disaggregation and Reconciliation. We disaggregate revenue from contracts with customers based upon reportable segment as well as by customer class. As our revenues are primarily earned over a period of time, and we do not earn a material amount of revenues at a point in time, revenues are not disaggregated as such below. The Gas Distribution Operations segment provides natural gas service and transportation for residential, commercial and industrial customers in Ohio, Pennsylvania, Virginia, Kentucky, Maryland, Indiana and Massachusetts. The Electric Operations segment provides electric service in 20 counties in the northern part of Indiana.

The table below reconciles revenue disaggregation by customer class to segment revenue as well as to revenues reflected on the Statements of Consolidated Income (Loss):

Year Ended December 31, 2018 *(in millions)*	Gas Distribution Operations	Electric Operations	Corporate and Other	Total
Customer Revenues[1]				
Residential	$ 2,250.0	$ 494.7	$ —	$ 2,744.7
Commercial	751.9	492.7	—	1,244.6
Industrial	228.0	613.6	—	841.6
Off-system	92.4	—	—	92.4
Miscellaneous	49.7	17.4	0.7	67.8
Total Customer Revenues	$ 3,372.0	$ 1,618.4	$ 0.7	$ 4,991.1
Other Revenues	34.4	89.0	—	123.4
Total Operating Revenues	$ 3,406.4	$ 1,707.4	$ 0.7	$ 5,114.5

[1] Customer revenue amounts exclude intersegment revenues. See Note 22, "Segments of Business," for discussion of intersegment revenues.

Customer Accounts Receivable. Accounts receivable on our Consolidated Balance Sheets includes both billed and unbilled amounts, as well as certain amounts that are not related to customer revenues. Unbilled amounts of accounts receivable relate to a portion of a customer's consumption of gas or electricity from the date of the last cycle billing through the last day of the month (balance sheet date). Factors taken into consideration when estimating unbilled revenue include historical usage, customer rates and weather. The opening and closing balances of customer receivables for the years ended December 31, 2018 and 2017 are presented in the table below. We had no significant contract assets or liabilities during the period. Additionally, we have not incurred any significant costs to obtain or fulfill contracts.

(in millions)	Customer Accounts Receivable, Billed (less reserve)[1]	Customer Accounts Receivable, Unbilled (less reserve)[2]
Balance as of December 31, 2017	$ 477.0	$ 378.6
Balance as of December 31, 2018	540.5	349.1
Increase (Decrease)	$ 63.5	$ (29.5)

[1] Customer billed receivables increased over the period due to November 2018 being colder than November 2017, leading to more gas usage included in December bills.
[2] Customer unbilled receivables decreased over the period due December 2018 being warmer than December 2017, leading to less estimated gas usage.

Utility revenues are billed to customers monthly on a cycle basis. We generally expect that substantially all customer accounts receivable will be collected within the month following customer billing, as this revenue consists primarily of monthly, tariff-based billings for service and usage.

Other Revenues. As permitted by accounting principles generally accepted in the United States, regulated utilities have the ability to earn certain types of revenue that are outside the scope of ASC 606. These revenues primarily represent revenue earned under alternative revenue programs. Alternative revenue programs represent regulator-approved programs that allow for the adjustment of billings and revenue for certain broad, external factors, or for additional billings if the entity achieves certain objectives, such as a specified reduction of costs. We maintain a variety of these programs, including demand side management initiatives that recover costs associated with the implementation of energy efficiency programs, as well as normalization programs that adjust revenues for the effects of weather or other external factors. Additionally, we maintain certain programs with future test periods that operate similarly to FERC formula rate programs and allow for recovery of costs incurred to replace aging infrastructure. When the criteria to recognize Alternative Revenue have been met, we establish a regulatory asset and present revenue from alternative revenue programs on the Statements of Consolidated Income (Loss) as “Other revenues.” When amounts previously recognized under Alternative Revenue accounting guidance are billed, we reduce the regulatory asset and record a customer account receivable.

4. Earnings Per Share

Basic EPS is computed by dividing net income attributable to common shareholders by the weighted-average number of shares of common stock outstanding for the period. The weighted-average shares outstanding for diluted EPS includes the incremental effects of the various long-term incentive compensation plans when the impact of such plans would be dilutive. The calculation of diluted earnings per share excludes the impact of forward agreements (see Note 12, "Equity"), which had an anti-dilutive effect for the periods outstanding. The computation of diluted average common shares for the year ended December 31, 2018 is not presented as we are presenting a net loss on the Statements of Consolidated Income (Loss) for the period, and any incremental shares would have an anti-dilutive impact on EPS. The computation of diluted average common shares is as follows:

Year Ended December 31, *(in thousands)*	2017	2016
Denominator		
Basic average common shares outstanding	329,388	321,805
Dilutive potential common shares:		
Shares contingently issuable under employee stock plans	547	165
Shares restricted under stock plans	821	1,554
Diluted Average Common Shares	330,756	323,524

5. Property, Plant and Equipment

Our property, plant and equipment on the Consolidated Balance Sheets are classified as follows:

At December 31, *(in millions)*		**2018**		2017
Property, Plant and Equipment				
Gas Distribution Utility[(1)]	**$**	**13,776.0**	$	12,531.0
Electric Utility[(1)]		**8,374.2**		7,403.8
Corporate		**155.8**		141.3
Construction Work in Process		**474.8**		950.5
Non-Utility and Other[(2)]		**38.7**		623.3
Total Property, Plant and Equipment	**$**	**22,819.5**	$	21,649.9
Accumulated Depreciation and Amortization				
Gas Distribution Utility[(1)]	**$**	**(3,373.8)**	$	(3,227.8)
Electric Utility[(1)]		**(3,809.5)**		(3,673.2)
Corporate		**(74.6)**		(52.6)
Non-Utility and Other[(2)]		**(19.1)**		(336.8)
Total Accumulated Depreciation and Amortization	**$**	**(7,277.0)**	$	(7,290.4)
Net Property, Plant and Equipment	**$**	**15,542.5**	$	14,359.5

[(1)]NIPSCO's common utility plant and associated accumulated depreciation and amortization are allocated between Gas Distribution Utility and Electric Utility Property, Plant and Equipment.
[(2)]Non-Utility and Other as of December 31, 2017 includes net book value of $247.8 million related to Bailly Generating Station (Units 7 and 8) which was reclassified from Electric Utility in the fourth quarter of 2016. In May 2018, Units 7 and 8 were retired from service and the remaining balance was reclassified to "Regulatory assets (noncurrent)" on the Consolidated Balance Sheets. See Note 18-E, "Other Matters," and Note 8, "Regulatory Matters," for additional information.

The weighted average depreciation provisions for utility plant, as a percentage of the original cost, for the periods ended December 31, 2018, 2017 and 2016 were as follows:

	2018	2017	2016
Electric Operations[(1)]	**2.9%**	3.4%	3.3%
Gas Distribution Operations	**2.2%**	2.1%	2.1%

[(1)]Lower depreciation rate in 2018 due to reduced EERM-related depreciation expense and higher depreciable base from transmission assets being placed into service in 2018.

We recognized depreciation expense of $503.4 million, $501.5 million and $475.1 million for the years ended 2018, 2017 and 2016, respectively.

Amortization of Software Costs. We amortized $54.1 million in 2018, $44.0 million in 2017 and $41.4 million in 2016 related to software costs. Our unamortized software balance was $159.5 million and $189.0 million at December 31, 2018 and 2017, respectively.

6. Goodwill and Other Intangible Assets

Goodwill. Substantially all of our goodwill relates to the excess of cost over the fair value of the net assets acquired in the Columbia acquisition on November 1, 2000. The following presents our goodwill balance allocated by segment as of December 31, 2018:

(in millions)		Gas Distribution Operations		Electric Operations		Corporate and Other		**Total**
Goodwill	$	1,690.7	$	—	$	—	**$**	**1,690.7**

We applied the qualitative "step 0" analysis to our reporting units for the annual impairment test performed as of May 1, 2018. For this test, we assessed various assumptions, events and circumstances that would have affected the estimated fair value of the reporting units as compared to their base line May 1, 2016 "step 1" fair value measurement. The results of this assessment indicated that it was not more likely than not that our reporting unit fair values were less than the reporting unit carrying values, accordingly, no "step 1" analysis was required.

In the third quarter of 2018, we determined the Greater Lawrence Incident (see Note 18, "Other Commitments and Contingencies") represented a triggering event that required an impairment analysis of goodwill. This incident specifically impacts our Columbia of Massachusetts reporting unit in which the associated goodwill totaled $204.8 million immediately prior to the incident. We performed a quantitative impairment analysis as of September 30, 2018 and determined that the fair value of the Columbia of Massachusetts reporting unit continues to exceed its carrying value. Therefore, no goodwill impairment charges were recorded in the third quarter of 2018. This interim analysis was performed using then-current cash flow projections reflecting the estimated ongoing impacts of the Greater Lawrence Incident on Columbia of Massachusetts' operations. We also updated other significant inputs to the fair value calculation (e.g. discount rate, market multiples) to reflect then-current market conditions and increased risk and uncertainty resulting from the incident. No additional facts came to light since the third quarter impairment analysis was completed that would indicate it was more likely than not that the fair value of the Columbia of Massachusetts reporting unit would have decreased below its carrying value; therefore no goodwill impairment charges were recorded in the fourth quarter of 2018. We will continue to monitor the impacts of the incident for events that could trigger a new impairment analysis including, but not limited to, unfavorable regulatory outcomes and NTSB investigation results.

Intangible Assets. Our intangible assets, apart from goodwill, consist of franchise rights. Franchise rights were identified as part of the purchase price allocations associated with the acquisition in February 1999 of Columbia of Massachusetts. These amounts were $220.7 million and $231.7 million, net of accumulated amortization of $221.5 million and $210.5 million, at December 31, 2018 and 2017, respectively, and are being amortized on a straight-line basis over forty years from the date of acquisition through 2039. NiSource recorded amortization expense of $11.0 million in 2018, 2017, and 2016 related to its franchise right intangible asset.

7. Asset Retirement Obligations

We have recognized asset retirement obligations associated with various legal obligations including costs to remove and dispose of certain construction materials located within many of our facilities, certain costs to retire pipeline, removal costs for certain underground storage tanks, removal of certain pipelines known to contain PCB contamination, closure costs for certain sites including ash ponds, solid waste management units and a landfill, as well as some other nominal asset retirement obligations. We also have a significant obligation associated with the decommissioning of our two hydro facilities located in Indiana. These hydro facilities have an indeterminate life, and as such, no asset retirement obligation has been recorded.

Changes in our liability for asset retirement obligations for the years 2018 and 2017 are presented in the table below:

(in millions)	**2018**		2017	
Beginning Balance	**$ 268.7**		$ 262.6	
Accretion recorded as a regulatory asset/liability	**11.1**		10.3	
Additions	**63.3**	(1)	2.4	
Settlements	**(5.9)**		(15.6)	
Change in estimated cash flows	**14.8**	(1)	9.0	(2)
Ending Balance	**$ 352.0**		$ 268.7	

(1)In 2018, $59.8 million of additions and $17.7 million of the change in estimated cash flows are attributed to costs associated with refining the CCR compliance plan. See Note 18-D, "Environmental Matters," for additional information on CCRs.
(2)The change in estimated cash flows for 2017 is primarily attributed to changes in estimated costs and settlement timing for electric generating stations and the changes in estimated costs for retirement of gas mains.

Certain non-legal costs of removal that have been, and continue to be, included in depreciation rates and collected in the customer rates of the rate-regulated subsidiaries are classified as "Regulatory liabilities" on the Consolidated Balance Sheets.

8. Regulatory Matters

Regulatory Assets and Liabilities

We follow the accounting and reporting requirements of ASC Topic 980, which provides that regulated entities account for and report assets and liabilities consistent with the economic effect of regulatory rate-making procedures if the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates can be charged and collected from customers. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income or expense are deferred on the balance sheet and are recognized in the income statement as the related amounts are included in customer rates and recovered from or refunded to customers.

Regulatory assets were comprised of the following items:

At December 31, *(in millions)*		**2018**		2017
Regulatory Assets				
Unrecognized pension and other postretirement benefit costs (see Note 11)	**$**	**798.3**	$	733.5
Deferred pension and other postretirement benefit costs (see Note 11)		**74.1**		70.7
Environmental costs (see Note 18-D)		**61.5**		63.4
Regulatory effects of accounting for income taxes (see Note 1-N and Note 10)		**233.1**		238.8
Under-recovered gas and fuel costs (see Note 1-K)		**34.7**		25.5
Depreciation		**209.6**		181.0
Post-in-service carrying charges		**206.6**		173.3
Safety activity costs		**91.7**		66.5
DSM programs		**45.5**		40.0
Bailly Generating Station		**244.3**		—
Other		**238.1**		208.5
Total Regulatory Assets	**$**	**2,237.5**	$	1,801.2

Regulatory liabilities were comprised of the following items:

At December 31, *(in millions)*		**2018**		2017
Regulatory Liabilities				
Over-recovered gas and fuel costs (see Note 1-K)	**$**	**32.0**	$	27.6
Cost of removal (see Note 7)		**1,076.0**		1,096.8
Regulatory effects of accounting for income taxes (see Note 1-O and Note 10)		**1,428.3**		1,563.4
Deferred pension and other postretirement benefit costs (see Note 11)		**62.7**		59.0
Other		**61.0**		48.8
Total Regulatory Liabilities	**$**	**2,660.0**	$	2,795.6

Regulatory assets, including under-recovered gas and fuel cost, of approximately $1,552.6 million as of December 31, 2018 are not earning a return on investment. These costs are recovered over a remaining life of up to 41 years. Regulatory assets of approximately $1,917.1 million include expenses that are recovered as components of the cost of service and are covered by regulatory orders. Regulatory assets of approximately $320.4 million at December 31, 2018, require specific rate action.

Assets:

Unrecognized pension and other postretirement benefit costs. In 2007, we adopted certain updates of ASC 715 which required, among other things, the recognition in other comprehensive income or loss of the actuarial gains or losses and the prior service costs or credits that arise during the period but that are not immediately recognized as components of net periodic benefit costs. Certain subsidiaries defer these gains or losses as a regulatory asset in accordance with regulatory orders or as a result of regulatory precedent, to be recovered through base rates.

Deferred pension and other postretirement benefit costs. Primarily relates to the difference between postretirement expense recorded by certain subsidiaries due to regulatory orders and the postretirement expense recorded in accordance with GAAP. These costs are expected to be collected through future base rates, revenue riders or tracking mechanisms.

Environmental costs. Includes certain recoverable costs of investigating, testing, remediating and other costs related to gas plant sites, disposal sites or other sites onto which material may have migrated. Certain of our companies defer the costs as a regulatory asset in accordance with regulatory orders, to be recovered in future base rates, billing riders or tracking mechanisms.

Regulatory effects of accounting for income taxes. Represents the deferral and under collection of deferred taxes in the rate making process. In prior years, we have lowered customer rates in certain jurisdictions for the benefits of accelerated tax deductions. Amounts are expensed for financial reporting purposes as we recover deferred taxes in the rate making process.

Under-recovered gas and fuel costs. Represents the difference between the costs of gas and fuel and the recovery of such costs in revenue and is used to adjust future billings for such deferrals on a basis consistent with applicable state-approved tariff provisions. Recovery of these costs is achieved through tracking mechanisms.

Depreciation. Represents differences between depreciation expense incurred on a GAAP basis and that prescribed through regulatory order. Significant components of this balance include:

- **Columbia of Ohio depreciation rates**. Prior to 2005, the PUCO-approved depreciation rates for rate-making had been lower than those which would have been utilized if Columbia of Ohio were not subject to regulation resulting in the creation of a regulatory asset. In 2005, the PUCO authorized Columbia of Ohio to revise its depreciation accrual rates for the period beginning January 1, 2005. The revised depreciation rates are now higher than those which would have been utilized if Columbia of Ohio were not subject to regulation allowing for amortization of the previously created regulatory asset. The amount of depreciation that would have been recorded from 2005 through 2018 had Columbia of Ohio not been subject to rate regulation is a cumulative $806.8 million, $92.2 million less than that reflected in rates. The resulting regulatory asset balance was $39.5 million and $49.3 million as of December 31, 2018 and 2017, respectively.

- **Columbia of Ohio IRP and CEP.** Columbia of Ohio also has PUCO approval to defer depreciation and debt-based post-in-service carrying charges (see "*Post-in-service carrying charges"* below) associated with its IRP and CEP. As of December 31, 2018, depreciation of $29.1 million and $76.0 million was deferred for the respective programs. Depreciation deferral balances for the respective programs as of December 31, 2017 were $26.5 million and $49.8 million. Recovery of the IRP depreciation is approved annually through the IRP rider. The equivalent of annual depreciation expense, based on the average life of the related assets, is included in the calculation of the IRP rider approved by the PUCO and billed to customers. Deferred depreciation expense is recognized as the IRP rider is billed to customers. The recovery mechanism for depreciation associated with the CEP is discussed in "Additional Regulatory Matters," below.

- **NIPSCO ECRM.** NIPSCO obtained approval from the IURC to recover certain environmental related costs including operation and maintenance and depreciation expense once the environmental facilities become operational. The ECRM deferred charges represent expenses that will be recovered from customers through an annual ECRM Cost Tracker (ECT) which authorizes the collection of deferred balances over a six month period. Recovery of these costs will continue until such assets are included in rate base through an electric base rate case. Depreciation of $14.4 million and $13.9 million was deferred to a regulatory asset as of December 31, 2018 and 2017, respectively.

- **NIPSCO TDSIC.** NIPSCO obtained approval from the IURC to recover costs for certain system modernization projects outside of a base rate proceeding. Eighty percent of the related costs, including depreciation, property taxes, and debt and equity based carrying charges (see *"Post-in-service carrying charges"* below) are recovered through a semi-annual recovery mechanism. Recovery of these costs will continue through the TDSIC tracker until such assets are included in rate base through a gas or electric base rate case, respectively. The remaining twenty percent of the costs are deferred until the next base rate case. As of December 31, 2018 and 2017, depreciation of $16.5 million and $10.3 million, respectively, was deferred as a regulatory asset.

Post-in-service carrying charges. Represents deferred debt-based carrying charges incurred on certain assets placed into service but not yet included in customer rates. This balance includes:

- **Columbia of Ohio IRP and CEP.** See description of IRP and CEP programs above under the heading "*Depreciation*." As of December 31, 2018 and 2017, Columbia of Ohio had deferred PISCC of $197.1 million and $164.6 million, respectively.

- **NIPSCO TDSIC.** See description of TDSIC program above under the heading "*Depreciation*." Deferral of equity-based carrying charges for the TDSIC program is allowed; however, such amounts are not reflected in regulatory asset balances for financial reporting as equity-based returns do not meet the definition of incurred costs under ASC 980. As of December 31, 2018 and 2017, NIPSCO had deferred PISCC of $9.5 million and $8.7 million, respectively.

Safety activity costs. Represents the difference between costs incurred in eligible safety programs in excess of those being recovered in rates. The eligible cost deferrals represent necessary business expenses incurred in compliance with PHMSA regulations and are targeted to enhance the safety of the pipeline systems. Certain subsidiaries defer the excess costs as a regulatory asset in accordance with regulatory orders and recovery of these costs will be address in future base rate proceedings.

DSM programs. Represents costs associated with Gas Distribution Operations and Electric Operations segments' energy efficiency and conservation programs. Costs are recovered through tracking mechanisms.

Bailly Generating Station. Represents the net book value of Units 7 and 8 of Bailly Generating Station that was retired during 2018. These amounts are currently being amortized at a rate consistent with their inclusion in customer rates.

Liabilities:

Over-recovered gas and fuel costs. Represents the difference between the cost of gas and fuel and the recovery of such costs in revenues, and is the basis to adjust future billings for such refunds on a basis consistent with applicable state-approved tariff provisions. Refunding of these revenues is achieved through tracking mechanisms.

Cost of removal. Represents anticipated costs of removal that have been, and continue to be, included in depreciation rates and collected in customer rates of the rate-regulated subsidiaries for future costs to be incurred.

Regulatory effects of accounting for income taxes. Represents amounts owed to customers for deferred taxes collected at a higher rate than the current statutory rates and liabilities associated with accelerated tax deductions owed to customers that are established during the rate making process. Balance includes excess deferred taxes recorded upon implementation of the TCJA in December 2017, net of amounts amortized during 2018.

Deferred pension and other postretirement benefit costs. Primarily represents cash contributions in excess of postretirement benefit expense that is deferred as a regulatory liability by certain subsidiaries in accordance with regulatory orders.

Cost Recovery and Trackers

Comparability of our line item operating results is impacted by regulatory trackers that allow for the recovery in rates of certain costs such as those described below. Increases in the expenses that are the subject of trackers generally result in a corresponding increase in operating revenues and therefore have essentially no impact on total operating income results.

Certain costs of our operating companies are significant, recurring in nature and generally outside the control of the operating companies. Some states allow the recovery of such costs through cost tracking mechanisms. Such tracking mechanisms allow for abbreviated regulatory proceedings in order for the operating companies to implement charges and recover appropriate costs. Tracking mechanisms allow for more timely recovery of such costs as compared with more traditional cost recovery mechanisms. Examples of such mechanisms include GCR adjustment mechanisms, tax riders, bad debt recovery mechanisms, electric energy efficiency programs, MISO non-fuel costs and revenues, resource capacity charges, federally mandated costs and environmental-related costs.

A portion of the Gas Distribution revenue is related to the recovery of gas costs, the review and recovery of which occurs through standard regulatory proceedings. All states in our operating area require periodic review of actual gas procurement activity to determine prudence and to permit the recovery of prudently incurred costs related to the supply of gas for customers. Our distribution companies have historically been found prudent in the procurement of gas supplies to serve customers.

A portion of the Electric Operations revenue is related to the recovery of fuel costs to generate power and the fuel costs related to purchased power. These costs are recovered through a FAC, a quarterly regulatory proceeding in Indiana.

Infrastructure Replacement and Federally-Mandated Compliance Programs

Certain of our operating companies have completed rate proceedings involving infrastructure replacement or enhancement or are embarking upon regulatory initiatives to replace significant portions of their operating systems that are nearing the end of their useful lives. Each operating company's approach to cost recovery may be unique, given the different laws, regulations and precedent that exist in each jurisdiction.

Columbia of Ohio, IRP - On December 3, 2008, the PUCO issued an order which established Columbia of Ohio's IRP. Pursuant to that order, the IRP provides for recovery of costs resulting from: (1) the maintenance, repair and replacement of customer-owned service lines that have been determined by Columbia of Ohio to present an existing or probable hazard to persons and property; (2) Columbia of Ohio's replacement of cast iron, wrought iron, unprotected coated steel and bare steel pipe and associated company and customer-owned metallic service lines; (3) the replacement of customer-owned natural gas risers identified by the PUCO as prone to failure; and (4) the installation of AMR devices on all residential and commercial meters served by Columbia of Ohio. Recoverable costs include a return on investment, depreciation and property taxes, offset by specified cost savings. Columbia of Ohio's five-year IRP plan renewal was last approved on January 31, 2018 for the years 2018-2022.

NIPSCO Gas and Electric, TDSIC - On April 30, 2013, the Indiana Governor signed Senate Enrolled Act 560, known as the TDSIC statute, into law. Among other provisions, the TDSIC statute provides for cost recovery outside of a base rate proceeding for new or replacement electric and gas transmission, distribution, and storage projects that a public utility undertakes for the purposes of safety, reliability, system modernization or economic development. Provisions of the TDSIC statute require that, among other things, requests for recovery include a seven-year plan of eligible investments. Once the plan is approved by the IURC, eighty percent of eligible costs can be recovered using a periodic rate adjustment mechanism, known as the TDSIC mechanism. Recoverable costs include a return on the investment, including AFUDC, PISCC, operation and maintenance expenses, depreciation and property taxes. The remaining twenty percent of recoverable costs are deferred for future recovery in NIPSCO's next general rate case. The semi-annual rate adjustment mechanism is capped at an annual increase of two percent of total retail revenues.

NIPSCO Electric, ECRM - NIPSCO has approval from the IURC to recover certain environmental related costs through an ECT (environmental cost tracker). Under the ECT, NIPSCO is permitted to recover (1) AFUDC and a return on the capital investment expended by NIPSCO to implement environmental compliance plan projects and (2) related operation and maintenance and depreciation expenses once the environmental facilities become operational.

NIPSCO Gas and Electric, FMCA - The FMCA statute provides for cost recovery outside of a base rate proceeding for projected federally mandated costs. Once the plan is approved by the IURC, eighty percent of eligible costs can be recovered using a periodic rate adjustment mechanism, known as the FMCA mechanism. Recoverable costs include a return on the investment, including AFUDC, PISCC, mandated operation and maintenance expenses, depreciation and property taxes. The remaining twenty percent of recoverable costs are deferred for future recovery in NIPSCO's next general rate case. Actual costs that exceed the projected federally mandated costs of the approved compliance project by more than twenty-five percent shall require specific justification by NIPSCO and specific approval by the IURC before being authorized in the next general rate case.

Columbia of Massachusetts, GSEP - On July 7, 2014, the Governor of Massachusetts signed into law Chapter 149 of the Acts of 2014, an Act Relative to Natural Gas Leaks ("the Act"). The Act authorizes natural gas distribution companies to file a GSEP for capital investments made on or after January 1, 2015, that are not included in the Company's current rate base as determined in the most recent base rate case, with the Massachusetts DPU to (1) address the replacement or improvement of existing aging natural gas pipeline infrastructure to improve public safety or infrastructure reliability, and (2) reduce the lost and unaccounted for natural gas through a reduction in natural gas system leaks. In addition, the Act provides that the Massachusetts DPU may, after review of the plan, allow the proposed estimated costs of the plan into rates as of May 1 of the subsequent year. Recoverable costs include a return on investment, depreciation and property taxes, offset by identified operations and maintenance cost savings. Rates are subject to a capped annual revenue increase of one and a half percent of total annual delivery and cost of gas revenues from sales and transportation, including imputed gas revenues for transportation, for the calendar year preceding the projected GSEP calendar year being filed. At the end of each 12-month period, in May of the subsequent year, Columbia of Massachusetts must file a reconciliation of the amount collected and actual costs. Any over-collection or under-collection balance is passed back to, or recovered from, customers over a 12-month period beginning in November. Once new base rates are established under a base rate proceeding, the GSEP factor is re-set to remove the capital investment and associated revenue reflected in the base rates.

Columbia of Pennsylvania, DSIC - On February 14, 2012, the Governor of Pennsylvania signed into law Act 11 of 2012, which provided a DSIC mechanism for certain utilities to recover costs related to repair, replacement or improvement of eligible distribution property that has not previously been reflected in rates or rate base. Through a DSIC, a utility may recover the fixed costs of eligible infrastructure incurred during the three months ended one month prior to the effective date of the charge, thereby reducing the historical regulatory lag associated with cost recovery through the traditional rate-making process. On March 14, 2013, the Pennsylvania PUC approved Columbia of Pennsylvania's petition to implement a DSIC as of April 1, 2013. Accordingly, Columbia of Pennsylvania is authorized to recover the cost of eligible plant associated with repair, replacement or improvement that was not previously reflected in rate base and has been placed in service during the applicable three-month period. After the initial charge is established, the DSIC is updated quarterly to recover the cost of further plant additions and cannot exceed five percent of distribution revenues. Recoverable costs include a return on investment, exclusive of accumulated deferred income taxes from the calculation of rate base, and depreciation. Once new base rates are established under a base rate proceeding, the DSIC is set to zero. Additionally, the DSIC rate is also reset to zero if, in any quarter, the data reflected in the Columbia of Pennsylvania's most recent quarterly financial earnings report show that the utility will earn an overall rate of return that would exceed the allowable rate of return used to calculate its fixed costs under the DSIC mechanism. A utility is exempt from filing a quarterly financial earnings report when a base rate proceeding is pending before the Pennsylvania PUC.

Columbia of Virginia, SAVE - On March 11, 2010, the Virginia Governor signed legislation into law that allows natural gas utilities to implement programs to replace qualifying infrastructure on an expedited basis and provides for timely cost recovery. Known as the SAVE Act, the law allows natural gas utilities to file programs with the VSCC providing a timeline and estimated costs for replacing eligible infrastructure. Eligible infrastructure replacement projects are those that (1) enhance safety or reliability by reducing system integrity risks associated with customer outages, corrosion, equipment failures, material failures, or natural forces; (2) do not increase revenues by directly connecting the infrastructure replacement to new customers; (3) reduce or have the potential to reduce greenhouse gas emissions; (4) are not included in the natural gas utility's rate base in its most recent rate case; and (5) are commenced on or after January 1, 2010. The SAVE Act provides for recovery of costs associated with the eligible infrastructure through a rate rider. Recoverable costs include a return on investment, depreciation and property taxes. Columbia of Virginia's current five year SAVE plan was approved by the VSCC in 2016 and amended in 2017 for the years 2016 through 2020.

Columbia of Kentucky, AMRP - On October 26, 2009, the Kentucky PSC approved a mechanism for recovering the costs of Columbia of Kentucky's AMRP not previously reflected in rate base through an annual fixed monthly rate rider filed in October. In its 2013 rate case, Columbia of Kentucky was allowed to base the AMRP rider on the expected annual cost of service. Recoverable costs include a return on investment, depreciation and property taxes, offset by specific cost savings. At the end of each 12-month period, Columbia of Kentucky must file a reconciliation of the amount collected and actual costs. Any over-collection or under-collection balance is passed back to, or recovered from, customers through the surcharge over a 12-month period beginning in June of the subsequent year. Once new base rates are established under a base rate proceeding, the AMRP rider is set to zero.

Columbia of Maryland, STRIDE - On May 2, 2013, the Governor of Maryland signed Senate Bill 8 into law, authorizing gas companies to accelerate recovery of eligible infrastructure replacement, effective June 1, 2013. The STRIDE statute provides recovery for gas pipeline upgrades outside of the context of a base rate proceeding through an annual surcharge, IRIS, as approved by, Maryland PSC. The STRIDE statute directs gas utilities to file a plan to invest in eligible infrastructure replacement projects and to list the specific projects and elements in any such STRIDE plan with the Maryland PSC. The calendar year projected capital projects to be placed into plant in service and included in Columbia of Maryland's surcharge recovery request must satisfy a number of criteria per the statute, including a requirement that they be designed to improve public safety or infrastructure reliability. Columbia of Maryland's five-year STRIDE Plan renewal for years 2019 through 2023, as with the preceding five years, is focused on replacing (1) existing cast iron and bare steel mains, (2) associated services and meters, and (3) identified prone-to-failure vintage plastic piping. Columbia of Maryland's IRIS mechanism recovers a return on investment, depreciation and property taxes of the STRIDE-eligible capital infrastructure statutorily capped at $2 per month for residential customers, and proportionally capped for commercial and industrial customer classes, and is reconciled to actual costs on an annual basis. Any over-collection or under-collection balance is passed back to, or recovered from, customers through the surcharge effective in May of the subsequent year.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

The following table describes regulatory programs to recover infrastructure replacement and other federally-mandated compliance investments currently in rates and those pending commission approval:

(in millions)

Company	Program	Incremental Revenue	Incremental Capital Investment	Investment Period	Filed	Status	Rates Effective
Columbia of Ohio	IRP - 2018[1]	$ 2.3	$ 207.0	1/17-12/17	February 27, 2018	Approved April 25, 2018	May 2018
NIPSCO - Gas	TDSIC 7	$ 1.5	$ 59.0	1/17-6/17	August 31, 2017	Approved December 28, 2017	January 2018
NIPSCO - Gas	TDSIC 8	$ 1.8	$ 54.0	7/17-12/17	February 27, 2018	Approved August 22, 2018	September 2018
NIPSCO - Gas	TDSIC 9[1][2]	$ (10.6)	$ 54.4	1/18 - 6/18	August 28, 2018	Approved December 27, 2018	January 2019
NIPSCO - Gas	FMCA 1	$ 9.9	$ 1.5	11/17-9/18	November 30, 2018	Order Expected Q1 2019	April 2019
Columbia of Massachusetts	GSEP - 2018[1][3]	$ 6.5	$ 80.0	1/18-12/18	October 31, 2017	Approved April 30, 2018	May 2018
Columbia of Massachusetts	GSEP - 2019[4]	$ 10.7	$ 64.0	1/19-12/19	October 31, 2018	Order expected Q2 2019	May 2019
Columbia of Pennsylvania	DSIC - 2018	$ 0.4	$ 14.8	12/17-2/18	March 22, 2018	Approved March 29, 2018	April 2018
Columbia of Pennsylvania	DSIC - 2018	$ 0.9	$ 31.8	3/18-5/18	June 20, 2018	Approved June 28, 2018	July 2018
Columbia of Pennsylvania	DSIC - 2018	$ 1.6	$ 55.4	6/18-8/18	September 20, 2018	Approved September 28, 2018	October 2018
Columbia of Virginia	SAVE - 2018	$ 2.9	$ 33.3	1/18-12/18	August 18, 2017	Approved December 13, 2017	January 2018
Columbia of Virginia	SAVE - 2019	$ 2.4	$ 36.0	1/19-12/19	August 17, 2018	Approved October 26, 2018	January 2019
Columbia of Kentucky	AMRP - 2018	$ 4.5	$ 24.0	1/18-12/18	October 13, 2017	Approved December 22, 2017	January 2018
Columbia of Kentucky	AMRP - 2019	$ 3.6	$ 30.1	1/19-12/19	October 15, 2018	Approved December 5, 2018	January 2019
Columbia of Maryland	STRIDE - 2018	$ 1.2	$ 20.8	1/18-12/18	November 1, 2017	Approved December 20, 2017	January 2018
Columbia of Maryland	STRIDE - 2019	$ 1.2	$ 19.7	1/19-12/19	November 1, 2018	Approved December 12, 2018	January 2019
NIPSCO - Electric	TDSIC - 3	$ (2.0)	$ 75.0	5/17-11/17	January 30, 2018	Approved May 30, 2018	June 2018
NIPSCO - Electric	TDSIC - 4[1]	$ (11.8)	$ 72.2	12/17-5/18	July 31, 2018	Approved November 28, 2018	December 2018
NIPSCO - Electric	TDSIC - 5[1]	$ 15.9	$ 58.8	6/18-11/18	January 29, 2019	Order Expected Q2 2019	June 2019
NIPSCO - Electric	ECRM - 31	$ (2.1)	$ 2.9	6/17-12/17	January 31, 2018	Approved April 25, 2018	May 2018
NIPSCO - Electric	ECRM - 32	$ 1.0	$ —	1/18-6/18	July 31, 2018	Approved October 11, 2018	November 2018
NIPSCO - Electric	FMCA - 8	$ 1.3	$ 4.4	4/17-9/17	November 1, 2017	Approved January 31, 2018	February 2018
NIPSCO - Electric	FMCA - 9	$ 4.1	$ 90.2	10/17-3/18	April 27, 2018	Approved July 25, 2018	August 2018
NIPSCO - Electric	FMCA - 10	$ 2.2	$ 45.7	4/18-8/18	October 18, 2018	Approved January 29, 2019	February 2019

[1]Incremental revenue is net of amounts due back to customers as a result of the TCJA.
[2]Incremental revenue is net of $5.2 million of adjustments in the TDSIC-9 settlement.

(3)A cap waiver was approved by the Massachusetts DPU on June 21, 2018 and related rates became effective July 2018.
(4)The filing included a request for approval of a waiver to allow collection of the $2.9 million revenue requirement that exceeds the GSEP cap provision.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

Rate Case Actions

The following table describes current rate case actions as applicable in each of our jurisdictions net of tracker impacts:

(in millions)

Company	Requested Incremental Revenue	Approved Incremental Revenue	Filed	Status	Rates Effective
NIPSCO - Gas[1]	$ 138.1	$ 107.3	September 27, 2017	Approved September 19, 2018	October 2018
Columbia of Massachusetts	$ 24.1	N/A	April 13, 2018	Withdrawn September 19, 2018	N/A
Columbia of Pennsylvania	$ 46.9	$ 26.0	March 16, 2018	Approved December 6, 2018	December 2018
Columbia of Virginia[2]	$ 14.2	In process	August 28, 2018	Order expected Second half of 2019	February 2019
Columbia of Maryland	$ 4.6	$ 2.2	April 13, 2018	Approved November 21, 2018	November 2018
NIPSCO - Electric	$ 21.4	In process	October 31, 2018	Order expected Q3 2019	September 2019

[1]Rates will be implemented in three steps, with implementation of step 1 rates effective October 1, 2018. Step 2 rates will be effective on or about March 1, 2019, and step 3 rates will be effective on January 1, 2020. The IURC's order also dismissed NIPSCO from phase 2 of the IURC's TCJA investigation.
[2]Rates implemented subject to refund pending a final order from the VSCC.

Additional Regulatory Matters

Columbia of Ohio. On December 1, 2017, Columbia of Ohio filed an application that requested authority to implement a rider to begin recovering plant and associated deferrals related to its CEP. The CEP was established in 2011 and allows for deferral of interest, depreciation and property taxes on certain plant investments not recovered through its IRP modernization tracker. The application requested authority to increase annual revenues, through the requested rider, by approximately $70 million, with biennial increases up to approximately $98 million in 2022. On May 9, 2018, the PUCO appointed an independent auditor to assist the PUCO with the review of the accounting accuracy, prudency and compliance of Columbia of Ohio with its PUCO-approved CEP deferrals. The independent audit report was filed on September 4, 2018 and the PUCO Staff's Report on the investigation was filed on September 14, 2018. On October 25, 2018, a joint stipulation and recommendation was filed recommending an initial revenue requirement of $74.5 million to recover CEP investments and deferrals through December 31, 2017, with annual adjustments for capital investments made in subsequent years. Additionally, the signatory parties to the stipulation agreed to a reduction in rates to adjust for the impacts of the TCJA and for a base rate case filing to be made by Columbia of Ohio with a test period of calendar year 2021. On November 28, 2018 the PUCO issued an order unanimously approving the settlement filed on October 25, 2018, without modification, for rates effective beginning November 29, 2018. This order finalizes Columbia of Ohio's TCJA resolution related to the CEP tracker, as well as base rates.

NIPSCO Gas. On November 8, 2017, NIPSCO filed a petition with the IURC seeking approval of NIPSCO's federally mandated pipeline safety compliance plan. As part of the settlement agreement filed in NIPSCO's gas base rate case proceeding, NIPSCO and the parties to the settlement agreement settled all issues in this proceeding as well, including moving certain costs from the base rate proceeding to this pipeline safety compliance plan. The updated four year compliance plan includes a total estimated $91.5 million of capital costs and $35.5 million of expected operating and maintenance costs. NIPSCO received approval for accounting and rate-making relief, including establishment of a periodic rate adjustment mechanism. NIPSCO filed the first tracker proceeding in this case on November 30, 2018. On December 31, 2018, NIPSCO filed a petition with the IURC seeking approval of an additional PHMSA compliance plan including capital expenditures of $228.8 million. An IURC order is expected in the second half of 2019.

On January 3, 2018, the IURC initiated an investigation to review and consider the possible implications of the TCJA on utility rates. The IURC ordered a two phase investigation. Phase 1 solely dealt with the prospective changes in rates to reflect the change in tax rates. In accordance with the procedural schedule, on March 26, 2018, NIPSCO filed revised gas tariffs reflecting the impact of the change in tax rate for its applicable rates and charges. The IURC approved NIPSCO's Phase 1 filing on April 26, 2018. The revised tariffs were effective May 1, 2018. The stipulation and settlement agreement filed on April 20, 2018, in NIPSCO's gas rate case resolved all issues in Phase 2, including the return of excess income tax revenue recovered through its base rates and any applicable charges between January 1, 2018 and April 30, 2018. Beginning January 2019, and continuing through June 2019, NIPSCO is passing back the excess tax expense through the TDSIC mechanism.

On December 27, 2018, the IURC issued an order for TDSIC-9 approving the settlement agreement filed on November 4, 2018. This order, along with the Court of Appeals dismissal on December 31, 2018 and January 8, 2019, resolved all outstanding issues related to the appeals of TDSIC-4 though TDSIC-8.

Columbia of Massachusetts. On October 9, 2018, Columbia of Massachusetts filed an application with the Massachusetts DPU, seeking authority to pass back approximately $95.8 million in excess deferred taxes associated with TCJA with an effective date of rates to be determined by the Massachusetts DPU. On December 21, 2018 the Massachusetts DPU issued an order approving the treatment of TCJA-related excess deferred taxes. Columbia Gas of Massachusetts filed a compliance filing on January 4, 2019, reflecting revised LDAF rates inclusive of credit factors to return excess deferred taxes associated with TCJA to customers for rates effective on February 1, 2019, per the Massachusetts DPU's order.

Columbia of Kentucky. On April 30, 2018, Columbia of Kentucky received an order from the Kentucky PSC requiring implementation of interim proposed rates effective May 1, 2018 reflecting the impact of TCJA subject to future adjustment. The order directed Columbia of Kentucky to file, by September 1, 2018, revised TCJA adjustment factors reflecting the tax expense savings from January 1, 2018 through April 30, 2018, and an estimate of the annual reduction due to the excess deferred taxes to be effective with the first billing cycle of October 2018. On August 31, 2018, Columbia of Kentucky filed updated rate schedules with the Kentucky PSC for rates proposed to be effective October 1, 2018. On October 25, 2018, the Kentucky PSC authorized the TCJA adjustment factors, as proposed, with an October 29, 2018 effective date to pass-back the overcollection of taxes over a six month period.

Columbia of Maryland. On February 13, 2018, Columbia of Maryland filed a proposal with the Maryland PSC to reduce rates as a result of TCJA with an annual revenue decrease of $1.3 million. Columbia of Maryland was directed to account for any revenues associated with the difference between previous and current income tax rates and excess deferred taxes as regulatory liabilities effective January 1, 2018. On March 14, 2018, Columbia of Maryland received approval, effective April 2, 2018, to implement new rates and pass-back the overcollection of taxes from the first quarter of 2018 over a seven month period.

NIPSCO Electric. On October 31, 2018, NIPSCO submitted its 2018 Integrated Resource Plan with the IURC. The plan evaluated demand-side and supply-side resource alternatives to reliably and cost effectively meet NIPSCO customers' future energy requirements over the ensuing 20 years. Refer to Note 18-E, "Other Matters," in the Notes to Consolidated Financial Statements for additional information.

On March 29, 2018, WCE, which is currently owned by BP p.l.c ("BP") and BP Products North America, which operates the BP Refinery, filed a petition at the IURC asking that the combined operations of WCE and BP be treated as a single premise, and the WCE generation be dedicated primarily to BP Refinery operations beginning in May 2019 as WCE has self-certified as a qualifying facility at FERC. BP Refinery planned to continue to purchase electric service from NIPSCO at a reduced demand level beginning in May 2019. A settlement agreement was filed on November 2, 2018 agreeing that BP and WCE would not move forward with construction of a private transmission line to serve BP until conclusion of NIPSCO's pending electric rate case.

On February 1, 2018, NIPSCO and certain other MISO transmission owners filed with the FERC a request for waiver of tariff provisions to allow for implementation of TCJA tax rate change provisions into 2018 transmission formula rates. On March 15, 2018, the FERC issued an order granting the request for waiver and set the effective date of the waiver at January 1, 2018. In the March billing cycle, the MISO began billing the new transmission rates reflecting the lower federal tax rate. In addition, the MISO began to re-bill January and February 2018 affected revenues and costs in the March 2018 billing cycle, and completed the re-settlement in the April 2018 billing cycle. The new 2018 transmission formula rates will reduce revenue by $8.5 million in 2018 associated with NIPSCO's multi-value projects. Additionally, on November 1, 2018, MISO submitted revised tariffs to provide for adjustments to income tax, including accumulated deferred income tax, resulting from tax law or rate changes. On December 20, 2018, FERC accepted the submission, effective January 1, 2019, as requested.

As noted above in the NIPSCO Gas regulatory matters, the IURC initiated an investigation on January 3, 2018, to review and consider the implications of the TCJA on utility rates. The commission ordered a two phase investigation. Phase 1 solely dealt with the prospective changes in rates to reflect the change in tax rates. On March 26, 2018, NIPSCO filed revised electric tariffs reflecting the impact of the change in tax rate for its applicable rates and charges. The IURC approved NIPSCO's phase 1 filing on April 26, 2018. The revised tariffs were effective May 1, 2018. On July 31, 2018, NIPSCO filed an unopposed motion requesting that the over-collection of income taxes from January 1, 2018 through April 30, 2018 be passed back in NIPSCO's TDSIC-4 filing, also filed on July 31, 2018, and requesting that all other phase 2 issues be handled in a rate case filing to be made in the fourth quarter of 2018. On August 15, 2018, the IURC approved the motion to pass back the over-collection through the TDSIC-4 rates effective December 2018 through May 2019. All other phase 2 issues are addressed in the base rate case filed October 31, 2018.

9. Risk Management Activities

We are exposed to certain risks relating to ongoing business operations; namely commodity price risk and interest rate risk. We recognize that the prudent and selective use of derivatives may help to lower our cost of debt capital, manage interest rate exposure and limit volatility in the price of natural gas.

Risk management assets and liabilities on our derivatives are presented on the Consolidated Balance Sheets as shown below:

December 31, *(in millions)*	**2018**	2017
Risk Management Assets - Current[1]		
Interest rate risk programs	**$ —**	$ 14.0
Commodity price risk programs	**1.1**	0.5
Total	**$ 1.1**	$ 14.5
Risk Management Assets - Noncurrent[2]		
Interest rate risk programs	**$ 18.5**	$ 5.6
Commodity price risk programs	**4.4**	1.0
Total	**$ 22.9**	$ 6.6
Risk Management Liabilities - Current		
Interest rate risk programs	**$ —**	$ 38.6
Commodity price risk programs	**5.0**	4.6
Total	**$ 5.0**	$ 43.2
Risk Management Liabilities - Noncurrent		
Interest rate risk programs	**$ 9.5**	$ —
Commodity price risk programs	**37.2**	28.5
Total	**$ 46.7**	$ 28.5

[1]Presented in "Prepayments and other" on the Consolidated Balance Sheets.
[2]Presented in "Deferred charges and other" on the Consolidated Balance Sheets.

Commodity Price Risk Management
We, along with our utility customers, are exposed to variability in cash flows associated with natural gas purchases and volatility in natural gas prices. We purchase natural gas for sale and delivery to our retail, commercial and industrial customers, and for most customers the variability in the market price of gas is passed through in their rates. Some of our utility subsidiaries offer programs whereby variability in the market price of gas is assumed by the respective utility. The objective of our commodity price risk programs is to mitigate the gas cost variability, for us or on behalf of our customers, associated with natural gas purchases or sales by economically hedging the various gas cost components using a combination of futures, options, forwards or other derivative contracts.

NIPSCO received IURC approval to lock in a fixed price for its natural gas customers using long-term forward purchase instruments. The term of these instruments range from five to ten years and is limited to twenty percent of NIPSCO's average annual GCA purchase volume. Gains and losses on these derivative contracts are deferred as regulatory liabilities or assets and are remitted to or collected from customers through NIPSCO's quarterly GCA mechanism. These instruments are not designated as accounting hedges.

Interest Rate Risk Management
As of December 31, 2018, we have forward-starting interest rate swaps with an aggregate notional value totaling $500.0 million to hedge the variability in cash flows attributable to changes in the benchmark interest rate during the periods from the effective dates of the swaps to the anticipated dates of forecasted debt issuances, which are expected to take place by the end of 2024. These interest rate swaps are designated as cash flow hedges. The effective portions of the gains and losses related to these swaps are

recorded to AOCI and are recognized in "Interest expense, net" concurrently with the recognition of interest expense on the associated debt, once issued. If it becomes probable that a hedged forecasted transaction will no longer occur, the accumulated gains or losses on the derivative will be recognized currently in "Other, net" in the Statements of Consolidated Income (Loss).

The passage of the TCJA and Greater Lawrence Incident led to significant changes to our long-term financing plan. As a result, during 2018, we settled forward-starting interest rate swaps with a notional value of $750.0 million. These derivative contracts were accounted for as cash flow hedges. As part of the transactions, the associated net unrealized gain of $46.2 million was recognized immediately in "Other, net" on the Statements of Consolidated Income (Loss) due to the probability associated with the forecasted borrowing transactions no longer occurring.

There were no amounts excluded from effectiveness testing for derivatives in cash flow hedging relationships at December 31, 2018, 2017 and 2016.

Our derivative instruments measured at fair value as of December 31, 2018 and 2017 do not contain any credit-risk-related contingent features.

10. Income Taxes

On December 22, 2017, the President signed into law the TCJA, which, among other things, enacted significant changes to the Internal Revenue Code, as amended, including a reduction in the maximum U.S. federal corporate income tax rate from 35% to 21%, and certain other provisions related specifically to the public utility industry, including the continuation of certain interest expense deductibility. These changes were effective January 1, 2018. Under GAAP, the effects of a change in tax law are recorded as a discrete item in the period of enactment.

Rates for our regulated customers include provisions for the collection of U.S. federal income taxes. Accordingly, accounting effects related to changes in tax rates here that would normally be recognized as a component of income tax expense may instead be deferred as a regulatory asset or liability and reflected in future rate-making. In December 2017, we remeasured our deferred tax assets and liabilities to the new federal corporate income tax rate. The result of this remeasurement was a reduction in the net deferred tax liability of approximately $1.3 billion, including approximately $0.4 billion of regulatory "gross up" to account for over-collection of past taxes from customers. Offsetting the reduction in net deferred tax liabilities was an increase in regulatory liabilities of approximately $1.5 billion and an increase in income tax expense of $0.2 billion. In 2018, we received regulatory orders from most of the jurisdictions in which we operate regarding the treatment and pass back of excess deferred taxes. As a result of these orders we reduced our regulatory liability related to excess deferred income taxes by $120.7 million (net of tax). This adjustment is reflected in "Income Taxes" on our Consolidated Statements of Income (Loss).

On December 22, 2017, the SEC issued Staff Accounting Bulletin 118 (“SAB 118”), which provides guidance on accounting for tax effects of the TCJA. SAB 118 provides a measurement period that should not extend beyond one year from the TCJA enactment date for companies to complete the accounting under ASC 740. There were no adjustments recorded in the SAB 118 remeasurement period in 2018.

The components of income tax expense (benefit) were as follows:

Year Ended December 31, *(in millions)*	**2018**	2017	2016
Income Taxes			
Current			
Federal	**$ —**	$ —	$ —
State	**8.2**	7.8	(0.1)
Total Current	**8.2**	7.8	(0.1)
Deferred			
Federal	**(209.4)**	302.7	165.6
State	**22.2**	5.0	18.0
Total Deferred	**(187.2)**	307.7	183.6
Deferred Investment Credits	**(1.0)**	(1.0)	(1.4)
Income Taxes	**$ (180.0)**	$ 314.5	$ 182.1

Total income taxes were different from the amount that would be computed by applying the statutory federal income tax rate to book income before income tax. The major reasons for this difference were as follows:

Year Ended December 31, *(in millions)*	**2018**		2017		2016	
Book income (loss) before income taxes	**$ (230.6)**		$ 443.0		$ 513.6	
Tax expense (benefit) at statutory federal income tax rate	**(48.4)**	**21.0 %**	155.0	35.0 %	179.8	35.0 %
Increases (reductions) in taxes resulting from:						
State income taxes, net of federal income tax benefit	**24.7**	**(10.7)**	6.9	1.5	11.3	2.2
Amortization of regulatory liabilities	**(29.3)**	**12.7**	(2.4)	(0.5)	(1.5)	(0.3)
Charitable contribution carryover	**—**	**—**	(1.2)	(0.3)	2.8	0.5
State regulatory proceedings	**(127.8)**	**55.4**	—	—	—	—
Remeasurement due to TCJA	**—**	**—**	161.1	36.4	—	—
Employee stock ownership plan dividends and other compensation	**(2.2)**	**1.0**	(6.5)	(1.5)	(9.5)	(1.8)
Other adjustments	**3.0**	**(1.3)**	1.6	0.4	(0.8)	(0.1)
Income Taxes	**$ (180.0)**	**78.1 %**	$ 314.5	71.0 %	$ 182.1	35.5 %

The effective income tax rates were 78.1%, 71.0% and 35.5% in 2018, 2017 and 2016, respectively. The 7.1% increase in the overall effective tax rate in 2018 versus 2017 was primarily the result of state regulatory proceedings which resulted in a $127.8 million decrease in federal income taxes offset by a related increase in state income taxes of $7.1 million. Additionally, the increase was driven by a $26.9 million decrease in income taxes related to amortization of the regulatory liability primarily associated with excess deferred taxes.

The 35.5% increase in the overall effective tax rate in 2017 versus 2016 was primarily the result of a $161.1 million increase in income taxes related to implementing the provisions of the TCJA. The charge to income tax expense resulting from implementation of the TCJA relates primarily to remeasurement of parent company deferred tax assets for NOL carryforwards.

In March 2016, the FASB issued ASU 2016-09, Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting. Among other provisions, the standard requires that all income tax effects of awards are recognized in the income statement when the awards vest and are distributed.

Deferred income taxes result from temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. The principal components of our net deferred tax liability were as follows:

At December 31, *(in millions)*	**2018**	2017
Deferred tax liabilities		
Accelerated depreciation and other property differences	**$ 2,458.0**	$ 2,260.7
Other regulatory assets	**375.4**	309.5
Total Deferred Tax Liabilities	**2,833.4**	2,570.2
Deferred tax assets		
Other regulatory liabilities and deferred investment tax credits (including TCJA)	**365.5**	406.0
Pension and other postretirement/postemployment benefits	**157.5**	136.7
Net operating loss carryforward and AMT credit carryforward	**849.8**	576.0
Environmental liabilities	**24.4**	24.0
Other accrued liabilities	**37.5**	37.2
Other, net	**68.2**	97.4
Total Deferred Tax Assets	**1,502.9**	1,277.3
Net Deferred Tax Liabilities	**$ 1,330.5**	$ 1,292.9

State income tax net operating loss benefits are recorded at their realizable value. We anticipate it is more likely than not that we will realize $88.5 million and $65.8 million of these tax benefits as of December 31, 2018 and 2017, respectively, prior to their expiration. These tax benefits are primarily related to Indiana, Massachusetts and Pennsylvania. The remaining net operating loss carryforward tax benefits represent a federal carryforward of $759.6 million ($508.5 million of which relates to years prior to the implementation of the TCJA) and an Alternative Minimum Tax credit of $1.7 million. The carryforward periods for pre-TCJA tax benefits expire in various tax years from 2028 to 2037. Per the TCJA, federal NOL carryforwards generated after December 31, 2017 do not expire, but are limited to 80% of current year taxable income.

Unrecognized tax benefits for the periods reported are immaterial. We present accrued interest on unrecognized tax benefits, accrued interest on other income tax liabilities and tax penalties in "Income Taxes" on our Statements of Consolidated Income (Loss). Interest expense recorded on unrecognized tax benefits and other income tax liabilities was immaterial for all periods presented. There were no accruals for penalties recorded in the Statements of Consolidated Income (Loss) for the years ended December 31, 2018, 2017 and 2016, and there were no balances for accrued penalties recorded on the Consolidated Balance Sheets as of December 31, 2018 and 2017.

We are subject to income taxation in the United States and various state jurisdictions; primarily Indiana, Pennsylvania, Kentucky, Massachusetts, Maryland and Virginia.

We participate in the IRS CAP which provides the opportunity to resolve tax matters with the IRS before filing each year's consolidated federal income tax return. As of December 31, 2018, tax years through 2017 have been audited and are effectively closed to further assessment. The audit of tax year 2018 under the CAP program is expected to be completed in 2019.

The statute of limitations in each of the state jurisdictions in which we operate remains open until the years are settled for federal income tax purposes, at which time amended state income tax returns reflecting all federal income tax adjustments are filed. As of December 31, 2018, there were no state income tax audits in progress that would have a material impact on the consolidated financial statements.

11. Pension and Other Postretirement Benefits

We provide defined contribution plans and noncontributory defined benefit retirement plans that cover certain of our employees. Benefits under the defined benefit retirement plans reflect the employees' compensation, years of service and age at retirement. Additionally, we provide health care and life insurance benefits for certain retired employees. The majority of employees may become eligible for these benefits if they reach retirement age while working for us. The expected cost of such benefits is accrued during the employees' years of service. Current rates of rate-regulated companies include postretirement benefit costs, including amortization of the regulatory assets that arose prior to inclusion of these costs in rates. For most plans, cash contributions are remitted to grantor trusts.

Our Pension and Other Postretirement Benefit Plans' Asset Management. We employ a liability-driven investing strategy for the pension plan, as noted below. A mix of equities and fixed income investments are used to maximize the long-term return of plan assets and hedge the liabilities at a prudent level of risk. We utilize a total return investment approach for the other postretirement benefit plans. Risk tolerance is established through careful consideration of plan liabilities, plan funded status, and asset class volatility. The investment portfolio contains a diversified blend of equity and fixed income investments. Furthermore, equity investments are diversified across U.S. and non-U.S. stocks, as well as growth, value, small and large capitalizations. Other assets such as private equity funds are used judiciously to enhance long-term returns while improving portfolio diversification. Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives may not be used to leverage the portfolio beyond the market value of the underlying assets. Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

We utilize a building block approach with proper consideration of diversification and rebalancing in determining the long-term rate of return for plan assets. Historical markets are studied and long-term historical relationships between equities and fixed income are analyzed to ensure that they are consistent with the widely accepted capital market principle that assets with higher volatility generate greater return over the long run. Current market factors, such as inflation and interest rates, are evaluated before long-term capital market assumptions are determined. Peer data and historical returns are reviewed to check for reasonability and appropriateness.

The most important component of an investment strategy is the portfolio asset mix, or the allocation between the various classes of securities available to the pension and other postretirement benefit plans for investment purposes. The asset mix and acceptable minimum and maximum ranges established for our plan assets represents a long-term view and are listed in the table below.

In 2012, a dynamic asset allocation policy for the pension fund was approved. This policy calls for a gradual reduction in the allocation of return-seeking assets (equities, real estate and private equity) and a corresponding increase in the allocation of liability-hedging assets (fixed income) as the funded status of the plans increase above 90% (as measured by the market value of qualified pension plan assets divided by the projected benefit obligations of the qualified pension plans). During 2017, a $277 million discretionary contribution was made to the pension plans. A new asset-liability study was completed in 2018 resulting in a more conservative glide path and an increase in the allocation to liability-hedging assets held in the portfolio.

As of December 31, 2018, the asset mix and acceptable minimum and maximum ranges established by the policy for the pension and other postretirement benefit plans are as follows:

Asset Mix Policy of Funds:

	Defined Benefit Pension Plan		Postretirement Benefit Plan	
Asset Category	Minimum	Maximum	Minimum	Maximum
Domestic Equities	12%	32%	0%	55%
International Equities	6%	16%	0%	25%
Fixed Income	59%	71%	20%	100%
Real Estate	0%	7%	0%	0%
Short-Term Investments/Other	0%	15%	0%	10%

As of December 31, 2017, the asset mix and acceptable minimum and maximum ranges established by the policy for the pension and other postretirement benefit plans were as follows:

Asset Mix Policy of Funds:

	Defined Benefit Pension Plan		Postretirement Benefit Plan	
Asset Category	Minimum	Maximum	Minimum	Maximum
Domestic Equities	16%	36%	0%	55%
International Equities	8%	18%	0%	25%
Fixed Income	39%	51%	20%	100%
Diversified Credit	0%	13%	0%	0%
Real Estate	0%	13%	0%	0%
Short-Term Investments	0%	10%	0%	10%

Pension Plan and Postretirement Plan Asset Mix at December 31, 2018 and December 31, 2017:

	Defined Benefit Pension Assets	December 31, 2018	Postretirement Benefit Plan Assets	December 31, 2018
Asset Class *(in millions)*	Asset Value	% of Total Assets	Asset Value	% of Total Assets
Domestic Equities	$ 355.5	19.0%	$ 78.8	36.4%
International Equities	165.5	8.9%	17.5	8.1%
Fixed Income	1,241.9	66.5%	115.1	53.2%
Real Estate	52.7	2.8%	—	—
Cash/Other	52.1	2.8%	4.9	2.3%
Total	$ 1,867.7	100.0%	$ 216.3	100.0%

	Defined Benefit Pension Assets	December 31, 2017	Postretirement Benefit Plan Assets	December 31, 2017
Asset Class *(in millions)*	Asset Value	% of Total Assets	Asset Value	% of Total Assets
Domestic Equities	$ 698.2	32.3%	$ 96.0	36.6%
International Equities	351.0	16.2%	39.8	15.2%
Fixed Income	977.6	45.3%	117.5	44.8%
Real Estate	49.9	2.3%	—	—
Cash/Other	83.3	3.9%	9.2	3.4%
Total	$ 2,160.0	100.0%	$ 262.5	100.0%

The categorization of investments into the asset classes in the table above are based on definitions established by our Benefits Committee.

Fair Value Measurements. The following table sets forth, by level within the fair value hierarchy, the Master Trust and other postretirement benefits investment assets at fair value as of December 31, 2018 and 2017. Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Total Master Trust and other postretirement benefits investment assets at fair value classified within Level 3 were \$86.1 million and \$98.9 million as of December 31, 2018 and December 31, 2017, respectively. Such amounts were approximately 4% of the Master Trust and other postretirement benefits' total investments as reported on the statement of net assets available for benefits at fair value as of December 31, 2018 and 2017.

Valuation Techniques Used to Determine Fair Value:

Level 1 Measurements

Most common and preferred stocks are traded in active markets on national and international securities exchanges and are valued at closing prices on the last business day of each period presented. Cash is stated at cost which approximates fair value, with the exception of cash held in foreign currencies which fluctuates with changes in the exchange rates. Short-term bills and notes are priced based on quoted market values.

Level 2 Measurements

Most U.S. Government Agency obligations, mortgage/asset-backed securities, and corporate fixed income securities are generally valued by benchmarking model-derived prices to quoted market prices and trade data for identical or comparable securities. To the extent that quoted prices are not available, fair value is determined based on a valuation model that includes inputs such as interest rate yield curves and credit spreads. Securities traded in markets that are not considered active are valued based on quoted market prices, broker or dealer quotations, or alternative pricing sources with reasonable levels of price transparency. Other fixed income includes futures and options which are priced on bid valuation or settlement pricing.

Level 3 Measurements

Private equity investment strategies include buy-out, venture capital, growth equity, distressed debt, and mezzanine debt. Private equity investments are held through limited partnerships.

Limited partnerships are valued at estimated fair market value based on their proportionate share of the partnership's fair value as recorded in the partnerships' audited financial statements. Partnership interests represent ownership interests in private equity funds and real estate funds. Real estate partnerships invest in natural resources, commercial real estate and distressed real estate. The fair value of these investments is determined by reference to the funds' underlying assets, which are principally securities, private businesses, and real estate properties. The value of interests held in limited partnerships, other than securities, is determined by the general partner, based upon third-party appraisals of the underlying assets, which include inputs such as cost, operating results, discounted cash flows and market based comparable data. Private equity and real estate limited partnerships typically call capital over a three to five year period and pay out distributions as the underlying investments are liquidated. The typical expected life of these limited partnerships is 10-15 years and these investments typically cannot be redeemed prior to liquidation.

Not Classified

Commingled funds that hold underlying investments that have prices which are derived from the quoted prices in active markets are not classified within the fair value hierarchy. Instead, these assets are measured at estimated fair value using the net asset value per share of the investments. The funds' underlying assets are principally marketable equity and fixed income securities. Units held in commingled funds are valued at the unit value as reported by the investment managers.

For the year ended December 31, 2018, there were no significant changes to valuation techniques to determine the fair value of our pension and other postretirement benefits' assets.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

Fair Value Measurements at December 31, 2018:

(in millions)	December 31, 2018	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Pension plan assets:				
Cash	$ 9.2	$ 8.8	$ 0.4	$ —
Equity securities				
U.S. equities	0.2	0.2	—	—
Fixed income securities				
Government	250.2	—	250.2	—
Corporate	442.8	—	442.8	—
Mutual Funds				
U.S. multi-strategy	110.3	110.3	—	—
International equities	43.2	43.2	—	—
Fixed income	166.8	166.8	—	—
Private equity limited partnerships				
U.S. multi-strategy[(1)]	18.5	—	—	18.5
International multi-strategy[(2)]	12.5	—	—	12.5
Distressed opportunities	2.4	—	—	2.4
Real estate	52.7	—	—	52.7
Commingled funds[(3)]				
Short-term money markets	18.3	—	—	—
U.S. equities	245.2	—	—	—
International equities	122.3	—	—	—
Fixed income	365.7	—	—	—
Pension plan assets subtotal	1,860.3	329.3	693.4	86.1
Other postretirement benefit plan assets:				
Mutual funds				
U.S. equities	68.4	68.4	—	—
International equities	17.5	17.5	—	—
Fixed income	114.8	114.8	—	—
Commingled funds[(3)]				
Short-term money markets	5.2	—	—	—
U.S. equities	10.4	—	—	—
Other postretirement benefit plan assets subtotal	216.3	200.7	—	—
Due to brokers, net[(4)]	(1.1)	—	(1.1)	—
Accrued income/dividends	8.6	8.6	—	—
Total pension and other postretirement benefit plan assets	$ 2,084.1	$ 538.6	$ 692.3	$ 86.1

(1) This class includes limited partnerships/fund of funds that invest in a diverse portfolio of private equity strategies, including buy-outs, venture capital, growth capital, special situations and secondary markets, primarily inside the United States.
(2) This class includes limited partnerships/fund of funds that invest in diverse portfolio of private equity strategies, including buy-outs, venture capital, growth capital, special situations and secondary markets, primarily outside the United States.
(3) This class of investments is measured at fair value using the net asset value per share and has not been classified in the fair value hierarchy.
(4) This class represents pending trades with brokers.

The table below sets forth a summary of changes in the fair value of the Plan's Level 3 assets for the year ended December 31, 2018:

	Balance at January 1, 2018	Total gains or losses (unrealized / realized)	Purchases	(Sales)	Balance at December 31, 2018
Private equity limited partnerships					
U.S. multi-strategy	26.7	2.4	0.7	(11.3)	18.5
International multi-strategy	19.1	(0.6)	—	(6.0)	12.5
Distressed opportunities	3.2	(0.8)	—	—	2.4
Real estate	49.9	1.7	1.8	(0.7)	52.7
Total	$ 98.9	$ 2.7	$ 2.5	$ (18.0)	$ 86.1

The table below sets forth a summary of unfunded commitments, redemption frequency and redemption notice periods for certain investments that are measured at fair value using the net asset value per share for the year ended December 31, 2018:

(in millions)	Fair Value	Redemption Frequency	Redemption Notice Period
Commingled Funds			
Short-term money markets	$ 23.5	Daily	1 day
U.S. equities	255.6	Monthly	3 days
International equities	122.3	Monthly	10-30 days
Fixed income	365.7	Monthly	3 days
Total	$ 767.1		

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

Fair Value Measurements at December 31, 2017:

(in millions)	December 31, 2017	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Pension plan assets:				
Cash	$ 9.7	$ 9.7	$ —	$ —
Equity securities				
U.S. equities	0.3	0.3	—	—
Fixed income securities				
Government	143.4	—	143.4	—
Corporate	332.6	—	332.6	—
Mutual Funds				
U.S. multi-strategy	231.5	231.5	—	—
International equities	85.8	85.8	—	—
Fixed income	242.3	242.3	—	—
Private equity limited partnerships				
U.S. multi-strategy[(1)]	26.7	—	—	26.7
International multi-strategy[(2)]	19.1	—	—	19.1
Distressed opportunities	3.2	—	—	3.2
Real Estate	49.9	—	—	49.9
Commingled funds[(3)]				
Short-term money markets	34.1	—	—	—
U.S. equities	466.6	—	—	—
International equities	265.1	—	—	—
Fixed income	244.9	—	—	—
Pension plan assets subtotal	2,155.2	569.6	476.0	98.9
Other postretirement benefit plan assets:				
Mutual funds				
U.S. equities	83.8	83.8	—	—
International equities	39.8	39.8	—	—
Fixed income	117.3	117.3	—	—
Commingled funds[(3)]				
Short-term money markets	9.4	—	—	—
U.S. equities	12.2	—	—	—
Other postretirement benefit plan assets subtotal	262.5	240.9	—	—
Due to brokers, net[(4)]	(2.5)	—	—	—
Accrued investment income/dividends	7.3	—	—	—
Total pension and other postretirement benefit plan assets	$ 2,422.5	$ 810.5	$ 476.0	$ 98.9

(1) This class includes limited partnerships/fund of funds that invest in a diverse portfolio of private equity strategies, including buy-outs, venture capital, growth capital, special situations and secondary markets, primarily inside the United States.
(2) This class includes limited partnerships/fund of funds that invest in a diverse portfolio of private equity strategies, including buy-outs, venture capital, growth capital, special situations and secondary markets, primarily outside the United States.
(3) This class of investments is measured at fair value using the net asset value per share and has not been classified in the fair value hierarchy.
(4) This class represents pending trades with brokers.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

The table below sets forth a summary of changes in the fair value of the Plan's Level 3 assets for the year ended December 31, 2017:

	Balance at January 1, 2017	Total gains or losses (unrealized / realized)	Purchases	(Sales)	Balance at December 31, 2017
Fixed income securities					
Other fixed income	$ 0.1	$ (0.1)	$ —	$ —	$ —
Private equity limited partnerships					
U.S. multi-strategy	34.8	2.1	0.9	(11.1)	26.7
International multi-strategy	24.9	1.1	0.1	(7.0)	19.1
Distress opportunities	4.1	0.4	—	(1.3)	3.2
Real estate	9.2	(0.6)	42.1	(0.8)	49.9
Total	$ 73.1	$ 2.9	$ 43.1	$ (20.2)	$ 98.9

The table below sets forth a summary of unfunded commitments, redemption frequency and redemption notice periods for certain investments that are measured at fair value using the net asset value per share for the year ended December 31, 2017:

(in millions)	Fair Value	Redemption Frequency	Redemption Notice Period
Commingled Funds			
Short-term money markets	$ 43.5	Daily	1 day
U.S. equities	478.8	Monthly	3 days
International equities	265.1	Monthly	14-30 days
Fixed income	244.9	Monthly	3 days
Total	$ 1,032.3		

Our Pension and Other Postretirement Benefit Plans' Funded Status and Related Disclosure. The following table provides a reconciliation of the plans' funded status and amounts reflected in our Consolidated Balance Sheets at December 31 based on a December 31 measurement date:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2018**	2017	**2018**	2017
Change in projected benefit obligation[1]				
Benefit obligation at beginning of year	**$ 2,192.6**	$ 2,165.8	**$ 556.3**	$ 529.0
Service cost	**31.3**	30.0	**5.0**	4.8
Interest cost	**67.1**	68.3	**17.6**	17.8
Plan participants' contributions	**—**	—	**5.7**	5.7
Plan amendments	**0.2**	0.9	**0.1**	1.6
Actuarial (gain) loss	**(103.9)**	98.3	**(51.7)**	36.2
Settlement loss	**0.8**	1.6	**—**	—
Benefits paid	**(206.8)**	(172.3)	**(41.1)**	(39.3)
Estimated benefits paid by incurred subsidy	**—**	—	**0.6**	0.5
Projected benefit obligation at end of year	**$ 1,981.3**	$ 2,192.6	**$ 492.5**	$ 556.3
Change in plan assets				
Fair value of plan assets at beginning of year	**$ 2,160.0**	$ 1,750.9	**$ 262.5**	$ 231.4
Actual (loss) return on plan assets	**(88.4)**	299.1	**(31.8)**	33.1
Employer contributions	**2.9**	282.3	**21.0**	31.6
Plan participants' contributions	**—**	—	**5.7**	5.7
Benefits paid	**(206.8)**	(172.3)	**(41.1)**	(39.3)
Fair value of plan assets at end of year	**$ 1,867.7**	$ 2,160.0	**$ 216.3**	$ 262.5
Funded Status at end of year	**$ (113.6)**	$ (32.6)	**$ (276.2)**	$ (293.8)
Amounts recognized in the statement of financial position consist of:				
Noncurrent assets	**—**	9.8	**—**	—
Current liabilities	**(3.0)**	(2.8)	**(0.8)**	(0.7)
Noncurrent liabilities	**(110.6)**	(39.6)	**(275.4)**	(293.1)
Net amount recognized at end of year[2]	**$ (113.6)**	$ (32.6)	**$ (276.2)**	$ (293.8)
Amounts recognized in accumulated other comprehensive income or regulatory asset/liability[3]				
Unrecognized prior service credit	**$ 3.2**	$ 2.5	**$ (19.0)**	$ (23.1)
Unrecognized actuarial loss	**761.2**	692.9	**75.3**	84.2
Net amount recognized at end of year	**$ 764.4**	$ 695.4	**$ 56.3**	$ 61.1

[1] The change in benefit obligation for Pension Benefits represents the change in Projected Benefit Obligation while the change in benefit obligation for Other Postretirement Benefits represents the change in accumulated postretirement benefit obligation.
[2] We recognize our Consolidated Balance Sheets underfunded and overfunded status of our various defined benefit postretirement plans, measured as the difference between the fair value of the plan assets and the benefit obligation.
[3] We determined that for certain rate-regulated subsidiaries the future recovery of pension and other postretirement benefits costs is probable. These rate-regulated subsidiaries recorded regulatory assets and liabilities of $798.3 million and $0.1 million, respectively, as of December 31, 2018, and $733.5 million and $0.1 million, respectively, as of December 31, 2017 that would otherwise have been recorded to accumulated other comprehensive loss.

Our accumulated benefit obligation for our pension plans was $1,965.6 million and $2,170.4 million as of December 31, 2018 and 2017, respectively. The accumulated benefit obligation as of a date is the actuarial present value of benefits attributed by the pension benefit formula to employee service rendered prior to that date and based on current and past compensation levels. The accumulated benefit obligation differs from the projected benefit obligation disclosed in the table above in that it includes no assumptions about future compensation levels.

Our pension plans were underfunded by $113.6 million at December 31, 2018 compared to being underfunded, in aggregate, by $32.6 million at December 31, 2017. The decline in the funded status was due primarily to unfavorable asset returns offset by an increase in discount rates. We contributed $2.9 million and $282.3 million to our pension plans in 2018 and 2017, respectively.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

Our other postretirement benefit plans were underfunded by $276.2 million at December 31, 2018 compared to being underfunded by $293.8 million at December 31, 2017. The improvement in funded status was primarily due to employer contributions and an increase in discount rates, offset by unfavorable asset returns. We contributed $21.0 million and $31.6 million to our other postretirement benefit plans in 2018 and 2017, respectively.

No amounts of our pension or other postretirement benefit plans' assets are expected to be returned to us or any of our subsidiaries in 2018.

In 2018 and 2017, some of our qualified pension plans paid lump sum payouts in excess of the respective plan's service cost plus interest cost, thereby meeting the requirement for settlement accounting. We recorded settlement charges of $18.5 million and $13.7 million in 2018 and 2017, respectively. Net periodic pension benefit cost for 2018 was increased by $3.0 million as a result of the interim remeasurement.

The following table provides the key assumptions that were used to calculate the pension and other postretirement benefits obligations for our various plans as of December 31:

	Pension Benefits		**Other Postretirement Benefits**	
	2018	2017	**2018**	2017
Weighted-average assumptions to Determine Benefit Obligation				
Discount Rate	**4.26%**	3.58%	**4.31%**	3.67%
Rate of Compensation Increases	**4.00%**	4.00%	**—**	—
Health Care Trend Rates				
Trend for Next Year	**—**	—	**8.48%**	8.52%
Ultimate Trend	**—**	—	**4.50%**	4.50%
Year Ultimate Trend Reached	**—**	—	**2026**	2025

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

(in millions)	1% point increase	1% point decrease
Effect on service and interest components of net periodic cost	$ 1.3	$ (1.1)
Effect on accumulated postretirement benefit obligation	25.0	(22.0)

We expect to make contributions of approximately $3.0 million to our pension plans and approximately $20.6 million to our postretirement medical and life plans in 2018.

The following table provides benefits expected to be paid in each of the next five fiscal years, and in the aggregate for the five fiscal years thereafter. The expected benefits are estimated based on the same assumptions used to measure our benefit obligation at the end of the year and include benefits attributable to the estimated future service of employees:

(in millions)	Pension Benefits	Other Postretirement Benefits	Federal Subsidy Receipts
Year(s)			
2019	$ 177.4	$ 34.3	$ 0.5
2020	176.0	35.0	0.5
2021	176.5	35.7	0.5
2022	174.4	36.0	0.4
2023	166.5	35.8	0.4
2024-2028	748.7	171.8	1.7

The following table provides the components of the plans' actuarially determined net periodic benefits cost for each of the three years ended December 31, 2018, 2017 and 2016:

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2018**	2017	2016	**2018**	2017	2016
Components of Net Periodic Benefit Cost[(1)]						
Service cost	**$ 31.3**	$ 30.0	$ 30.7	**$ 5.0**	$ 4.8	$ 5.0
Interest cost	**67.1**	68.3	89.7	**17.6**	17.8	22.0
Expected return on assets	**(142.3)**	(123.1)	(132.9)	**(14.9)**	(15.9)	(17.2)
Amortization of prior service cost (credit)	**(0.4)**	(0.7)	(0.2)	**(4.0)**	(4.4)	(4.9)
Recognized actuarial loss	**40.6**	52.9	61.2	**3.8**	3.0	3.1
Settlement loss	**18.5**	13.7	—	**—**	—	—
Total Net Periodic Benefits Cost	**$ 14.8**	$ 41.1	$ 48.5	**$ 7.5**	$ 5.3	$ 8.0

[(1)]Service cost is presented in "Operation and maintenance" on the Statements of Consolidated Income (Loss). Non-service cost components are presented within "Other, net."

The following table provides the key assumptions that were used to calculate the net periodic benefits cost for our various plans:

	Pension Benefits			Other Postretirement Benefits		
	2018	2017	2016	**2018**	2017	2016
Weighted-average Assumptions to Determine Net Periodic Benefit Cost						
Discount rate - service cost[(1)]	**3.79%**	4.40%	4.24%	**3.89%**	4.58%	4.33%
Discount rate - interest cost[(1)]	**3.15%**	3.31%	4.24%	**3.27%**	3.48%	4.33%
Expected Long-Term Rate of Return on Plan Assets	**7.00%**	7.25%	8.00%	**5.80%**	6.99%	7.85%
Rate of Compensation Increases	**4.00%**	4.00%	4.00%	**—**	—	—

[(1)] In January 2017, we changed the method used to estimate the service and interest components of net periodic benefit cost for pension and other postretirement benefits. This change, compared to the previous method, resulted in a decrease in the actuarially-determined service and interest cost components. Historically, we estimated service and interest cost utilizing a single weighted-average discount rate derived from the yield curve used to measure the benefit obligation at the beginning of the period. For fiscal 2017 and beyond, we now utilize a full yield curve approach to estimate these components by applying the specific spot rates along the yield curve used in the determination of the benefit obligation to the relevant projected cash flows.

We believe it is appropriate to assume a 7.00% and 5.80% rate of return on pension and other postretirement plan assets, respectively, for our calculation of 2018 pension benefits cost. These rates are primarily based on asset mix and historical rates of return and were adjusted in the current year due to anticipated changes in asset allocation and projected market returns.

The following table provides other changes in plan assets and projected benefit obligations recognized in other comprehensive income or regulatory asset or liability:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2018**	2017	**2018**	2017
Other Changes in Plan Assets and Projected Benefit Obligations Recognized in Other Comprehensive Income or Regulatory Asset or Liability				
Net prior service cost	**$ 0.2**	$ 0.9	**$ 0.1**	$ 1.6
Net actuarial loss (gain)	**127.5**	(76.1)	**(5.0)**	18.9
Settlements	**(18.5)**	(13.7)	**—**	—
Less: amortization of prior service cost	**0.4**	0.7	**4.0**	4.4
Less: amortization of net actuarial loss	**(40.6)**	(52.9)	**(3.8)**	(3.0)
Total Recognized in Other Comprehensive Income or Regulatory Asset or Liability	**$ 69.0**	$ (141.1)	**$ (4.7)**	$ 21.9
Amount Recognized in Net Periodic Benefits Cost and Other Comprehensive Income or Regulatory Asset or Liability	**$ 83.8**	$ (100.0)	**$ 2.8**	$ 27.2

Based on a December 31 measurement date, the net unrecognized actuarial loss, unrecognized prior service cost (credit), and unrecognized transition obligation that will be amortized into net periodic benefit cost during 2019 for the pension plans are $45.5 million, $0.2 million and zero, respectively, and for other postretirement benefit plans are $2.4 million, $(3.2) million and zero, respectively.

12. Equity

We raise equity financing through a variety of programs including traditional common equity issuances, ATM issuances and preferred stock issuances. As of December 31, 2018, we had 400,000,000 shares of common stock and 20,000,000 shares of preferred stock authorized for issuance, of which 372,363,656 shares of common stock and 420,000 shares of preferred stock are currently outstanding.

Holders of shares of our common stock are entitled to receive dividends when, as and if declared by the Board out of funds legally available. The policy of the Board has been to declare cash dividends on a quarterly basis payable on or about the 20th day of February, May, August and November. We have paid quarterly common dividends totaling $0.78, $0.70 and $0.64 per share for the years ended December 31, 2018, 2017 and 2016, respectively. Our Board declared a quarterly common dividend of $0.20 per share, payable on February 20, 2019 to holders of record on February 11, 2019. We have certain debt covenants which could potentially limit the amount of dividends the Company could pay in order to maintain compliance with these covenants. Refer to Note 14, "Long-Term Debt," for more information. As of December 31, 2018, these covenants did not restrict the amount of dividends that were available to be paid.

Dividends paid to preferred shareholders vary based on the series of preferred stock owned. Additional information is provided below. Holders of our shares of common stock are subject to the prior dividend rights of holders of our preferred stock or the depositary shares representing such preferred stock outstanding, and if full dividends have not been declared and paid on all outstanding shares of preferred stock in any dividend period, no dividend may be declared or paid or set aside for payment on our common stock.

Common and preferred stock activity for 2018 and 2017 is described further below:

ATM Program and Forward Sale Agreements. On May 3, 2017, we entered into four separate equity distribution agreements, pursuant to which we were able to sell up to an aggregate of $500.0 million of our common stock.

On November 13, 2017, under the ATM program, we executed a forward agreement, which allowed us to issue a fixed number of shares at a price to be settled in the future. On November 6, 2018 the forward agreement was settled for $26.43 per share, resulting in $167.7 million of net proceeds. The equity distribution agreements entered into on May 3, 2017 expired December 31, 2018.

On November 1, 2018, we entered into five separate equity distribution agreements, pursuant to which we may sell, from time to time, up to an aggregate of $500.0 million of our common stock.

On December 6, 2018, under the ATM program described immediately above, we executed a forward agreement which allows us to issue a fixed number of shares at a price to be settled in the future. From December 6, 2018 to December 10, 2018, 4,708,098 shares were borrowed from third parties and sold by the dealer at a weighted average price of $26.55 per share. We may settle this agreement in shares, cash, or net shares by December 6, 2019. Had we settled all the shares under the forward agreement at December 31, 2018, we would have received approximately $124.8 million, based on a net price of $26.51 per share.

As of December 31, 2018, the ATM program (including the impacts of the aforementioned forward sales agreement) had approximately $309.4 million of equity available for issuance. The program expires on December 31, 2020.

The following table summarizes our activity under the ATM program:

Year Ending December 31,		**2018**		2017		2016
Number of shares issued		**8,883,014**		11,931,376		—
Average price per share	**$**	**26.85**	$	26.58	$	—
Proceeds, net of fees (*in millions)*	**$**	**232.5**	$	314.7	$	—

Private Placement of Common Stock. On May 4, 2018, we completed the sale of 24,964,163 shares of $0.01 par value common stock at a price of $24.28 per share in a private placement to selected institutional and accredited investors. The private placement resulted in $606.0 million of gross proceeds or $599.6 million of net proceeds, after deducting commissions and sale expenses. The common stock issued in connection with the private placement was registered on Form S-1, filed with the SEC on May 11, 2018.

Preferred Stock. On June 11, 2018, we completed the sale of 400,000 shares of 5.650% Series A Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock (the "Series A Preferred Stock") at a price of $1,000 per share. The transaction resulted in $400.0 million of gross proceeds or $393.9 million of net proceeds, after deducting commissions and sale expenses. The Series A Preferred Stock was issued in a private placement pursuant to SEC Rule 144A. On December 13, 2018, we filed a registration statement with the SEC enabling holders to exchange their unregistered shares of Series A Preferred Stock for publicly registered shares with substantially identical terms.

Proceeds from the issuance of the Series A Preferred Stock were used to pay a portion of the notes tendered in June 2018 and the redemption of the remaining notes in July 2018. See Note 14, “Long-term Debt” for additional information regarding the tender offer and redemption.

Dividends on the Series A Preferred Stock accrue and are cumulative from the date the shares of Series A Preferred Stock were originally issued to, but not including, June 15, 2023 at a rate of 5.650% per annum of the $1,000 liquidation preference per share. On and after June 15, 2023, dividends on the Series A Preferred Stock will accumulate for each five year period at a percentage of the $1,000 liquidation preference equal to the five-year U.S. Treasury Rate plus (i) in respect of each five year period commencing on or after June 15, 2023 but before June 15, 2043, a spread of 2.843% (the “Initial Margin”), and (ii) in respect of each five year period commencing on or after June 15, 2043, the Initial Margin plus 1.000%. The Series A Preferred Stock may be redeemed by us at our option on June 15, 2023, or on each date falling on the fifth anniversary thereafter, or in connection with a ratings event (as defined in the Certificate of Designation of the Series A Preferred Stock).

Holders of Series A Preferred Stock generally have no voting rights, except for limited voting rights with respect to (i) potential amendments to our certificate of incorporation that would have a material adverse effect on the existing preferences, rights, powers or duties of the Series A Preferred Stock, (ii) the creation or issuance of any security ranking on a parity with the Series A Preferred

Stock if the cumulative dividends payable on then outstanding Series A Preferred Stock are in arrears, or (iii) the creation or issuance of any security ranking senior to the Series A Preferred Stock. The Series A Preferred Stock does not have a stated maturity and is not subject to mandatory redemption or any sinking fund. The Series A Preferred Stock will remain outstanding indefinitely unless repurchased or redeemed by us. Any such redemption would be effected only out of funds legally available for such purposes and will be subject to compliance with the provisions of our outstanding indebtedness.

On December 5, 2018, we completed the sale of 20,000,000 depositary shares with an aggregate liquidation preference of $500,000,000 under the Company's registration statement on Form S-3. Each depositary share represents 1/1,000th ownership interest in a share of our 6.500% Series B Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock, liquidation preference $25,000 per share (equivalent to $25 per depositary share) (the "Series B Preferred Stock). The transaction resulted in $500.0 million of gross proceeds or $486.1 million of net proceeds, after deducting commissions and sale expenses.

Dividends on the Series B Preferred Stock accrue and are cumulative from the date the shares of Series B Preferred Stock were originally issued to, but not including, March 15, 2024 at a rate of 6.500% per annum of the $25,000 liquidation preference per share. On and after March 15, 2024, dividends on the Series B Preferred Stock will accumulate for each five year period at a percentage of the $25,000 liquidation preference equal to the five-year U.S. Treasury Rate plus (i) in respect of each five year period commencing on or after March 15, 2024 but before March 15, 2044, a spread of 3.632% (the "Initial Margin"), and (ii) in respect of each five year period commencing on or after March 15, 2044, the Initial Margin plus 1.000%. The Series B Preferred Stock may be redeemed by us at our option on March 15, 2024, or on each date falling on the fifth anniversary thereafter, or in connection with a ratings event (as defined in the Certificate of Designation of the Series B Preferred Stock).

On December 27, 2018, we issued 20,000 shares of "Series B-1 Preferred Stock", par value $0.01 per share, liquidation preference $0.01 per share ("Series B-1 Preferred Stock"), as a distribution with respect to the Series B Preferred Stock. As a result, each of the depositary shares issued on December 5, 2018 now represents a 1/1,000th ownership interest in a share of Series B Preferred Stock and a 1/1,000th ownership interest in a share of Series B-1 Preferred Stock. The Company issued the Series B-1 Preferred Stock to enhance the voting rights of the Series B Preferred Stock to comply with the minimum voting rights policy of the New York Stock Exchange. The Series B-1 Preferred Stock is paired with the Series B Preferred Stock and may not be transferred, redeemed or repurchased except in connection with the simultaneous transfer, redemption or repurchase of a like number of shares of the underlying Series B Preferred Stock.

Holders of Series B Preferred Stock generally have no voting rights, except for limited voting rights with respect to (i) potential amendments to our certificate of incorporation that would have a material adverse effect on the existing preferences, rights, powers or duties of the Series B Preferred Stock, (ii) the creation or issuance of any security ranking on a parity with the Series B Preferred Stock if the cumulative dividends payable on then outstanding Series B Preferred Stock are in arrears, or (iii) the creation or issuance of any security ranking senior to the Series B Preferred Stock. In addition, if and whenever dividends on any shares of Series B Preferred Stock shall not have been declared and paid for at least six dividend periods, whether or not consecutive, the number of directors then constituting our Board of Directors shall automatically be increased by two until all accumulated and unpaid dividends on the Series B Preferred Stock shall have been paid in full, and the holders of Series B-1 Preferred Stock, voting as a class together with the holders of any outstanding securities ranking on a parity with the Series B-1 Preferred Stock and having like voting rights that are exercisable at the time and entitled to vote thereon, shall be entitled to elect the two additional directors. The Series B Preferred Stock does not have a stated maturity and is not subject to mandatory redemption or any sinking fund. The Series B Preferred Stock will remain outstanding indefinitely unless repurchased or redeemed by us. Any such redemption would be effected only out of funds legally available for such purposes and will be subject to compliance with the provisions of our outstanding indebtedness.

13. Share-Based Compensation

Our stockholders most recently approved the NiSource Inc. 2010 Omnibus Incentive Plan ("Omnibus Plan") at the Annual Meeting of Stockholders held on May 12, 2015. The Omnibus Plan provides for awards to employees and non-employee directors of incentive and nonqualified stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, cash-based awards and other stock-based awards and supersedes the long-term incentive plan approved by stockholders on April 13, 1994 ("1994 Plan") and the Director Stock Incentive Plan ("Director Plan"). The Omnibus Plan provides that the number of shares of common stock of NiSource available for awards is 8,000,000 plus the number of shares subject to outstanding awards that expire or terminate for any reason that were granted under either the 1994 Plan or the Director Plan, plus the number of shares that were awarded as a result of the Separation-related adjustments (discussed below). At December 31, 2018, there were 3,793,557 shares reserved for future awards under the Omnibus Plan.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

We recognized stock-based employee compensation expense of $15.2 million, $15.3 million and $15.1 million, during 2018, 2017 and 2016, respectively, as well as related tax benefits of $3.7 million, $5.9 million and $5.8 million, respectively. Additionally, we adopted ASU 2016-09 in the third quarter of 2016. We recognized related excess tax benefits from the distribution of vested share-based employee compensation of $1.0 million, $4.4 million and $7.2 million in 2018, 2017 and 2016, respectively.

As of December 31, 2018, the total remaining unrecognized compensation cost related to non-vested awards amounted to $16.6 million, which will be amortized over the weighted-average remaining requisite service period of 1.7 years.

Restricted Stock Units and Restricted Stock. In 2018, we granted 158,689 restricted stock units and shares of restricted stock to employees, subject to service conditions. The total grant date fair value of the restricted stock units and shares of restricted stock was $3.5 million, based on the average market price of our common stock at the date of each grant less the present value of any dividends not received during the vesting period, which will be expensed over the vesting period which is generally three years. As of December 31, 2018, 154,799 non-vested restricted stock units and shares of restricted stock granted in 2018 were outstanding as of December 31, 2018.

Restricted stock units and shares of restricted stock granted to employees in 2017 and 2016 were immaterial.

If an employee terminates employment before the service conditions lapse under the 2016, 2017 or 2018 awards due to (1) Retirement or Disability (as defined in the award agreement), or (2) death, the service conditions will lapse on the date of such termination with respect to a pro rata portion of the restricted stock units and shares of restricted stock based upon the percentage of the service period satisfied between the grant date and the date of the termination of employment. In the event of a change in control (as defined in the award agreement), all unvested shares of restricted stock and restricted stock units awarded will immediately vest upon termination of employment occurring in connection with a change in control. Termination due to any other reason will result in all unvested shares of restricted stock and restricted stock units awarded being forfeited effective on the employee’s date of termination.

(shares)	Restricted Stock Units	Weighted Average Award Date Fair Value Per Unit ($)
Non-vested at December 31, 2017	698,126	15.09
Granted	158,689	21.94
Forfeited	(6,890)	21.42
Vested	(671,247)	14.91
Non-vested at December 31, 2018	**178,678**	**21.82**

Performance Shares. In 2018, we awarded 514,338 performance shares subject to service, performance and market conditions. The service conditions for these awards lapse on February 26, 2021. The performance period for the awards is the period beginning January 1, 2018 and ending December 31, 2020. The performance conditions are based on the achievement of one non-GAAP financial measure and additional operational measures as outlined below.

The financial measure is cumulative net operating earnings per share ("NOEPS"), which we define as income from continuing operations adjusted for certain unusual or non-recurring items. The number of cumulative NOEPS shares determined using this measure shall be increased or decreased based on our relative total shareholder return, a market condition which we define as the annualized growth in dividends and share price of a share of our common stock (calculated using a 20 trading day average of our closing price beginning on December 31, 2017 and ending on December 31, 2020) compared to the total shareholder return of a predetermined peer group of companies. A relative shareholder return result within the first quartile will result in an increase to the NOEPS shares of 25% while a relative shareholder return result within the fourth quartile will result in a decrease of 25%. A Monte Carlo analysis was used to value the portion of these awards dependent on market conditions. The grant date fair value of the awards was $9.2 million, based on the average market price of NiSource’s common stock at the date of each grant less the present value of dividends not received during the vesting period which will be expensed over the three year requisite service period. As of December 31, 2018, 405,255 of these non-vested performance shares granted in 2018 remained outstanding.

If a threshold level of cumulative NOEPS financial performance is achieved, additional operational measures which we refer to as the customer value index, which consists of five equally weighted areas of focus including safety, customer satisfaction, financial, culture and environmental apply. Each area of focus represents 20% of the customer value index shares and the targets for all areas must be met for these awards to be eligible for 100% payout of these awards. Individual payout percentages for these shares may range from 0%-200% as determined by the compensation committee in its sole discretion. Due to this discretion, these shares are not considered to be granted under ASC 718. The service inception date fair value of the awards was $2.4 million, based on the closing market price of our common stock on the service inception date of each award. This value will be reassessed at each reporting period to be based on our closing market price of our common stock at the reporting period date with adjustments to expense recorded as appropriate. As of December 31, 2018, 93,522 of these awards that were issued in 2018 remained outstanding. The service conditions for these awards lapse on February 28, 2021.

In 2017, we granted 660,750 performance shares subject to service, performance and market conditions. The grant date fair value of the awards was $12.9 million, based on the average market price of our common stock at the date of each grant less the present value of dividends not received during the vesting period which will be expensed over the three year requisite service period. The performance conditions are based on achievement of non-GAAP financial measures similar to those discussed above: cumulative net operating earnings per share for the three-year period ending December 31, 2019 and relative total shareholder return (calculated using a 20 trading day average of our closing price beginning on December 31, 2016 and ending on December 31, 2019). As of December 31, 2018, 579,292 non-vested performance shares granted in 2017 remained outstanding. The service conditions for these awards lapse on February 28, 2020.

In 2016, we granted 647,305 performance shares subject to service, performance and market conditions. The grant date fair value of the awards was $12.6 million, based on the average market price of our common stock at the date of each grant less the present value of dividends not received during the vesting period which will be expensed over the three year requisite service period. Similar to the above grants, performance conditions for these awards are based on achievement of certain non-GAAP financial measures: cumulative net operating earnings per share for the three-year period ending December 31, 2018 and relative total shareholder return (calculated using a 20 trading day average of our closing price beginning on December 31, 2015 and ending on December 31, 2018). As of December 31, 2018, 556,649 non-vested performance shares granted in 2016 remained outstanding. The service conditions for these awards lapse on February 28, 2019.

(shares)	Performance Awards	Weighted Average Grant Date Fair Value Per Unit ($)[1]
Non-vested at December 31, 2017	1,184,773	19.52
Granted	514,338	22.51
Forfeited	(64,393)	26.79
Vested	—	—
Non-vested at December 31, 2018	**1,634,718**	**20.45**

[1]2018 performance shares awarded based on the customer value index are included at reporting date fair value as these awards have not been granted under ASC 718 as discussed above.

Non-employee Director Awards. As of May 11, 2010, awards to non-employee directors may be made only under the Omnibus Plan. Currently, restricted stock units are granted annually to non-employee directors, subject to a non-employee director's election to defer receipt of such restricted stock unit award. The non-employee director's annual award of restricted stock units vest on the first anniversary of the grant date subject to special pro-rata vesting rules in the event of retirement or disability (as defined in the award agreement), or death. The vested restricted stock units are payable as soon as practicable following vesting except as otherwise provided pursuant to the non-employee director's election to defer. Certain restricted stock units remain outstanding from the Director Plan. All such awards are fully vested and shall be distributed to the directors upon their separation from the Board.

As of December 31, 2018, 142,414 restricted stock units are outstanding to non-employee directors under either the Omnibus Plan or the Director Plan. Of this amount, 53,422 restricted stock units are unvested and expected to vest.

401(k) Match, Profit Sharing and Company Contribution. We have a voluntary 401(k) savings plan covering eligible employees that allows for periodic discretionary matches as a percentage of each participant's contributions payable in cash for nonunion employees and generally payable in shares of NiSource common stock for union employees, subject to collective bargaining. We also have a retirement savings plan that provides for discretionary profit sharing contributions similarly payable in cash or shares of NiSource common stock to eligible employees based on earnings results; and eligible employees hired after January 1, 2010 receive a non-elective company contribution of 3% of eligible pay similarly payable in cash or shares of NiSource common stock.

For the years ended December 31, 2018, 2017 and 2016, we recognized 401(k) match, profit sharing and non-elective contribution expense of $37.6 million, $37.6 million and $32.3 million, respectively.

14. Long-Term Debt

Our long-term debt as of December 31, 2018 and 2017 is as follows:

Long-term debt type	Maturity as of December 31, 2018	Weighted average interest rate (%)	Outstanding balance as of December 31, *(in millions)* 2018	2017
Senior notes:				
NiSource	March 2018	6.40%	**—**	275.1
NiSource	January 2019	6.80%	**—**	255.1
NiSource	September 2020	5.45%	**—**	325.1
NiSource	December 2021	4.45%	**63.6**	63.6
NiSource	March 2022	6.13%	**—**	180.0
NiSource	November 2022	2.65%	**500.0**	500.0
NiSource	February 2023	3.85%	**250.0**	250.0
NiSource	June 2023	3.65%	**350.0**	—
NiSource	November 2025	5.89%	**265.0**	265.0
NiSource	May 2027	3.49%	**1,000.0**	1,000.0
NiSource	December 2027	6.78%	**3.0**	3.0
NiSource	December 2040	6.25%	**250.0**	250.0
NiSource	June 2041	5.95%	**400.0**	400.0
NiSource	February 2042	5.80%	**250.0**	250.0
NiSource	February 2043	5.25%	**500.0**	500.0
NiSource	February 2044	4.80%	**750.0**	750.0
NiSource	February 2045	5.65%	**500.0**	500.0
NiSource	May 2047	4.38%	**1,000.0**	1,000.0
NiSource	March 2048	3.95%	**750.0**	750.0
Total senior notes			**$ 6,831.6**	$ 7,516.9
Medium term notes:				
NiSource	April 2022 to May 2027	7.99%	**$ 49.0**	$ 49.0
NIPSCO	August 2022 to August 2027	7.61%	**68.0**	68.0
Columbia of Massachusetts	December 2025 to February 2028	6.30%	**40.0**	40.0
Total medium term notes			**$ 157.0**	$ 157.0
Capital leases:				
NIPSCO	May 2018	3.95%	**$ —**	$ 3.8
NiSource Corporate Services	January 2019 to October 2022	3.68%	**11.6**	1.4
Columbia of Ohio	October 2021 to June 2038	6.33%	**91.5**	88.5
Columbia of Virginia	July 2029 to December 2037	7.12%	**15.2**	5.2
Columbia of Kentucky	May 2027	3.79%	**0.3**	0.4
Columbia of Pennsylvania	August 2027 to June 2036	5.42%	**30.0**	31.0
Columbia of Massachusetts	December 2033 to November 2043	5.48%	**45.7**	22.8
Total capital leases			**194.3**	153.1
Pollution control bonds - NIPSCO	April 2019	5.85%	**41.0**	41.0
Unamortized issuance costs and discounts			**(68.5)**	$ (71.5)
Total Long-Term Debt			**$ 7,155.4**	$ 7,796.5

Details of our 2018 long-term debt related activity are summarized below:

- On March 15, 2018, we redeemed $275.1 million of 6.40% senior unsecured notes at maturity.
- In June 2018, we executed a tender offer for $209.0 million of outstanding notes consisting of a combination of our 6.80% notes due 2019, 5.45% notes due 2020, and 6.125% notes due 2022. In conjunction with the debt retired, we recorded a $12.5 million loss on early extinguishment of long-term debt, primarily attributable to early redemption premiums.
- On June 11, 2018, we closed our private placement of $350.0 million of 3.65% senior unsecured notes maturing in 2023 which resulted in approximately $346.6 million of net proceeds after deducting commissions and expenses. We used the net proceeds from this private placement to pay a portion of the redemption price for the notes subject to the tender offer described above.
- In July 2018, we redeemed $551.1 million of outstanding notes representing the remainder of our 6.80% notes due 2019, 5.45% notes due 2020 and 6.125% notes due 2022. During the third quarter of 2018, we recorded a $33.0 million loss on early extinguishment of long-term debt, primarily attributable to early redemption premiums.

Details of our 2017 long-term debt related activity are summarized below:

- On March 27, 2017, we redeemed $30.0 million of 7.86% and $2.0 million of 7.85% medium-term notes at maturity.
- On April 3, 2017, we redeemed $12.0 million of 7.82%, $10.0 million of 7.92%, $2.0 million of 7.93% and $1.0 million of 7.94% medium-term notes at maturity.
- On May 22, 2017, we closed our placement of $2.0 billion in aggregate principal amount of our senior notes, comprised of $1.0 billion of 3.49% senior notes due 2027 and $1.0 billion of 4.375% senior notes due 2047. Related to this placement, we settled $950.0 million of aggregate notional value forward-starting interest rate swaps, originally entered into to mitigate interest risk associated with the planned issuance of these notes. Refer to Note 9, "Risk Management Activities," for additional information.
- During the second quarter of 2017, we executed a tender offer for $990.7 million of outstanding notes consisting of a combination of our 6.40% notes due 2018, 6.80% notes due 2019, 5.45% notes due 2020, and 6.125% notes due 2022. In conjunction with the debt retired, we recorded a $111.5 million loss on early extinguishment of long-term debt, primarily attributable to early redemption premiums.
- On June 12, 2017, NIPSCO redeemed $22.5 million of 7.59% medium-term notes at maturity.
- On July 1, 2017, NIPSCO redeemed $55.0 million of 5.70% pollution control bonds at maturity.
- On August 4, 2017, NIPSCO redeemed $5.0 million of 7.02% medium-term notes at maturity.
- On September 14, 2017, we closed our placement of $750.0 million of 3.95% senior notes due 2048. Related to this placement, we settled $750.0 million of aggregate notional value treasury lock agreements, originally entered into to mitigate the interest risk associated with the planned issuance of these notes. Refer to Note 9, "Risk Management Activities," for additional information.
- On September 15, 2017, we redeemed $210.4 million of 5.25% senior unsecured notes at maturity.
- On November 17, 2017, we closed our placement of $500.0 million of 2.65% senior notes due 2022 to repay a $500.0 million variable-rate term loan due March 29, 2019. Related to this placement, we settled $250.0 million of aggregate notional value treasury lock agreements originally entered into to mitigate the interest risk associated with the planned issuance of these notes. Refer to Note 9, “Risk Management Activities,” for additional information.

See Note 18-A, "Contractual Obligations," for the outstanding long-term debt maturities at December 31, 2018.

Unamortized debt expense, premium and discount on long-term debt applicable to outstanding bonds are being amortized over the life of such bonds.

We are subject to a financial covenant under our revolving credit facility which requires us to maintain a debt to capitalization ratio that does not exceed 70%. A similar covenant in a 2005 private placement note purchase agreement requires us to maintain a debt to capitalization ratio that does not exceed 75%. As of December 31, 2018, the ratio was 61.4%.

We are also subject to certain other non-financial covenants under the revolving credit facility. Such covenants include a limitation on the creation or existence of new liens on our assets, generally exempting liens on utility assets, purchase money security interests, preexisting security interests and an additional subset of assets equal to $150 million. An asset sale covenant generally restricts the sale, conveyance, lease, transfer or other disposition of our assets to those dispositions that are for a price not materially less than fair market of such assets, that would not materially impair our ability to perform obligations under the revolving credit facility, and that together with all other such dispositions, would not have a material adverse effect. The covenant also restricts dispositions to no more than 10% of our consolidated total assets on December 31, 2015. The revolving credit facility also includes a cross-default provision, which triggers an event of default under the credit facility in the event of an uncured payment default relating to any indebtedness of us or any of our subsidiaries in a principal amount of $50.0 million or more.

Our indentures generally do not contain any financial maintenance covenants. However, our indentures are generally subject to cross-default provisions ranging from uncured payment defaults of $5 million to $50 million, and limitations on the incurrence of liens on our assets, generally exempting liens on utility assets, purchase money security interests, preexisting security interests and an additional subset of assets capped at 10% of our consolidated net tangible assets.

15. Short-Term Borrowings

We generate short-term borrowings from our revolving credit facility, commercial paper program, letter of credit issuances, accounts receivable transfer programs and term loan borrowings. Each of these borrowing sources is described further below.

We maintain a revolving credit facility to fund ongoing working capital requirements, including the provision of liquidity support for our commercial paper program, provide for issuance of letters of credit and also for general corporate purposes. Our revolving credit facility has a program limit of $1.85 billion and is comprised of a syndicate of banks led by Barclays. At December 31, 2018 and 2017, we had no outstanding borrowings under this facility.

Our commercial paper program has a program limit of up to $1.5 billion with a dealer group comprised of Barclays, Citigroup, Credit Suisse and Wells Fargo. At December 31, 2018 and 2017, we had $978.0 million and $869.0 million, respectively, of commercial paper outstanding.

As of December 31, 2018 and 2017, we had issued $10.2 million and $11.1 million of stand-by letters of credit, respectively. All stand-by letters of credit were under the revolving credit facility.

Transfers of accounts receivable are accounted for as secured borrowings resulting in the recognition of short-term borrowings on the Consolidated Balance Sheets in the amount of $399.2 million and $336.7 million as of December 31, 2018 and 2017, respectively. Refer to Note 17, "Transfers of Financial Assets," for additional information.

On April 18, 2018, we entered into a multiple-draw $600.0 million term loan agreement with a syndicate of banks led by MUFG Bank, Ltd. The term loan matures April 17, 2019, at which point any and all outstanding borrowings under the agreement are due. Interest charged on borrowings depends on the variable rate structure we elected at the time of each borrowing. Under the agreement, we borrowed an initial tranche of $150.0 million on April 18, 2018 with an interest rate of LIBOR plus 50 basis points and a second tranche of $450.0 million on May 31, 2018 with an interest rate of LIBOR plus 55 basis points.

Short-term borrowings were as follows:

At December 31, *(in millions)*		**2018**		2017
Commercial Paper weighted average interest rate of 2.96% and 1.97% at December 31, 2018 and 2017, respectively.	**$**	**978.0**	$	869.0
Accounts receivable securitization facility borrowings		**399.2**		336.7
Term loan weighted-average interest rate of 3.07% at December 31, 2018		**600.0**		—
Total Short-Term Borrowings	**$**	**1,977.2**	$	1,205.7

Other than for the term loan and certain commercial paper borrowings, cash flows related to the borrowings and repayments of the items listed above are presented net in the Statements of Consolidated Cash Flows as their maturities are less than 90 days.

16. Fair Value

A. Fair Value Measurements

Recurring Fair Value Measurements. The following tables present financial assets and liabilities measured and recorded at fair value on our Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2018 and December 31, 2017:

Recurring Fair Value Measurements December 31, 2018 (*in millions*)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2018
Assets				
Risk management assets	$ —	$ 24.0	$ —	$ 24.0
Available-for-sale securities	—	138.3	—	138.3
Total	**$ —**	**$ 162.3**	**$ —**	**$ 162.3**
Liabilities				
Risk management liabilities	$ —	$ 51.7	$ —	$ 51.7
Total	**$ —**	**$ 51.7**	**$ —**	**$ 51.7**

Recurring Fair Value Measurements December 31, 2017 (*in millions*)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2017
Assets				
Risk management assets	$ —	$ 21.1	$ —	$ 21.1
Available-for-sale securities	—	133.9	—	133.9
Total	**$ —**	**$ 155.0**	**$ —**	**$ 155.0**
Liabilities				
Risk management liabilities	$ —	$ 71.4	$ 0.3	$ 71.7
Total	**$ —**	**$ 71.4**	**$ 0.3**	**$ 71.7**

Risk management assets and liabilities include interest rate swaps, exchange-traded NYMEX futures and NYMEX options and non-exchange-based forward purchase contracts. When utilized, exchange-traded derivative contracts are based on unadjusted quoted prices in active markets and are classified within Level 1. These financial assets and liabilities are secured with cash on deposit with the exchange; therefore, nonperformance risk has not been incorporated into these valuations. Certain non-exchange-traded derivatives are valued using broker or over-the-counter, on-line exchanges. In such cases, these non-exchange-traded derivatives are classified within Level 2. Non-exchange-based derivative instruments include swaps, forwards, options and treasury lock agreements. In certain instances, these instruments may utilize models to measure fair value. We use a similar model to value similar instruments. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, other observable inputs for the asset or liability and market-corroborated inputs, (i.e., inputs derived principally from or corroborated by observable market data by correlation or other means). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized within Level 2. Certain derivatives trade in less active markets with a lower availability of pricing information and models may be utilized in the valuation. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized within Level 3. Credit risk is considered in the fair value calculation of derivative instruments that are not exchange-traded. Credit exposures are adjusted to reflect collateral agreements which reduce exposures. As of

December 31, 2018 and 2017, there were no material transfers between fair value hierarchies. Additionally, there were no changes in the method or significant assumptions used to estimate the fair value of our financial instruments.

We have entered into forward-starting interest rate swaps to hedge the interest rate risk on coupon payments of forecasted issuances of long-term debt. These derivatives are designated as cash flow hedges. Credit risk is considered in the fair value calculation of each agreement. As they are based on observable data and valuations of similar instruments, the hedges are categorized within Level 2 of the fair value hierarchy. There was no exchange of premium at the initial date of the swaps and we can settle the contracts at any time. For additional information, see Note 9, "Risk Management Activities."

NIPSCO has entered into long-term forward natural gas purchase instruments that range from five to ten years to lock in a fixed price for its natural gas customers. We value these contracts using a pricing model that incorporates market-based information when available, as these instruments trade less frequently and are classified within Level 2 of the fair value hierarchy. For additional information see Note 9, “Risk Management Activities.”

Available-for-sale securities are investments pledged as collateral for trust accounts related to our wholly-owned insurance company. Available-for-sale securities are included within “Other investments” in the Consolidated Balance Sheets. We value U.S. Treasury, corporate debt and mortgage-backed securities using a matrix pricing model that incorporates market-based information. These securities trade less frequently and are classified within Level 2. Total unrealized gains and losses from available-for-sale securities are included in other comprehensive income. The amortized cost, gross unrealized gains and losses and fair value of available-for-sale securities at December 31, 2018 and 2017 were:

December 31, 2018 *(in millions)*	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
Available-for-sale securities				
U.S. Treasury debt securities	$ 23.6	$ 0.1	$ (0.1)	$ 23.6
Corporate/Other debt securities	117.7	0.4	(3.4)	114.7
Total	**$ 141.3**	**$ 0.5**	**$ (3.5)**	**$ 138.3**

December 31, 2017 *(in millions)*	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
Available-for-sale securities				
U.S. Treasury debt securities	$ 26.9	$ —	$ (0.1)	$ 26.8
Corporate/Other debt securities	106.8	0.9	(0.6)	107.1
Total	**$ 133.7**	**$ 0.9**	**$ (0.7)**	**$ 133.9**

Realized gains and losses on available-for-sale securities were immaterial for the year-ended December 31, 2018 and 2017.

The cost of maturities sold is based upon specific identification. At December 31, 2018, approximately $2.9 million of U.S. Treasury debt securities and approximately $2.7 million of Corporate/Other debt securities have maturities of less than a year.

There are no material items in the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis for the years ended December 31, 2018 and 2017.

Non-recurring Fair Value Measurements. There were no significant non-recurring fair value measurements recorded during the twelve months ended December 31, 2018.

B. Other Fair Value Disclosures for Financial Instruments. The carrying amount of cash and cash equivalents, restricted cash, notes receivable, customer deposits and short-term borrowings is a reasonable estimate of fair value due to their liquid or short-term nature. Our long-term borrowings are recorded at historical amounts.

The following method and assumptions were used to estimate the fair value of each class of financial instruments.

Long-term debt. The fair value of outstanding long-term debt is estimated based on the quoted market prices for the same or similar securities. Certain premium costs associated with the early settlement of long-term debt are not taken into consideration in determining fair value. These fair value measurements are classified within Level 2 of the fair value hierarchy. For the years ended December 31, 2018 and 2017, there was no change in the method or significant assumptions used to estimate the fair value of long-term debt.

The carrying amount and estimated fair values of these financial instruments were as follows:

At December 31, *(in millions)*	**Carrying Amount 2018**	**Estimated Fair Value 2018**	Carrying Amount 2017	Estimated Fair Value 2017
Long-term debt (including current portion)	**$ 7,155.4**	**$ 7,228.3**	$ 7,796.5	$ 8,603.4

17. Transfers of Financial Assets

Columbia of Ohio, NIPSCO and Columbia of Pennsylvania each maintain a receivables agreement whereby they transfer their customer accounts receivables to third party financial institutions through wholly-owned and consolidated special purpose entities. The three agreements expire between March 2019 and October 2019 and may be further extended if mutually agreed to by the parties thereto.

All receivables transferred to third parties are valued at face value, which approximates fair value due to their short-term nature. The amount of the undivided percentage ownership interest in the accounts receivables transferred is determined in part by required loss reserves under the agreements.

Transfers of accounts receivable are accounted for as secured borrowings resulting in the recognition of short-term borrowings on the Consolidated Balance Sheets. As of December 31, 2018, the maximum amount of debt that could be recognized related to our accounts receivable programs is $455.0 million.

The following table reflects the gross receivables balance and net receivables transferred as well as short-term borrowings related to the securitization transactions as of December 31, 2018 and 2017:

At December 31, *(in millions)*	**2018**	2017
Gross Receivables	**$ 694.4**	$ 635.3
Less: Receivables not transferred	**295.2**	298.6
Net receivables transferred	**$ 399.2**	$ 336.7
Short-term debt due to asset securitization	**$ 399.2**	$ 336.7

During 2018 and 2017, $62.5 million and $26.7 million, respectively, was recorded as cash flows from financing activities related to the change in short-term borrowings due to securitization transactions. Fees associated with the securitization transactions were $2.6 million, $2.5 million and $2.3 million for the years ended December 31, 2018, 2017 and 2016, respectively. We remain responsible for collecting on the receivables securitized and the receivables cannot be transferred to another party.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

18. Other Commitments and Contingencies

A. Contractual Obligations. We have certain contractual obligations requiring payments at specified periods. The obligations include long-term debt, lease obligations, energy commodity contracts and obligations for various services including pipeline capacity and outsourcing of IT services. The total contractual obligations in existence at December 31, 2018 and their maturities were:

(in millions)	Total	2019	2020	2021	2022	2023	After
Long-term debt [1]	$ 7,029.6	$ 41.0	$ —	$ 63.6	$ 530.0	$ 600.0	$ 5,795.0
Capital leases[2]	322.4	23.0	22.5	22.6	22.1	19.8	212.4
Interest payments on long-term debt	6,311.7	319.8	318.6	318.6	315.0	289.0	4,750.7
Operating leases[3]	45.9	11.0	7.3	6.1	4.2	2.8	14.5
Energy commodity contracts	154.3	99.2	55.1	—	—	—	—
Service obligations:							
Pipeline service obligations	3,566.7	592.3	487.7	450.5	437.5	260.8	1,337.9
IT service obligations	211.0	68.3	60.0	47.1	35.6	—	—
Other service obligations	86.7	33.5	43.6	9.6	—	—	—
Other liabilities	24.2	24.2	—	—	—	—	—
Total contractual obligations	$ 17,752.5	$ 1,212.3	$ 994.8	$ 918.1	$ 1,344.4	$ 1,172.4	$ 12,110.5

(1) Long-term debt balance excludes unamortized issuance costs and discounts of $68.5 million.
(2) Capital lease payments shown above are inclusive of interest totaling $114.6 million.
(3) Operating lease balances do not include amounts for fleet leases that can be renewed beyond the initial lease term. The Company anticipates renewing the leases beyond the initial term, but the anticipated payments associated with the renewals do not meet the definition of expected minimum lease payments and therefore are not included above. Expected payments are $26.7 million in 2019, $22.4 million in 2020, $16.6 million in 2021, $12.3 million in 2022, $9.3 million in 2023 and $8.8 million thereafter.

Operating and Capital Lease Commitments. We lease assets in several areas of our operations including fleet vehicles and equipment, rail cars for coal delivery and certain operations centers. Payments made in connection with operating leases were $49.1 million in 2018, $49.5 million in 2017 and $52.0 million in 2016, and are primarily charged to operation and maintenance expense as incurred. Capital lease assets and related accumulated depreciation included in the Consolidated Balance Sheets were $213.9 million and $37.1 million at December 31, 2018, and $171.2 million and $32.4 million at December 31, 2017, respectively.

Purchase and Service Obligations. We have entered into various purchase and service agreements whereby we are contractually obligated to make certain minimum payments in future periods. Our purchase obligations are for the purchase of physical quantities of natural gas, electricity and coal. Our service agreements encompass a broad range of business support and maintenance functions which are generally described below.

Our subsidiaries have entered into various energy commodity contracts to purchase physical quantities of natural gas, electricity and coal. These amounts represent minimum quantities of these commodities we are obligated to purchase at both fixed and variable prices. To the extent contractual purchase prices are variable, obligations disclosed in the table above are valued at market prices as of December 31, 2018.

In July 2008, the IURC issued an order approving NIPSCO's purchase power agreements with subsidiaries of Iberdrola Renewables, Buffalo Ridge I LLC and Barton Windpower LLC. These agreements provide NIPSCO the opportunity and obligation to purchase up to 100 MW of wind power generated commencing in early 2009. The contracts extend 15 and 20 years, representing 50 MW of wind power each. No minimum quantities are specified within these agreements due to the variability of electricity generation from wind, so no amounts related to these contracts are included in the table above. Upon any termination of the agreements by NIPSCO for any reason (other than material breach by Buffalo Ridge I LLC or Barton Windpower LLC), NIPSCO may be required to pay a termination charge that could be material depending on the events giving rise to termination and the timing of the termination. NIPSCO began purchasing wind power in April 2009.

We have pipeline service agreements that provide for pipeline capacity, transportation and storage services. These agreements, which have expiration dates ranging from 2019 to 2045, require us to pay fixed monthly charges.

NIPSCO has contracts with three major rail operators providing for coal transportation services for which there are certain minimum payments. These service contracts extend for various periods through 2021.

In May and June 2017, we executed agreements with three separate IT service providers. The new agreements have terms ending at various dates throughout 2022.

Related to the NTSB's safety recommendations issued on November 14, 2018 (see "- C. Legal Proceedings" for further detail), we committed to the installation of over-pressurization protection devices at all of the remaining low pressure systems in our operating footprint. This installation is expected to result in a capital investment of approximately $150 million. This amount is not included in the table above.

B. Guarantees and Indemnities. We and certain subsidiaries enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries as part of normal business. Such agreements include guarantees and stand-by letters of credit. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. At December 31, 2018 and 2017, we had issued stand-by letters of credit of $10.2 million and $11.1 million, respectively, for the benefit of third parties.

C. Legal Proceedings.

On September 13, 2018, a series of fires and explosions occurred in Lawrence, Andover and North Andover, Massachusetts related to the delivery of natural gas by Columbia of Massachusetts. The Greater Lawrence Incident resulted in one fatality and a number of injuries, damaged multiple homes and businesses, and caused the temporary evacuation of significant portions of each municipality. The Massachusetts Governor's Office declared a state of emergency, authorizing the Massachusetts DPU to order another utility company to coordinate the restoration of utility services in Lawrence, Andover and North Andover. The incident resulted in the interruption of gas for approximately 7,500 gas meters, the majority of which serve residences and of which approximately 700 serve businesses, and the interruption of other utility service more broadly in the area. Columbia of Massachusetts has replaced the cast iron and bare steel gas pipeline system in the affected area and restored service to nearly all of the gas meters. See " - E. Other Matters - Greater Lawrence Pipeline Replacement" below for more information.

We are subject to inquiries by federal and state government authorities and regulatory agencies regarding the Greater Lawrence Incident. The NTSB, the U.S Attorney's office and the SEC have pending investigations related to the Greater Lawrence Incident, as described below. We are also subject to inquiries from the Massachusetts DPU and the Massachusetts Attorney General's Office. We are cooperating with all inquiries and investigations. The outcomes and impacts of the current investigations and any future investigations that may be commenced related to such inquiries are uncertain at this time.

NTSB Investigation. As noted above, the NTSB is investigating the Greater Lawrence Incident. The parties to the investigation include the PHMSA, the Massachusetts DPU, Columbia of Massachusetts, and police and fire first responders. We are cooperating with the NTSB and have provided information to assist in its ongoing investigation into relevant facts related to the event, the probable cause, and its development of safety recommendations.

According to the preliminary public report that the NTSB issued on October 11, 2018, an over-pressurization of a low pressure gas distribution system occurred that was related to work being done on behalf of Columbia of Massachusetts on a pipeline replacement project in Lawrence. According to the report, sensing lines detected a drop in pressure in a portion of mainline that was being abandoned, causing a regulator to open up and increase pressure in the system to a level that exceeded the maximum allowable operating pressure of the distribution system.

On November 14, 2018, the NTSB issued an urgent safety recommendation report regarding natural gas distribution system project development and review. In its report, the NTSB identified certain factors that it believes contributed to the Greater Lawrence Incident and made safety recommendations. The NTSB recommended that the Commonwealth of Massachusetts eliminate the professional engineer licensure exemption for public utility work and require a professional engineer's seal on public utility engineering drawings, which is now law in Massachusetts. The NTSB also made recommendations to us related to engineering plan and constructability review processes, records and documentation, management of change processes, and control procedures during modifications to gas mains. We are in the process of implementing these recommendations. The NTSB investigation is ongoing. While the NTSB investigation is pending, we are prohibited from disclosing information related to the investigation without approval from the NTSB.

Since the Greater Lawrence Incident, we have identified, and moved ahead with, new steps to enhance system safety and reliability and to safeguard against over-pressurization. Some of these measures have already been completed and others are in process. These Company-wide safety measures will include enhanced measures as called for in the NTSB's recommendations. We have committed to a program to install over-pressurization protection devices on all of our low-pressure systems, the cost of which is described in " - E. Other Matters."

Massachusetts Regulatory and Legislative Matters. The Massachusetts DPU has retained an independent evaluator to conduct a statewide examination of the safety of the natural gas distribution system and the operational and maintenance functions of natural gas companies in the Commonwealth of Massachusetts. Through authority granted by the Massachusetts Governor under the state of emergency, the Chair of the Massachusetts DPU will direct all natural gas distribution companies operating in the Commonwealth to fund the statewide examination. The statewide examination is underway and we are in the process of responding to the evaluator's information requests. The independent evaluator is expected to produce a report with recommendations. The examination is expected to complement, but not duplicate, the NTSB's investigation.

On November 30, 2018, Columbia of Massachusetts entered into a consent order with the Massachusetts DPU in connection with a notice of probable violation issued in March 2018, stemming from a 2016 report. The Division found that Columbia of Massachusetts violated certain pipeline safety regulations related to pressure limiting and regulating stations in Taunton, Massachusetts. As part of the consent order, Columbia of Massachusetts was fined $75,000 and entered into a compliance agreement under which it agreed to take several actions related to its pressure regulator stations within various timeframes, including the adoption of a Pipeline Safety Management System ("SMS"), the American Petroleum Institute's (API) Recommended Practice 1173. Columbia of Massachusetts is complying with the order.

On December 18, 2018, the Massachusetts DPU issued an order requiring Columbia of Massachusetts to enter into an agreement with a Massachusetts-based engineering firm to monitor Columbia of Massachusetts' remaining restoration and recovery work in the Greater Lawrence area. The order requires Columbia of Massachusetts to take measures to ensure that adequate heat and hot water and gas appliances are provided to all affected properties, repave all affected streets, roadways, sidewalks and other areas in accordance with applicable DPU standards and precedents, consult with the affected communities and discuss plans for restoring affected hard or soft surfaces, and replace all gas boilers and furnaces and other gas-fired equipment at affected residences. Under the order, all restoration work beginning in 2019 is required to be completed no later than October 31, 2019, unless an earlier or later date is agreed to with any of the affected communities. We have agreed to complete the work by September 15, 2019. Also, under the order, Columbia of Massachusetts will be required to maintain quantitative measures, which must be verified by officials of the affected communities, to track its progress in completing all of the remaining work. Estimates for the cost of this work are included in the estimated ranges of loss noted below, which is discussed in "- E. Other Matters - Greater Lawrence Incident Restoration" and " - Greater Lawrence Pipeline Replacement" below. Our failure to adhere to any of the requirements in the order may result in penalties of up to $1 million per violation.

Under Massachusetts law, the DPU is authorized to investigate potential violations of pipeline safety regulations and to assess a civil penalty of up to $209,000 for a violation of federal pipeline safety regulations. A separate violation occurs for each day of violation up to $2.1 million for a related series of violations. The Massachusetts DPU also is authorized to investigate potential violations of the Columbia of Massachusetts emergency response plan and to assess penalties of up to $250,000 per violation, or up to $20 million per related series of violations. Further, as a result of the declaration of emergency by the Governor, the DPU is authorized to investigate potential violations of the DPU's operational directives during the restoration efforts and assess penalties of up to $1 million per violation. The timing and outcome of any such investigations are uncertain at this time.

In December 2018, the President of Columbia of Massachusetts testified before a joint state legislative committee on telecommunications, utilities and energy with other industry officials about gas system safety in Massachusetts and regulatory oversight. Increased scrutiny related to these matters, including additional legislative oversight hearings and new legislative proposals, is expected during the current two-year legislative session.

On December 31, 2018, the Massachusetts Governor signed into law legislation requiring a certified professional engineer to review and approve gas pipeline work that could pose a "material risk" to public safety, consistent with the NTSB's recommendation. The Massachusetts DPU has issued interim guidelines and the existing moratorium has been lifted.

U.S. Department of Justice Investigation. The Company and Columbia of Massachusetts are subject to a criminal investigation related to the Greater Lawrence Incident that is being conducted under the supervision of the U.S. Attorney's Office for the District of Massachusetts. The initial grand jury subpoenas were served on the Company and Columbia of Massachusetts on September 24, 2018. The Company and Columbia of Massachusetts are cooperating with the investigation. We are unable to estimate the amount (or range of amounts) of reasonably possible losses associated with any civil or criminal penalties that could be imposed on the Company or Columbia of Massachusetts.

U.S. Congressional Hearing. In November 2018, executives of the Company and Columbia of Massachusetts testified at a U.S. Senate hearing regarding the Greater Lawrence Incident and natural gas pipeline safety. Increased scrutiny related to these matters, including additional federal congressional hearings and new legislative proposals, is expected in 2019.

SEC Investigation. On February 11, 2019, the SEC notified the Company that it is conducting an investigation of the Company related to disclosures made prior to the Greater Lawrence Incident. We intend to cooperate with the investigation.

Private Actions. Various lawsuits, including several purported class action lawsuits, have been filed by various affected residents or businesses in Massachusetts state courts against the Company and/or Columbia of Massachusetts in connection with the Greater Lawrence Incident. A special judge has been appointed to hear all pending and future cases and the class actions will be consolidated into one class action. On January 14, 2019, the special judge granted the parties' joint motion to stay all cases for 90 days to allow mediation. The parties are in the process of filing a request with the special judge to extend this period. The class action lawsuits allege varying causes of action, including those for strict liability for ultra-hazardous activity, negligence, private nuisance, public nuisance, premises liability, trespass, breach of warranty, breach of contract, failure to warn, unjust enrichment, consumer protection act claims, negligent and reckless infliction of emotional distress, and gross negligence, and seek actual compensatory damages, plus treble damages, and punitive damages. Many residents and business owners have submitted individual damage claims to Columbia of Massachusetts. We also have received notice from three parties indicating an intent to assert wrongful death claims. In Massachusetts, punitive damages are available in a wrongful death action upon proof of gross negligence or willful or reckless conduct causing the death. In addition, the Commonwealth of Massachusetts and the municipalities of Lawrence, Andover and North Andover are seeking reimbursement from Columbia of Massachusetts for their respective expenses incurred in connection with the Greater Lawrence Incident. The outcomes and impacts of the private actions are uncertain at this time.

Financial Impact. During the year ended December 31, 2018, we expensed approximately $757 million for estimated third-party claims related to the Greater Lawrence Incident, including, but not limited to, personal injury and property damage claims, damage to infrastructure, business interruption claims, and other damage claims, which include mutual aid payments to other utilities assisting with the restoration effort; gas-fueled appliance replacement, repair and related services for impacted customers; temporary lodging for displaced customers; evacuation expense claims; and claims-related legal fees. We estimate that total costs related to third-party claims resulting from the incident will range from $757 million to $790 million, depending on the final outcome of ongoing reviews and the number, nature, and value of third-party claims. The amounts set forth above do not include non-claims related expenses resulting from the incident or the estimated capital cost of the pipeline replacement, which is set forth in " - E. Other Matters - Greater Lawrence Incident Restoration" and " - Greater Lawrence Pipeline Replacement," respectively, below.

The process for estimating costs associated with third-party claims relating to the Greater Lawrence Incident requires management to exercise significant judgment based on a number of assumptions and subjective factors. As more information becomes known, including additional information resulting from the NTSB investigation, management's estimates and assumptions regarding the financial impact of the Greater Lawrence Incident may change. The increase in estimated total costs related to third-party claims from those disclosed in our Form 10-Q for the quarter ended September 30, 2018 resulted primarily from receiving additional information regarding the required scope of the restoration work inside the affected homes and the extended period of time over which the restoration work would take place.

It is not possible at this time to reasonably estimate the total amount of any expenses associated with government investigations and fines, penalties or settlements with governmental authorities, including the Massachusetts DPU and other regulators, that we may incur in connection with the Greater Lawrence Incident. Therefore, the foregoing amounts do not include estimates of the total amount that we may incur for any such fines, penalties or settlements.

Expenses described above are presented within "Operation and maintenance" in our Statements of Consolidated Income.

We maintain liability insurance for damages in the approximate amount of $800 million and property insurance for gas pipelines and other applicable property in the approximate amount of $300 million. Total expenses related to the incident have exceeded the total amount of liability insurance coverage available under our policies. Certain of these expenses may be covered under our property insurance. While we believe that a substantial amount of expenses related to the Greater Lawrence Incident will be covered by insurance, insurers providing property and liability insurance to the Company or Columbia of Massachusetts may raise defenses to coverage under the terms and conditions of the respective insurance policies which contain various exclusions and conditions that could limit the amount of insurance proceeds to the Company or Columbia of Massachusetts. We are not able to estimate the amount of expenses that will not be covered or exceed insurance limits, but these amounts could be material to our financial statements. Certain types of damages, expenses or claimed costs, such as fines or penalties, may be excluded under the policies. An amount of $135 million for insurance recoveries was recorded through December 31, 2018. Of this amount, $5 million was collected during 2018. The remaining insurance receivable balance of $130 million is presented within "Accounts receivable." To the extent that we are not successful in obtaining insurance recoveries in the amount recorded for such recoveries as of December 31, 2018, it could result in a charge against "Operation and maintenance" expense. We are currently unable to predict the amount and timing of additional future insurance recoveries.

In addition, we are party to certain other claims and legal proceedings arising in the ordinary course of business, none of which is deemed to be individually material at this time. Due to the inherent uncertainty of litigation, there can be no assurance that the resolution of any particular claim or proceeding related to the Greater Lawrence Incident or otherwise would not have a material adverse effect on our results of operations, financial position or liquidity. If one or more of such matters were decided against us, the effects could be material to our results of operations in the period in which we would be required to record or adjust the related liability and could also be material to our cash flows in the periods that we would be required to pay such liability.

D. Environmental Matters. Our operations are subject to environmental statutes and regulations related to air quality, water quality, hazardous waste and solid waste. We believe that we are in substantial compliance with the environmental regulations currently applicable to our operations.

It is management's continued intent to address environmental issues in cooperation with regulatory authorities in such a manner as to achieve mutually acceptable compliance plans. However, there can be no assurance that fines and penalties will not be incurred. Management expects a significant portion of environmental assessment and remediation costs to be recoverable through rates for certain of our companies.

As of December 31, 2018 and 2017, we had recorded a liability of $101.2 million and $111.4 million, respectively, to cover environmental remediation at various sites. The current portion of this liability is included in "Legal and environmental" in the Consolidated Balance Sheets. The noncurrent portion is included in "Other noncurrent liabilities." We recognize costs associated with environmental remediation obligations when the incurrence of such costs is probable and the amounts can be reasonably estimated. The original estimates for remediation activities may differ materially from the amount ultimately expended. The actual future expenditures depend on many factors, including currently enacted laws and regulations, the nature and extent of impact and the method of remediation. These expenditures are not currently estimable at some sites. We periodically adjust our liability as information is collected and estimates become more refined.

Electric Operations' compliance estimates disclosed below are reflective of NIPSCO's Integrated Resource Plan submitted to the IURC on October 31, 2018. See section " - E. Other Matters - NIPSCO 2018 Integrated Resource Plan," below for additional information.

Air

Future legislative and regulatory programs could significantly limit allowed GHG emissions or impose a cost or tax on GHG emissions. Additionally, rules that increase methane leak detection, require emission reductions or impose additional requirements for natural gas facilities could restrict GHG emissions and impose additional costs. NiSource will carefully monitor all GHG reduction proposals and regulations.

CPP and ACE Rules. On October 23, 2015, the EPA issued the CPP to regulate CO_2 emissions from existing fossil-fuel EGUs under section 111(d) of the CAA. The U.S. Supreme Court has stayed implementation of the CPP until litigation is decided on its merits, and the EPA has proposed to repeal the CPP. On August 31, 2018, the EPA published a proposal to replace the CPP with the ACE rule, which establishes guidelines for states to use when developing plans to reduce CO_2 emissions from existing coal-fired EGUs. The proposal would provide states three years after a final rule is issued to develop state-specific plans, and the EPA would have twelve months to act on a complete state plan submittal. Within two years after a finding of failure to submit a complete plan, or disapproval of a state plan, the EPA would issue a federal plan. NIPSCO will continue to monitor this matter and cannot estimate its impact at this time.

Waste

CERCLA. Our subsidiaries are potentially responsible parties at waste disposal sites under the CERCLA (commonly known as Superfund) and similar state laws. Under CERCLA, each potentially responsible party can be held jointly, severally and strictly liable for the remediation costs as the EPA, or state, can allow the parties to pay for remedial action or perform remedial action themselves and request reimbursement from the potentially responsible parties. Our affiliates have retained CERCLA environmental liabilities, including remediation liabilities, associated with certain current and former operations. These liabilities are not material to the Consolidated Financial Statements.

MGP. A program has been instituted to identify and investigate former MGP sites where Gas Distribution Operations subsidiaries or predecessors may have liability. The program has identified 63 such sites where liability is probable. Remedial actions at many of these sites are being overseen by state or federal environmental agencies through consent agreements or voluntary remediation agreements.

We utilize a probabilistic model to estimate our future remediation costs related to MGP sites. The model was prepared with the assistance of a third party and incorporates our experience and general industry experience with remediating MGP sites. We complete an annual refresh of the model in the second quarter of each fiscal year. No material changes to the estimated future remediation costs were noted as a result of the refresh completed as of June 30, 2018. Our total estimated liability related to the facilities subject to remediation was $97.5 million and $106.9 million at December 31, 2018 and 2017, respectively. The liability represents our best estimate of the probable cost to remediate the facilities. We believe that it is reasonably possible that remediation costs could vary by as much as $20 million in addition to the costs noted above. Remediation costs are estimated based on the best available information, applicable remediation standards at the balance sheet date, and experience with similar facilities.

CCRs. On April 17, 2015, the EPA issued a final rule for regulation of CCRs. The rule regulates CCRs under the RCRA Subtitle D, which determines them to be nonhazardous. The rule is implemented in phases and requires increased groundwater monitoring, reporting, recordkeeping and posting of related information to the Internet. The rule also establishes requirements related to CCR management and disposal. The rule will allow NIPSCO to continue its byproduct beneficial use program.

The publication of the CCR rule resulted in revisions to previously recorded legal obligations associated with the retirement of certain NIPSCO facilities. The actual asset retirement costs related to the CCR rule may vary substantially from the estimates used to record the increased asset retirement obligation due to the uncertainty about the compliance strategies that will be used and the preliminary nature of available data used to estimate costs. In addition, to comply with the rule, NIPSCO is incurring capital expenditures to modify its infrastructure and manage CCRs. Capital compliance costs are currently expected to total approximately $193 million. As allowed by the EPA, NIPSCO will continue to collect data over time to determine the specific compliance solutions and associated costs and, as a result, the actual costs may vary.

NIPSCO filed a petition on November 1, 2016 with the IURC seeking approval of the projects and recovery of the costs associated with CCR compliance. On June 9, 2017, NIPSCO filed with the IURC a settlement reached with certain parties regarding the CCR projects and treatment of associated costs. The IURC approved the settlement in an order on December 13, 2017.

Water

ELG. On November 3, 2015, the EPA issued a final rule to amend the ELG and standards for the Steam Electric Power Generating category. The final rule became effective January 4, 2016. Based upon a preliminary study of the November 3, 2015 final rule, capital compliance costs were expected to be approximately $170.0 million. However, NIPSCO does not anticipate material ELG compliance costs based on the preferred option announced as part of NIPSCO's 2018 Integrated Resource Plan (discussed below).

E. Other Matters.

Bailly Generating Station. On February 1, 2018, as previously approved by MISO, NIPSCO commenced a four-month outage of Bailly Generating Station Unit 8 in order to begin work on converting the unit to a synchronous condenser (a piece of equipment designed to maintain voltage to ensure continued reliability on the transmission system). Approximately $15 million of net book value of Unit 8 remained in “Net Utility Plant” as it will remain used and useful after completion of the synchronous condenser, while the remaining net book value of approximately $142 million was reclassified to “Regulatory assets (noncurrent)” on the Consolidated Balance Sheets. On May 31, 2018, Units 7 and 8 were retired from service. These units had a combined generating capacity of approximately 460 MW. As a result of the retirement, the remaining net book value of Unit 7 of approximately $103 million was reclassified to “Regulatory assets (noncurrent)” on the Consolidated Balance Sheets.These amounts continue to be amortized at a rate consistent with their inclusion in customer rates. Refer to Note 8, "Regulatory Matters," for additional information.

NIPSCO Pure Air. NIPSCO had a service agreement with Pure Air, a general partnership between Air Products and Chemicals, Inc. and First Air Partners LP, under which Pure Air provided scrubber services to reduce sulfur dioxide emissions for Units 7 and 8 at the Bailly Generating Station. Payments under this agreement were $8.3 million and $22.0 million for the years ended December 31, 2018 and 2017, respectively.

As discussed above in "Bailly Generating Station," NIPSCO retired the generation station units serviced by Pure Air on May 31, 2018. In December 2016, as allowed by the provisions of the service agreement, NIPSCO provided Pure Air formal notice of intent to terminate the service agreement, effective May 31, 2018. Providing this notice to Pure Air triggered a contract termination liability of $16 million which was recorded in fourth quarter of 2016. In connection with the closure of Bailly Units 7 and 8, NIPSCO paid the termination payment to Pure Air during the second quarter of 2018. Cash flows associated with this payment are presented within operating activities on the Statements of Consolidated Cash Flows.

NIPSCO 2018 Integrated Resource Plan. Multiple factors, but primarily economic ones, including low natural gas prices, advancing cost effective renewable technology and increasing capital and operating costs associated with existing coal plants, have led NIPSCO to conclude in its October 2018 Integrated Resource Plan submission that NIPSCO's current fleet of coal generation facilities will be retired earlier than previous Integrated Resource Plan's had indicated.

The Integrated Resource Plan evaluated demand-side and supply-side resource alternatives to reliably and cost effectively meet NIPSCO customers' future energy requirements over the ensuing 20 years. The preferred option within the Integrated Resource Plan retires R.M. Schahfer Generating Station (Units 14, 15, 17, and 18) by 2023 and Michigan City Generating Station (Unit 12) by 2028. These units represent 2,080 MW of generating capacity, equal to 72% of NIPSCO's remaining generating capacity (and 100% of NIPSCO's remaining coal-fired generating capacity) after the retirement of Bailly Units 7 and 8 discussed above.

The current replacement plan includes renewable sources of energy, including wind, solar, and battery storage to be obtained through a combination of NIPSCO ownership and PPAs.

In January 2019, NIPSCO executed two 20 year PPAs to purchase 100% of the output from renewable generation facilities at a fixed price per MWh. The facilities supplying the energy will have a combined nameplate capacity of approximately 700 MW. NIPSCO's purchase requirement under the PPAs is dependent on satisfactory approval of the PPAs by the IURC. NIPSCO submitted the PPAs to the IURC for approval in February 2019. An IURC order is anticipated in the second quarter of 2019. If approved by the IURC, payments under the PPAs will not begin until the associated generation facilities are constructed by the owner / seller which is expected to be complete by the end of 2020.

Also in January 2019, NIPSCO executed a BTA with a developer to construct a renewable generation facility with a nameplate capacity of approximately 100 MW. Once complete, ownership of the facility would be transferred to a partnership owned by NIPSCO, the developer and an unrelated tax equity partner. The aforementioned partnership structure will result in full NIPSCO ownership after the PTC are monetized from the project (approximately 10 years after the facility goes into service). NIPSCO's purchase requirement under the BTA is dependent on satisfactory approval of the BTA by the IURC and timely completion of construction. The estimated procedural timeline for receiving an IURC order is the same as the aforementioned PPAs with required FERC filings occurring after receiving the IURC order. Construction of the facility is expected to be complete by the end of 2020.

Greater Lawrence Incident Restoration. During the year ended December 31, 2018, we expensed approximately $1,023 million in connection with the Greater Lawrence Incident. Included in this expense is approximately $757 million for estimated third-party claims associated with the incident as described above in " - C. Legal Proceedings." The additional $266 million included in the expense recorded includes certain consulting costs, claims center costs, charitable contributions, labor and related expenses, lodging and meals for employees and contractors, and security costs in connection with the incident. We expect to incur a total of $330 million to $345 million in such incident-related costs, depending on the incurrence of future restoration work. The amounts set forth above do not include the estimated capital cost of the pipeline replacement, which is set forth below. The increase in estimated total incident-related expenses from those disclosed in our Form 10-Q for the quarter ended September 30, 2018 resulted primarily from receiving additional information regarding the extended period of time over which the restoration work would take place, higher than anticipated costs from vendors and increased estimates for non-claims-related legal fees.

We maintain liability insurance for damages in the approximate amount of $800 million and property insurance for gas pipelines and other applicable property in the approximate amount of $300 million. Total expenses related to the incident have exceeded the total amount of liability insurance coverage available under our policies. Certain of these expenses may be covered under our property insurance. While we believe that a substantial amount of expenses related to the Greater Lawrence Incident will be covered by insurance, insurers providing property and liability insurance to the Company or Columbia of Massachusetts may raise defenses to coverage under the terms and conditions of the respective insurance policies which contain various exclusions and conditions that could limit the amount of insurance proceeds to the Company or Columbia of Massachusetts. We are not able to estimate the amount of expenses that will not be covered or exceed insurance limits, but these amounts could be material to our financial statements. Certain types of damages, expenses or claimed costs, such as fines or penalties, may be excluded under the policies. As discussed above in "- C. Legal Proceedings," $135 million of insurance recoveries were recorded through December 31, 2018. Of this amount, $5 million was collected during 2018. We are currently unable to predict the amount and timing of future insurance recoveries. To the extent that we are not successful in obtaining insurance recoveries in the amount recorded for such recoveries as of December 31, 2018, it could result in a charge against "Operation and maintenance" expense.

Costs associated with charitable contributions are presented within "Other, Net" in our Statements of Consolidated Income. All other expenses incurred are presented within "Operation and maintenance." Substantially all of the $292 million liability for third-party claims and other incident-related costs remaining as of December 31, 2018 is presented within current liabilities in our Consolidated Balance Sheets. The remaining insurance receivable balance of $130 million is presented within "Accounts receivable."

Greater Lawrence Pipeline Replacement. In connection with the Greater Lawrence Incident, Columbia of Massachusetts, in cooperation with the Massachusetts Governor's Office, replaced the entire affected 45-mile cast iron and bare steel pipeline system that delivers gas to approximately 7,500 gas meters, the majority of which serve residences and of which approximately 700 serve businesses impacted in the Greater Lawrence Incident. This system was replaced with plastic distribution mains and service lines, as well as enhanced safety features such as pressure regulation and excess flow valves at each premise. At the request of the Massachusetts DPU, which was instructed by the Massachusetts Governor through his executive authority under a state of emergency, Columbia of Massachusetts hired an outside contractor to serve as the Chief Recovery Officer for the Greater Lawrence Incident, responsible for command, control and communications. Columbia of Massachusetts restored gas service to nearly all homes and workplaces in December 2018. With the restoration and recovery efforts now substantially complete, the service of the Chief Recovery Officer is complete and the next phase of the effort is being managed by Columbia of Massachusetts under the third party oversight of a Massachusetts-based engineering firm as set forth above under " - C. Legal Proceedings."

We incurred approximately $167 million of capital spend for the pipeline replacement during 2018. We estimate this replacement work will cost between $220 million and $230 million in total. Columbia of Massachusetts has provided notice to its property insurer of the Greater Lawrence Incident and discussions around the claim and recovery have commenced. The recovery of any capital investment not reimbursed through insurance will be addressed in a future regulatory proceeding. The outcome of such a proceeding is uncertain. In accordance with ASC 980-360, if it becomes probable that a portion of the pipeline replacement cost will not be recoverable through customer rates and an amount can be reasonably estimated, we will reduce our regulated plant balance for the amount of the probable disallowance and record an associated charge to earnings. This could result in a material adverse effect to our financial condition, results of operations and cash flows. Additionally, if a rate order is received allowing recovery of the investment with no or reduced return on investment, a loss on disallowance may be required.

In addition, we have committed to an approximately $150 million capital investment program to install over-pressurization protection devices on all of our low-pressure systems as described above in "-C. Legal Proceedings." These devices operate like circuit-breakers, so that if operating pressure is too high or too low, regardless of the cause, they are designed to immediately shut down gas to the system. The program also includes installing remote monitoring devices on all low-pressure systems, enabling gas control centers to continuously monitor pressure at regulator stations in real time. In addition, we have conducted a field survey of all regulator stations and initiated an engineering review of those regulator stations; we are verifying and enhancing our maps and records of low-pressure regulator stations; and we initiated a process so that our personnel will be present whenever excavation work is being done in close proximity to a regulator station.

19. Accumulated Other Comprehensive Loss

The following table displays the activity of Accumulated Other Comprehensive Loss, net of tax:

(in millions)	Gains and Losses on Securities[1]	Gains and Losses on Cash Flow Hedges[1]	Pension and OPEB Items[1]	Accumulated Other Comprehensive Loss[1]
Balance as of January 1, 2016	**$ (0.5)**	**$ (15.5)**	**$ (19.1)**	**$ (35.1)**
Other comprehensive loss before reclassifications	—	7.1	0.5	7.6
Amounts reclassified from accumulated other comprehensive loss	(0.1)	1.5	1.0	2.4
Net current-period other comprehensive loss	(0.1)	8.6	1.5	10.0
Balance as of December 31, 2016	**$ (0.6)**	**$ (6.9)**	**$ (17.6)**	**$ (25.1)**
Other comprehensive income before reclassifications	0.6	(24.2)	1.9	(21.7)
Amounts reclassified from accumulated other comprehensive loss	0.2	1.7	1.5	3.4
Net current-period other comprehensive income (loss)	0.8	(22.5)	3.4	(18.3)
Balance as of December 31, 2017	**$ 0.2**	**$ (29.4)**	**$ (14.2)**	**$ (43.4)**
Other comprehensive income (loss) before reclassifications	(3.0)	55.8	(4.4)	48.4
Amounts reclassified from accumulated other comprehensive loss	0.4	(33.1)	—	(32.7)
Net current-period other comprehensive income (loss)	(2.6)	22.7	(4.4)	15.7
Reclassification due to adoption of ASU 2018-02 (Refer to Note 2)	—	(6.3)	(3.2)	(9.5)
Balance as of December 31, 2018	**$ (2.4)**	**$ (13.0)**	**$ (21.8)**	**$ (37.2)**

(1)All amounts are net of tax. Amounts in parentheses indicate debits.

20. Other, Net

Year Ended December 31, *(in millions)*	**2018**	2017	2016
Interest Income	**$ 6.6**	$ 4.6	$ 3.4
AFUDC Equity	**14.2**	12.6	11.6
Charitable Contributions[1]	**(45.3)**	(19.9)	(4.5)
Pension and other postretirement non-service cost[2]	**18.0**	(10.6)	(7.9)
Interest rate swap settlement gain[3]	**46.2**	—	—
Miscellaneous	**3.8**	(0.2)	(5.6)
Total Other, net	**$ 43.5**	$ (13.5)	$ (3.0)

(1) Includes $20.7 million related to the Greater Lawrence Incident. See Note 18, "Other Commitments and Contingencies" for additional information.
(2) See Note 11, "Pension and Other Postretirement Benefits" for additional information.
(3) See Note 9, "Risk Management Activities" for additional information.

21. Interest Expense, Net

Year Ended December 31, *(in millions)*		**2018**		2017		2016
Interest on long-term debt	**$**	**342.2**	$	354.8	$	352.3
Interest on short-term borrowings		**31.8**		14.9		9.2
Debt discount/cost amortization		**7.7**		7.2		7.6
Accounts receivable securitization fees		**2.6**		2.5		2.3
Allowance for borrowed funds used and interest capitalized during construction		**(9.1)**		(6.2)		(5.6)
Debt-based post-in-service carrying charges		**(35.0)**		(36.4)		(35.1)
Other		**13.1**		16.4		18.8
Total Interest Expense, net	**$**	**353.3**	$	353.2	$	349.5

22. Segments of Business

At December 31, 2018, our operations are divided into two primary reportable segments. The Gas Distribution Operations segment provides natural gas service and transportation for residential, commercial and industrial customers in Ohio, Pennsylvania, Virginia, Kentucky, Maryland, Indiana and Massachusetts. The Electric Operations segment provides electric service in 20 counties in the northern part of Indiana.

The following table provides information about our reportable segments. We use operating income as our primary measurement for each of the reported segments and make decisions on finance, dividends and taxes at the corporate level on a consolidated basis. Segment revenues include intersegment sales to affiliated subsidiaries, which are eliminated in consolidation. Affiliated sales are recognized on the basis of prevailing market, regulated prices or at levels provided for under contractual agreements. Operating income is derived from revenues and expenses directly associated with each segment.

Year Ended December 31, *(in millions)*		**2018**		2017		2016
Operating Revenues						
Gas Distribution Operations						
Unaffiliated	**$**	**3,406.4**	$	3,087.9	$	2,818.2
Intersegment		**13.1**		14.2		12.4
Total		**3,419.5**		3,102.1		2,830.6
Electric Operations						
Unaffiliated		**1,707.4**		1,785.7		1,660.8
Intersegment		**0.8**		0.8		0.8
Total		**1,708.2**		1,786.5		1,661.6
Corporate and Other						
Unaffiliated		**0.7**		1.0		13.5
Intersegment		**517.6**		510.8		413.3
Total		**518.3**		511.8		426.8
Eliminations		**(531.5)**		(525.8)		(426.5)
Consolidated Operating Revenues	**$**	**5,114.5**	$	4,874.6	$	4,492.5

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

Year Ended December 31, *(in millions)*	**2018**	2017	2016
Operating Income (Loss)			
Gas Distribution Operations	**$ (254.1)**	$ 550.1	$ 569.7
Electric Operations	**386.1**	367.4	301.3
Corporate and Other	**(7.3)**	3.7	(4.9)
Consolidated Operating Income	**$ 124.7**	$ 921.2	$ 866.1
Depreciation and Amortization			
Gas Distribution Operations	**$ 301.0**	$ 269.3	$ 252.9
Electric Operations	**262.9**	277.8	274.5
Corporate and Other	**35.7**	23.2	19.7
Consolidated Depreciation and Amortization	**$ 599.6**	$ 570.3	$ 547.1
Assets			
Gas Distribution Operations	**$ 13,527.0**	$ 12,048.8	$ 11,096.4
Electric Operations	**5,735.2**	5,478.6	5,233.3
Corporate and Other	**2,541.8**	2,434.3	2,362.2
Consolidated Assets	**$ 21,804.0**	$ 19,961.7	$ 18,691.9
Capital Expenditures[(1)]			
Gas Distribution Operations	**$ 1,315.3**	$ 1,125.6	$ 1,054.4
Electric Operations	**499.3**	592.4	420.6
Corporate and Other	**—**	35.8	15.4
Consolidated Capital Expenditures	**$ 1,814.6**	$ 1,753.8	$ 1,490.4

[(1] Amounts differ from those presented on the Statements of Consolidated Cash Flows primarily due to the inclusion of capital expenditures included in current liabilities and AFUDC Equity.

23. Quarterly Financial Data (Unaudited)

Quarterly financial data does not always reveal the trend of our business operations due to nonrecurring items and seasonal weather patterns, which affect earnings and related components of revenue and operating income.

(in millions, except per share data)	First Quarter[1]	Second Quarter[2]	Third Quarter[3]	Fourth Quarter[4]
2018				
Operating Revenues	$ 1,750.8	$ 1,007.0	$ 895.0	$ 1,461.7
Operating Income (Loss)	400.6	118.4	(315.9)	(78.4)
Net Income (Loss)	276.1	24.5	(339.5)	(11.7)
Preferred Dividends	—	(1.3)	(5.6)	(8.1)
Net Income (Loss) Available to Common Shareholders	276.1	23.2	(345.1)	(19.8)
Earnings (Loss) Per Share				
Basic Earnings (Loss) Per Share	$ 0.82	$ 0.07	$ (0.95)	$ (0.05)
Diluted Earnings (Loss) Per Share	$ 0.81	$ 0.07	$ (0.95)	$ (0.05)
2017				
Operating Revenues	$ 1,598.6	$ 990.7	$ 917.0	$ 1,368.3
Operating Income	415.4	124.0	111.2	270.6
Net Income (Loss)	211.3	(44.4)	14.0	(52.4)
Earnings (Loss) Per Share				
Basic Earnings (Loss) Per Share	$ 0.65	$ (0.14)	$ 0.04	$ (0.16)
Diluted Earnings (Loss) Per Share	$ 0.65	$ (0.14)	$ 0.04	$ (0.16)

(1) Net income for the first quarter of 2018 was impacted by an interest rate swap settlement gain of $21.2 million (pretax). See Note 9, "Risk Management Activities" for additional information.
(2) Net income for the second quarter of 2017 was impacted by a $111.5 million loss (pretax) on an early extinguishment of long-term debt. See Note 14, "Long-Term Debt" for additional information.
(3) Net income for the third quarter of 2018 was impacted by approximately $462 million in expenses (pretax) related to the Greater Lawrence Incident restoration and a $33.0 million loss (pretax) on an early extinguishment of long-term debt. See Note 18-E, "Other Matters" and Note 14, "Long-Term Debt" for additional information.
(4) Net income for the fourth quarter of 2018 was impacted by approximately $426 million in expenses (pretax, net of insurance recoveries) related to the Greater Lawrence Incident restoration, partially offset by an interest rate swap settlement gain of $25.0 million (pretax) and a $120.7 million income tax benefit from true-ups to reflect regulatory outcomes associated with excess deferred income taxes. Net income for the fourth quarter of 2017 was impacted by a $161.1 million increase in tax expense as a result of implementing the provisions of the TCJA. See Note 18-E, "Other Matters," Note 9, "Risk Management Activities" and Note 10, "Income Taxes" for additional information.

24. Supplemental Cash Flow Information

The following table provides additional information regarding our Consolidated Statements of Cash Flows for the years ended December 31, 2018, 2017 and 2016:

Year Ended December 31, *(in millions)*	2018	2017	2016
Supplemental Disclosures of Cash Flow Information			
Non-cash transactions:			
Capital expenditures included in current liabilities	**$ 152.0**	$ 173.0	$ 125.3
Assets acquired under a capital lease	**54.6**	11.5	4.0
Reclassification of other property to regulatory assets[1]	**245.3**	—	—
Assets recorded for asset retirement obligations[2]	**78.1**	11.4	6.9
Schedule of interest and income taxes paid:			
Cash paid for interest, net of interest capitalized amounts	**$ 354.2**	$ 339.9	$ 337.8
Cash paid for income taxes, net of refunds	**3.3**	5.5	8.0

[1]See Note 8 "Regulatory Matters" for additional information.
[2]See Note 7 "Asset Retirement Obligations" for additional information.

NISOURCE INC.

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS

Twelve months ended December 31, 2018

($ in millions)	Balance Jan. 1, 2018	Additions: Charged to Costs and Expenses	Additions: Charged to Other Account [1]	Deductions for Purposes for which Reserves were Created	Balance Dec. 31, 2018
Reserves Deducted in Consolidated Balance Sheet from Assets to Which They Apply:					
Reserve for accounts receivable	$ 18.3	$ 20.2	$ 43.7	$ 61.1	$ 21.1
Reserve for other investments	3.0	—	—	—	3.0

Twelve months ended December 31, 2017

($ in millions)	Balance Jan. 1, 2017	Additions: Charged to Costs and Expenses	Additions: Charged to Other Account [1]	Deductions for Purposes for which Reserves were Created	Balance Dec. 31, 2017
Reserves Deducted in Consolidated Balance Sheet from Assets to Which They Apply:					
Reserve for accounts receivable	$ 23.3	$ 14.8	$ 39.1	$ 58.9	$ 18.3
Reserve for other investments	3.0	—	—	—	3.0

Twelve months ended December 31, 2016

($ in millions)	Balance Jan. 1, 2016	Additions: Charged to Costs and Expenses	Additions: Charged to Other Account [1]	Deductions for Purposes for which Reserves were Created	Balance Dec. 31, 2016
Reserves Deducted in Consolidated Balance Sheet from Assets to Which They Apply:					
Reserve for accounts receivable	$ 20.3	$ 19.7	$ 48.5	$ 65.2	$ 23.3
Reserve for other investments	3.0	—	—	—	3.0

[1] Charged to Other Accounts reflects the deferral of bad debt expense to a regulatory asset.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Our chief executive officer and chief financial officer are responsible for evaluating the effectiveness of disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)). Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by the Company in reports that are filed or submitted under the Exchange Act are accumulated and communicated to management, including our chief executive officer and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our chief executive officer and chief financial officer concluded that, as of the end of the period covered by this report, disclosure controls and procedures were effective to provide reasonable assurance that financial information was processed, recorded and reported accurately.

Management's Annual Report on Internal Control over Financial Reporting

Our management, including our chief executive officer and chief financial officer, are responsible for establishing and maintaining internal control over financial reporting, as such term is defined under Rule 13a-15(f) or Rule 15d-15(f) promulgated under the Exchange Act. However, management would note that a control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our management has adopted the 2013 framework set forth in the Committee of Sponsoring Organizations of the Treadway Commission report, Internal Control - Integrated Framework, the most commonly used and understood framework for evaluating internal control over financial reporting, as its framework for evaluating the reliability and effectiveness of internal control over financial reporting. During 2018, we conducted an evaluation of our internal control over financial reporting. Based on this evaluation, management concluded that our internal control over financial reporting was effective as of the end of the period covered by this annual report.

Deloitte & Touche LLP, our independent registered public accounting firm, issued an attestation report on our internal controls over financial reporting which is contained in Item 8, "Financial Statements and Supplementary Data."

Changes in Internal Controls

There have been no changes in our internal control over financial reporting during the most recently completed quarter covered by this report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Except for the information required by this item with respect to our executive officers included at the end of Part I of this report on Form 10-K, the information required by this Item 10 is incorporated herein by reference to the discussion in "Proposal 1 Election of Directors," "Corporate Governance," and "Section 16(a) Beneficial Ownership Reporting Compliance," of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 7, 2019.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item 11 is incorporated herein by reference to the discussion in "Corporate Governance - Compensation Committee Interlocks and Insider Participation," "Director Compensation," "Executive Compensation," and "Executive Compensation - Compensation Committee Report," of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 7, 2019.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item 12 is incorporated herein by reference to the discussion in "Security Ownership of Certain Beneficial Owners and Management" and "Equity Compensation Plan Information" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 7, 2019.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item 13 is incorporated herein by reference to the discussion in "Corporate Governance - Policies and Procedures with Respect to Transactions with Related Persons" and "Corporate Governance - Director Independence" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 7, 2019.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item 14 is incorporated herein by reference to the discussion in "Independent Auditor Fees" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 7, 2019.

PART IV

NISOURCE INC.

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

Financial Statements and Financial Statement Schedules

The following financial statements and financial statement schedules filed as a part of the Annual Report on Form 10-K are included in Item 8, "Financial Statements and Supplementary Data."

Exhibits

The exhibits filed herewith as a part of this report on Form 10-K are listed on the Exhibit Index below. Each management contract or compensatory plan or arrangement of ours, listed on the Exhibit Index, is separately identified by an asterisk.

Pursuant to Item 601(b), paragraph (4)(iii)(A) of Regulation S-K, certain instruments representing long-term debt of our subsidiaries have not been included as Exhibits because such debt does not exceed 10% of the total assets of ours and our subsidiaries on a consolidated basis. We agree to furnish a copy of any such instrument to the SEC upon request.

EXHIBIT NUMBER	DESCRIPTION OF ITEM
(1.1)	Form of Equity Distribution Agreement (incorporated by reference to Exhibit 1.1 to the NiSource Inc. Form 8-K filed on November 1, 2018).
(1.2)	Form of Master Forward Sale Confirmation (incorporated by reference to Exhibit 1.2 to the NiSource Inc. Form 8-K filed on November 1, 2018).
(2.1)	Separation and Distribution Agreement, dated as of June 30, 2015, by and between NiSource Inc. and Columbia Pipeline Group, Inc. (incorporated by reference to Exhibit 2.1 to the NiSource Inc. Form 8-K filed on July 2, 2015).
(3.1)	Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the NiSource Inc. Form 8-K filed on January 26, 2018).
(3.2)	Bylaws of NiSource Inc., as amended and restated through January 26, 2018 (incorporated by reference to Exhibit 3.1 to the NiSource Inc. Form 8-K filed on January 26, 2018).
(3.3)	Certificate of Designations of 5.65% Series A Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock (incorporated by reference to Exhibit 3.1 of the NiSource Inc. Form 8-K filed on June 12, 2018).
(3.4)	Form of Certificate of Designations of 6.50% Series B Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock (incorporated by reference to Exhibit 3.1 of the NiSource Inc. Form 8-K filed on November 29, 2018).
(3.5)	Certificate of Designations of 6.50% Series B Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock (incorporated by reference to Exhibit 3.1 of the NiSource Inc. Form 8-K filed on December 6, 2018).
(3.6)	Certificate of Designations of Series B-1 Preferred Stock (incorporated by reference to Exhibit 3.1 to the NiSource Inc. Form 8-K filed on December 27, 2018).
(4.1)	Indenture, dated as of March 1, 1988, by and between Northern Indiana Public Service Company ("NIPSCO") and Manufacturers Hanover Trust Company, as Trustee (incorporated by reference to Exhibit 4 to the NIPSCO Registration Statement (Registration No. 33-44193)).

(4.2)	First Supplemental Indenture, dated as of December 1, 1991, by and between Northern Indiana Public Service Company and Manufacturers Hanover Trust Company, as Trustee (incorporated by reference to Exhibit 4.1 to the NIPSCO Registration Statement (Registration No. 33-63870)).
(4.3)	Indenture Agreement, dated as of February 14, 1997, by and between NIPSCO Industries, Inc., NIPSCO Capital Markets, Inc. and Chase Manhattan Bank as trustee (incorporated by reference to Exhibit 4.1 to the NIPSCO Industries, Inc. Registration Statement (Registration No. 333-22347)).
(4.4)	Second Supplemental Indenture, dated as of November 1, 2000, by and among NiSource Capital Markets, Inc., NiSource Inc., New NiSource Inc., and The Chase Manhattan Bank, as trustee (incorporated by reference to Exhibit 4.45 to the NiSource Inc. Form 10-K for the period ended December 31, 2000).
(4.5)	Indenture, dated November 14, 2000, among NiSource Finance Corp., NiSource Inc., as guarantor, and The Chase Manhattan Bank, as Trustee (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form S-3, dated November 17, 2000 (Registration No. 333-49330)).
(4.6)	Form of 3.490% Notes due 2027 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on May 17, 2017).
(4.7)	Form of 4.375% Notes due 2047 (incorporated by reference to Exhibit 4.2 to the NiSource Inc. Form 8-K filed on May 17, 2017).
(4.8)	Form of 3.950% Notes due 2048 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on September 8, 2017).
(4.9)	Form of 2.650% Notes due 2022 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on November 14, 2017).
(4.10)	Second Supplemental Indenture, dated as of November 30, 2017, between NiSource Inc. and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.4 to Post-Effective Amendment No. 1 to Form S-3 filed November 30, 2017 (Registration No. 333-214360)).
(4.11)	Third Supplemental Indenture, dated as of November 30, 2017, between NiSource Inc. and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.2 to the NiSource Inc. Form 8-K filed on December 1, 2017).
(4.12)	Second Supplemental Indenture, dated as of February 12, 2018, between Northern Indiana Public Service Company and The Bank of New York Mellon, solely as successor trustee under the Indenture dated as of March 1, 1988 between the Company and Manufacturers Hanover Trust Company, as original trustee. (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 10-Q filed on May 2, 2018).
(4.13)	Third Supplemental Indenture, dated as of June 11, 2018, by and between NiSource Inc. and The Bank of New York Mellon, as trustee (including form of 3.650% Notes due 2023) (incorporated by reference to Exhibit 4.1 of the NiSource Inc. Form 8-K filed on June 12, 2018).
(4.14)	Deposit Agreement, dated as of December 5, 2018, among NiSource, Inc., Computershare Inc. and Computershare Trust Company, N.A., acting jointly as depositary, and the holders from time to time of the depositary receipts described therein (incorporated by reference to Exhibit 4.1 of the NiSource Inc. Form 8-K filed on December 6, 2018).
(4.15)	Form of Depositary Receipt (incorporated by reference to Exhibit 4.1 of the NiSource Inc. Form 8-K filed on December 6, 2018).
(4.16)	Amended and Restated Deposit Agreement, dated as of December 27, 2018, among NiSource, Inc., Computershare Inc. and Computershare Trust Company, N.A., acting jointly as depositary, and the holders from time to time of the depositary receipts described therein (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on December 27, 2018).
(4.17)	Form of Depositary Receipt (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on December 27, 2018).
(10.1)	2010 Omnibus Incentive Plan (incorporated by reference to Exhibit B to the NiSource Inc. Definitive Proxy Statement to Stockholders for the Annual Meeting held on May 11, 2010, filed on April 2, 2010).*

(10.2) First Amendment to the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.2 to the NiSource Inc. Form 10-K filed on February 18, 2014.)*

(10.3) 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit C to the NiSource Inc. Definitive Proxy Statement to Stockholders for the Annual Meeting held on May 12, 2015, filed on April 7, 2015).*

(10.4)	Second Amendment to the NiSource Inc. 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 8-K filed October 23, 2015.)*
(10.5)	Form of Performance Share Award Agreement under the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 10-Q filed on April 30, 2014.)*
(10.6)	Form of Amended and Restated 2013 Performance Share Agreement effective on implementation of the spin-off on July 1, 2015, (under the 2010 Omnibus Incentive Plan)(incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 10-Q filed on November 3, 2015).*
(10.7)	Form of Amended and Restated 2014 Performance Share Agreement effective on the implementation of the spin-off on July 1, 2015, (under the 2010 Omnibus Incentive Plan)(incorporated by reference to Exhibit 10.2 to the NiSource Inc. Form 10-Q filed on November 3, 2015).*
(10.8)	Form of Amendment to Restricted Stock Unit Award Agreement related to Vested but Unpaid NiSource Restricted Stock Unit Awards for Nonemployee Directors of NiSource entered into as of July 13, 2015 (incorporated by reference to Exhibit 10.3 to the NiSource Inc. Form 10-Q filed on November 3, 2015).*
(10.9)	NiSource Inc. Nonemployee Director Retirement Plan, as amended and restated effective May 13, 2008 (incorporated by reference to Exhibit 10.2 to the NiSource Inc. Form 10-K filed on February 27, 2009).*
(10.10)	Supplemental Life Insurance Plan effective January 1, 1991, as amended, (incorporated by reference to Exhibit 2 to the NIPSCO Industries, Inc. Form 8-K filed on March 25, 1992).*
(10.11)	Form of Change in Control and Termination Agreement (incorporated by reference to Exhibit 99.1 to the NiSource Inc. Form 8-K filed January 6, 2014).*
(10.12)	Revised Form of Change in Control and Termination Agreement (incorporated by reference to Exhibit 10.2 to the NiSource Inc. Form 8-K filed on October 23, 2015.)*
(10.13)	Form of Restricted Stock Agreement under the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.18 to the NiSource Inc. Form 10-K filed on February 28, 2011).*
(10.14)	Form of Restricted Stock Unit Award Agreement for Non-employee directors under the Non-employee Director Stock Incentive Plan (incorporated by reference to Exhibit 10.19 to the NiSource Inc. Form 10-K filed on February 28, 2011).*
(10.15)	Form of Restricted Stock Unit Award Agreement for Nonemployee Directors under the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.1 to NiSource Inc. Form 10-Q filed on August 2, 2011).*
(10.16)	Form of Performance Share Award Agreement under the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.3 to the NiSource Inc. Form 10-Q filed on May 3, 2016).*
(10.17)	Form of Restricted Stock Unit Award Agreement under the 2010 Omnibus Incentive Plan.* (incorporated by reference to Exhibit 10.17 to the NiSource Inc. Form 10-K filed on February 22, 2017)
(10.18)	Form of Restricted Stock Unit Award Agreement for Nonemployee Directors under the 2010 Omnibus Incentive Plan. (incorporated by reference to Exhibit 10.18 to the NiSource Inc. Form 10-K filed on February 22, 2017) *
(10.19)	Amended and Restated NiSource Inc. Supplemental Executive Retirement Plan effective May 13, 2011 (incorporated by reference to Exhibit 10.3 to NiSource Inc. Form 10-Q filed on October 28, 2011).*
(10.20)	Amended and Restated Pension Restoration Plan for NiSource Inc. and Affiliates effective May 13, 2011 (incorporated by reference to Exhibit 10.4 to NiSource Inc. Form 10-Q filed on October 28, 2011).*
(10.21)	Amended Restated Savings Restoration Plan for NiSource Inc. and Affiliates effective October 22, 2012 (incorporated by reference to Exhibit 10.20 to the NiSource Inc. Form 10-K filed on February 19, 2013).*
(10.22)	Amended and Restated NiSource Inc. Executive Deferred Compensation Plan effective November 1, 2012 (incorporated by reference to Exhibit 10.21 to the NiSource Inc. Form 10-K filed on February 19, 2013).*
(10.23)	NiSource Inc. Executive Severance Policy, as amended and restated, effective January 1, 2015 (incorporated by reference to Exhibit 10.21 to the NiSource Inc. Form 10-K filed on February 18, 2015).*

(10.24)	Fourth Amended and Restated Revolving Credit Agreement, dated as of November 28, 2016, among NiSource Finance Corp., as Borrower, NiSource Inc., the Lenders party thereto, Barclays Bank PLC, as Administrative Agent, JPMorgan Chase Bank, N.A. and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Co-Syndication Agents, Citibank, N.A., Credit Suisse AG, Cayman Islands Branch and Wells Fargo Bank, National Association, as Co-Documentation Agents, and Barclays Bank PLC, JPMorgan Chase Bank, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd., Credit Suisse Securities (USA) LLC, Citigroup Global Markets, Inc. and Wells Fargo Securities, LLC, as Joint Lead Arrangers and Joint Bookrunners (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 8-K filed on November 28, 2016).
(10.25)	Note Purchase Agreement, dated as of August 23, 2005, by and among NiSource Finance Corp., as issuer, NiSource Inc., as guarantor, and the purchasers named therein (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Current Report on Form 8-K filed on August 26, 2005).
(10.26)	Amendment No. 1, dated as of November 10, 2008, to the Note Purchase Agreement by and among NiSource Finance Corp., as issuer, NiSource Inc., as guarantor, and the purchasers whose names appear on the signature page thereto (incorporated by reference to Exhibit 10.30 to the NiSource Inc. Form 10-K filed on February 27, 2009).
(10.27)	Term Loan Agreement, dated as of March 31, 2016, by and among NiSource Finance Corp., as Borrower, NiSource Inc., as Guarantor, the Lenders party thereto, and PNC Bank, National Association, as Administrative Agent, JP Morgan Chase Bank, N.A., as Syndication Agent, and Mizuho Bank, Ltd., as Documentation Agent (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 10-Q filed on May 3, 2016).
(10.28)	Letter Agreement, dated as of March 17, 2015, by and between NiSource Inc. and Donald Brown. (incorporated by reference Exhibit 10.1 to the NiSource Inc. Form 10-Q filed on April 30, 2015).*
(10.29)	Letter Agreement, dated as of February 23, 2016, by and between NiSource Inc. and Pablo A. Vegas. (incorporated by reference Exhibit 10.29 to the NiSource Inc. Form 10-K filed on February 22, 2017).*
(10.30)	Tax Allocation Agreement, dated as of June 30, 2015, by and between NiSource Inc. and Columbia Pipeline Group, Inc. (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 8-K filed on July 2, 2015).
(10.31)	Employee Matters Agreement, dated as of June 30, 2015, by and between NiSource Inc. and Columbia Pipeline Group, Inc. (incorporated by reference to Exhibit 10.2 of the NiSource Inc. Form 8-K filed on July 2, 2015).
(10.32)	Form of Change in Control and Termination Agreement (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 10-Q filed on August 2, 2017).
(10.33)	Form of Performance Share Award Agreement under the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.33 to the NiSource Form 10-K filed on February 20, 2018).*
(10.34)	Form of Restricted Stock Unit Award Agreement under the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.34 to the NiSource Form 10-K filed on February 20, 2018).*
(10.35)	Term Loan Agreement dated as of April 18, 2018 among NiSource Inc., as borrower, the lenders party thereto and MUFG Bank, Ltd., as administrative agent and as sole lead arranger and sole bookrunner (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 8-K filed on April 19, 2018).
(10.36)	Common Stock Subscription Agreement, dated as of May 2, 2018, by and among NiSource Inc. and the purchasers named therein (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 8-K filed on May 2, 2018).
(10.37)	Registration Rights Agreement, dated as of May 2, 2018, by and among NiSource Inc. and the purchasers named therein (incorporated by reference to Exhibit 10.2 of the NiSource Inc. Form 8-K filed on May 2, 2018).
(10.38)	Purchase Agreement, dated as of June 6, 2018, by and among NiSource Inc. and Credit Suisse Securities (USA) LLC, J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC and MUFG Securities Americas Inc., as representatives, relating to the 5.650% Series A Preferred Stock (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 8-K filed on June 12, 2018).
(10.39)	Purchase Agreement, dated as of June 6, 2018, by and among NiSource Inc. and Credit Suisse Securities (USA) LLC, J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC and MUFG Securities Americas Inc., as representatives, relating to the 3.650% Notes due 2023 (incorporated by reference to Exhibit 10.2 of the NiSource Inc. Form 8-K filed on June 12, 2018).

(10.40) Registration Rights Agreement, dated as of June 11, 2018, by and among NiSource Inc. and Credit Suisse Securities (USA) LLC, J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC and MUFG Securities Americas Inc., as representatives, relating to the 5.650% Series A Preferred Stock (incorporated by reference to Exhibit 10.3 of the NiSource Inc. Form 8-K filed on June 12, 2018).

(10.41)	Registration Rights Agreement, dated as of June 11, 2018, by and among NiSource Inc. and Credit Suisse Securities (USA) LLC, J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC and MUFG Securities Americas Inc., as representatives, relating to the 3.650% Notes due 2023 (incorporated by reference to Exhibit 10.4 of the NiSource Inc. Form 8-K filed on June 12, 2018).
(10.42)	Amended and Restated NiSource Inc. Supplemental Executive Retirement Plan effective August 10, 2017 (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 10-Q filed on November 1, 2018).
(10.43)	Amended and Restated Pension Restoration Plan for NiSource Inc. and Affiliates effective August 10, 2017 (incorporated by reference to Exhibit 10.2 of the NiSource Inc. Form 10-Q filed on November 1, 2018).
(10.44)	Amended Restated Savings Restoration Plan for NiSource Inc. and Affiliates effective August 10, 2017 (incorporated by reference to Exhibit 10.3 of the NiSource Inc. Form 10-Q filed on November 1, 2018).
(10.45)	Form of 2019 Performance Share Award Agreement under the 2010 Omnibus Incentive Plan.* **
(21)	List of Subsidiaries.**
(23)	Consent of Deloitte & Touche LLP.**
(31.1)	Certification of Chief Executive Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.**
(31.2)	Certification of Chief Financial Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.**
(32.1)	Certification of Chief Executive Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).**
(32.2)	Certification of Chief Financial Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).**
(101.INS)	XBRL Instance Document.**
(101.SCH)	XBRL Schema Document.**
(101.CAL)	XBRL Calculation Linkbase Document.**
(101.LAB)	XBRL Labels Linkbase Document.**
(101.PRE)	XBRL Presentation Linkbase Document.**
(101.DEF)	XBRL Definition Linkbase Document.**

* Management contract or compensatory plan or arrangement of NiSource Inc.

** Exhibit filed herewith.

References made to NIPSCO filings can be found at Commission File Number 001-04125. References made to NiSource Inc. filings made prior to November 1, 2000 can be found at Commission File Number 001-09779.

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, hereunto duly authorized.

NiSource Inc.
(Registrant)

Date: February 20, 2019

By: /s/ JOSEPH HAMROCK
Joseph Hamrock
President, Chief Executive Officer and Director
(Principal Executive Officer)

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.

/s/ JOSEPH HAMROCK Joseph Hamrock	President, Chief Executive Officer and Director (Principal Executive Officer)	Date: February 20, 2019
/s/ DONALD E. BROWN Donald E. Brown	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	Date: February 20, 2019
/s/ JOSEPH W. MULPAS Joseph W. Mulpas	Vice President and Chief Accounting Officer (Principal Accounting Officer)	Date: February 20, 2019
/s/ RICHARD L. THOMPSON Richard L. Thompson	Chairman and Director	Date: February 20, 2019
/s/ PETER A. ALTABEF Peter A. Altabef	Director	Date: February 20, 2019
/s/ THEODORE H. BUNTING, JR. Theodore H. Bunting	Director	Date: February 20, 2019
/s/ ERIC L. BUTLER Eric L. Butler	Director	Date: February 20, 2019
/s/ ARISTIDES S. CANDRIS Aristides S. Candris	Director	Date: February 20, 2019
/s/ WAYNE S. DEVEYDT Wayne S. DeVeydt	Director	Date: February 20, 2019
/s/ DEBORAH A. HENRETTA Deborah A. Henretta	Director	Date: February 20, 2019
/s/ MICHAEL E. JESANIS Michael E. Jesanis	Director	Date: February 20, 2019
/s/ KEVIN T. KABAT Kevin T. Kabat	Director	Date: February 20, 2019
/s/ CAROLYN Y. WOO Carolyn Y. Woo	Director	Date: February 20, 2019

Exhibit 10.45

NiSource Inc.

2010 Omnibus Incentive Plan

Performance Share Award Agreement

This Performance Share Award Agreement (the "Agreement") is made and entered into as of _______________ (the "Grant Date"), by and between NiSource Inc., a Delaware corporation (the "Company"), and __________________ an Employee of the Company (the "Grantee"), pursuant to the terms of the NiSource Inc. 2010 Omnibus Incentive Plan, as amended (the "Plan"). Any term capitalized but not defined in this Agreement shall have the meaning set forth in the Plan.

Section 1. Performance Share Award. The Company hereby grants to the Grantee, on the terms and conditions hereinafter set forth, a target award of ______________Performance Shares (the "Performance Shares"). The Performance Shares shall be represented by a bookkeeping entry with respect to the Grantee (the "Performance Share Account") of the Company, and each Performance Share shall be settled with one Share, to the extent provided under this Agreement and the Plan. This Agreement and the award shall be null and void unless the Grantee accepts this Agreement electronically within the Grantee's stock plan account with the Company's stock plan administrator according to the procedures then in effect.

Section 2. Performance-Based Vesting Conditions.

(a) General. Subject to the remainder of this Agreement, the Performance Shares shall vest pursuant to the terms of this Agreement and the Plan based on the achievement of the performance goals set forth in this Section 2 over the performance period beginning on _________________ and ending on _________________ (the "Performance Period"), provided (i) that that the Grantee remains in continuous Service through _________________ (the "Vesting Date") and (ii) the Company achieves the threshold cumulative NOEPS goal set forth in Section 2(b). Attainment of the performance goals shall be determined and certified by the Compensation Committee of the Board of Directors of the Company (the "Committee") prior to the settlement of the Performance Shares.

(b) Financial Performance Goal. Subject to the terms of this Agreement and the Plan, _________________shall be eligible to vest based on the Company's achievement of cumulative NOEPS during the Performance Period, as follows:

Performance Level(1)	Cumulative NOEPS	Percentage of Performance Shares that Shall Vest(2)
Threshold	$________	____________
Target	$________	____________
Maximum	$_______and above	____________

(1) The vesting percentage for performance between performance levels shall be determined based on linear interpolation.

(2) The number of Performance Shares that shall vest based on the Company's cumulative NOEPS performance shall be subject to a performance modifier of +/- 25% based on the Company's RTSR over the Performance Period, with such Performance Shares (i) increasing by 25% if the Company's RTSR is in the top quartile of the TSR Peer Group, (ii) decreasing by 25% if the Company's RTSR is in the bottom quartile of the TSR Peer Group, and (iii) remaining the same if the Company's RTSR is in the second or third quartiles of the TSR Peer Group. No other adjustment shall be made based on the Company's RTSR.

(c) Customer Framework Performance Goals. Subject to the terms of this Agreement and the Plan, _________________shall be eligible to vest based on the achievement of the Customer Framework Goals set forth below, with each goal equally weighted:

Performance Measure	Goal(1)
National Safety Council Barometer Survey	_________________
JD Power Gas and Electric Utility Residential Customer Satisfaction Studies	_________________
Operations and Maintenance Financial Plan	_________________
Organizational Health Index	_________________
Greenhouse Gas Emissions	_________________

(1) If the Company fails to achieve the applicable performance goal, then the Performance Shares allocated to such performance goal shall not be eligible to vest.

(d) Definitions.

(i) "cumulative NOEPS" means the Company's cumulative net operating earnings per share performance as certified by the Committee following the Performance Period.

(ii) "RTSR" means the annualized growth in the dividends and share price of a Share, calculated using a 20 day trading average of the Company's closing price beginning on __________________ and ending ________________ compared to the TSR performance of the TSR Peer Group. The starting and ending share prices for the computation of RTSR will equal the average closing price of each company's common stock over the 20 trading days immediately preceding the first and last day of the performance period.

(iii) "TSR Peer Group" means the peer group of companies determined by the Committee at its meeting on _________________.

Section 3. Termination of Employment.

(a) Termination of Service Prior to Vesting Date. Except as set forth below, if the Grantee's Service is terminated for any reason prior to the Vesting Date, then the Grantee shall forfeit the Performance Shares credited to the Grantee's Performance Share Account.

(b) Retirement, Disability or Death.

(i) Notwithstanding the foregoing, in the event that the Grantee's Service terminates prior to the Vesting Date and on or within 12 months prior to the end of the Performance Period as a result of the Grantee's (i) Retirement, (ii) Disability; or (iii) death, then the Grantee (or the Grantee's beneficiary or estate in the case of the Grantee's death) shall vest in a pro rata portion of the Performance Shares, based on the actual performance results for the Performance Period. Such pro rata portion of the Performance Shares shall be determined by multiplying the number of Performance Shares earned based on actual performance by a fraction, where the numerator shall equal the number of calendar months (including partial calendar months) that have elapsed from the Grant Date through the date of the Grantee's termination of Service, and the denominator shall be the number of calendar months (including partial calendar months) that have elapsed between the Grant Date and __________________.

(ii) If the Grantee terminates Service due to death prior to the Vesting Date and with more than 12 months remaining in the Performance Period, then the Grantee's beneficiary or estate shall vest, on the date of termination, in a pro rata portion of the target Performance

Shares. Such pro rata portion of the Performance Shares shall be determined by multiplying the number of target Performance Shares by a fraction, where the numerator shall equal the number of calendar months (including partial calendar months) that have elapsed from the Grant Date through the date of the Grantee's termination of Service, and the denominator shall be the number of calendar months (including partial calendar months) that have elapsed between the Grant Date and _______________.

(iii) "Retirement" means the Grantee's termination from Service at or after attainment of age 55 and completing at least ten years of service (within the meaning of the Company's tax-qualified pension plan, as in effect on the Grant Date, regardless of whether the Grantee is eligible for such plan).

(c) Change in Control. Notwithstanding the foregoing provisions, in the event of a Change in Control, the Performance Shares under this Agreement shall be subject to Article XVI of the Plan. In the event of any conflict between Article XVI of the Plan and this Agreement, Article XVI shall control. Notwithstanding any other agreement between the Company and the Grantee, the "Good Reason" definition set forth in Section 16.1 of the Plan shall govern this award.

Section 4. Delivery of Shares. Subject to the terms of this Agreement and except as otherwise provided for herein, the Company shall convert the Performance Shares in the Grantee's Performance Share Account into Shares and issue or deliver the total number of Shares due to the Grantee as soon as administratively practicable after the Vesting Date (but in no event later than _________________) or, if earlier, within 30 days following the Grantee's death in accordance with Section 3(b)(ii), Grantee's termination of Service without Cause or due to Good Reason in accordance with Section 16.1(a) of the Plan or a Change in Control in accordance with Section 16.1(b) of the Plan. The delivery of the Shares shall be subject to payment of the applicable withholding tax liability and the forfeiture provisions of this Agreement. If the Grantee dies before the Company has issued or distributed the vested Performance Shares, the Company shall transfer any Shares with respect to the vested Performance Shares in accordance with the Grantee's written beneficiary designation or to the Grantee's estate if no written beneficiary designation is provided. The issuance or deliver of the Shares hereunder shall be evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company. The Company shall pay all original issue or transfer taxes and all fees and expenses incident to such issuance or delivery, except as otherwise provided in Section 5.

Section 5. Withholding of Taxes. As a condition precedent to the delivery to Grantee of any Shares upon vesting of the Performance Shares, Grantee shall, upon request by the Company, pay to the Company such amount of cash as the Company may be required, under all applicable federal, state, local or other laws or regulations, to withhold and pay over as income or other withholding taxes (the "Required Tax Payments") with respect to the Performance Shares. If Grantee shall fail to advance the Required Tax Payments after request by the Company, the Company may, in its discretion, deduct any Required Tax Payments from any amount then or thereafter payable by the Company to Grantee or withhold Shares. Grantee may elect to satisfy his or her obligation to advance the Required Tax Payments by any of the following means: (a) a cash payment to the Company; (b) delivery to the Company (either actual delivery or by attestation procedures established by the Company) of previously owned whole Shares having a Fair Market Value, determined as of the date the obligation to withhold or pay taxes first arises in connection with the Performance Shares (the "Tax Date"), equal to the Required Tax Payments; (c) authorizing the Company to withhold from the Shares otherwise to be delivered to Grantee upon the vesting of the Performance Shares, a number of whole Shares having a Fair Market Value, determined as of the Tax Date, equal to the Required Tax Payments; or (d) any combination of (a), (b) and (c). Shares to be delivered or withheld may not have a Fair Market Value in excess of the minimum amount of the Required Tax Payments. Any fraction of a Share which would be required to satisfy such an obligation shall be disregarded and the remaining amount due shall be paid in cash by Grantee. No Shares shall be delivered until the Required Tax Payments have been satisfied in full.

Section 6. Compliance with Applicable Law. Notwithstanding anything contained herein to the contrary, the Company's obligation to issue or deliver certificates evidencing the Performance Shares shall be subject to all applicable laws, rules and regulations, and to such approvals by any governmental agencies or national securities exchanges as may be required. The delivery of all or any Shares that relate to the Performance Shares shall be effective only at such time that the issuance of such Shares shall not violate any state or federal securities or other laws. The Company is under no obligation to effect any registration of Shares under the Securities Act of 1933 or to effect any state registration or qualification of the Shares that may be issued under this Agreement. Subject to Section 409A of the Code (the "Section 409A"), the Company may, in its sole discretion, delay the delivery of Shares or place restrictive legends on Shares in order to ensure that the issuance of any Shares shall be in compliance with federal or state securities laws and the rules of any exchange upon which the Company's Shares are traded. If the Company delays the delivery of Shares in order to ensure compliance with any state or federal securities or other laws, the Company shall deliver the Shares at the earliest date at which the Company reasonably believes that such delivery shall not cause such violation, or at such later date that may be permitted under Section 409A.

Section 7. Restriction on Transferability. Except as otherwise provided under the Plan, until the Performance Shares have vested under this Agreement, the Performance Shares granted herein and the rights and privileges conferred hereby may not be sold, transferred, pledged, assigned, or otherwise alienated or hypothecated (by operation of law or otherwise), other than by will or the laws of descent and distribution. Any attempted transfer in violation of the provisions of this paragraph shall be void, and the purported transferee shall obtain no rights with respect to such Performance Shares.

Section 8. Grantee's Rights Unsecured. The right of the Grantee or his or her beneficiary to receive a distribution hereunder shall be an unsecured claim against the general assets of the Company, and neither the Grantee nor his or her beneficiary shall have any rights in or against any amounts credited to the Grantee's Performance Share Account, any Shares or any other specific assets of the Company. All amounts credited to the Grantee's Performance Share Account shall constitute general assets of the Company and may be disposed of by the Company at such time and for such purposes as it may deem appropriate.

Section 9. No Rights as Stockholder or Employee. The Grantee shall not have any privileges of a stockholder of the Company (including, without limitation, any voting rights or rights to receive dividends) with respect to the Performance Shares subject to this Agreement. Furthermore, nothing in this Agreement shall confer upon the Grantee any right to continue as an Employee of the Company or any Affiliate or to interfere in any way with the right of the Company or any Affiliate to terminate the Grantee's Service at any time.

Section 10. Adjustments. If at any time while the award is outstanding, the number of outstanding Performance Shares is changed by reason of a reorganization, recapitalization, stock split or any of the other events described in the Plan, the number and kind of Performance Shares and the performance goals, as applicable, shall be adjusted in accordance with the provisions of the Plan.

Section 11. Notices. Any notice hereunder by the Grantee shall be given to the Company in writing, and such notice shall be deemed duly given only upon receipt thereof at the following address: Corporate Secretary, NiSource Inc., 801 East 86th Avenue, Merrillville, IN 46410-6271 (or at such other address as the Company may designate by notice to the Grantee). Any notice hereunder by the Company shall be given to the Grantee in writing, and such notice shall be deemed duly given only upon receipt thereof at such address as the Grantee may have on file with the Company.

Section 12. Administration. The administration of this Agreement, including the interpretation and amendment or termination of this Agreement, shall be performed in accordance with the Plan. All determinations and decisions made by the Committee, the Board, or any delegate of the Committee as to the provisions of this Agreement shall be conclusive, final, and binding on all persons. Notwithstanding the foregoing, if subsequent guidance is issued under Section 409A that would impose additional taxes, penalties, or interest to either the Company or the Grantee, the Company may administer this Agreement in accordance with such guidance and amend this Agreement without the consent of the Grantee to the extent such actions, in the reasonable judgment of the Company, are considered necessary to avoid the imposition of such additional taxes, penalties, or interest.

Section 13. Governing Law. This Agreement shall be construed and enforced in accordance with the laws of the State of Indiana, without giving effect to the choice of law principles thereof.

Section 14. Entire Agreement; Agreement Subject to Plan. This Agreement and the Plan contain all of the terms and conditions with respect to the subject matter hereof and supersede any previous agreements, written or oral, relating to the subject matter hereof. This Agreement is subject to the provisions of the Plan and shall be interpreted in accordance therewith. In the event that the provisions of this Agreement and the Plan conflict, the Plan shall control. The Grantee hereby acknowledges receipt of a copy of the Plan.

Section 15. Section 409A Compliance. This Agreement and the Performance Shares granted hereunder are intended to be exempt from Section 409A to the maximum extent possible, and shall be interpreted and construed accordingly.

[SIGNATURE PAGE TO FOLLOW]

IN WITNESS WHEREOF, the Company has caused the Performance Shares subject to this Agreement to be granted, and the Grantee has accepted the Performance Shares subject to the terms of the Agreement, as of the date first above written.

NiSource Inc.

____
By: __________________
Its: __________________

GRANTEE

By: ____
____

Exhibit 21

SUBSIDIARIES OF NISOURCE

as of December 31, 2018

Segment/Subsidiary	
GAS DISTRIBUTION OPERATIONS	**State of Incorporation**
Bay State Gas Company d/b/a Columbia Gas of Massachusetts	Massachusetts
Central Kentucky Transmission Company	Delaware
Columbia Gas of Kentucky, Inc.	Kentucky
Columbia Gas of Maryland, Inc.	Delaware
Columbia Gas of Ohio, Inc.	Ohio
Columbia Gas of Pennsylvania, Inc.	Pennsylvania
Columbia Gas of Virginia, Inc.	Virginia
NiSource Gas Distribution Group, Inc.	Delaware
ELECTRIC OPERATIONS	
Northern Indiana Public Service Company LLC*	Indiana
CORPORATE AND OTHER OPERATIONS	
Columbia Gas of Ohio Receivables Corporation	Delaware
Columbia Gas of Pennsylvania Receivables Corporation	Delaware
NIPSCO Accounts Receivable Corporation	Indiana
NiSource Corporate Group, LLC	Delaware
NiSource Corporate Services Company	Delaware
NiSource Development Company, Inc.	Indiana
NiSource Energy Technologies, Inc.	Indiana
NiSource Strategic Sourcing Inc.	Ohio
NiSource Insurance Corporation, Inc.	Utah
Lake Erie Land Company	Indiana
RoseWater Wind Generation LLC	Indiana
NiSource Retail Services, Inc.	Delaware (Inactive)
EnergyUSA-TPC, Inc.	Indiana (Inactive)

* Reported under Gas Distribution Operations and Electric Operations.

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-107743, 333-166888, 333-170706, 333-204168 and 333-228102 on Form S-8, 333-214360 on Form S-3, 333-228791, 333-228790 and 333-228791 on Form S-4 of our reports dated February 20, 2019, relating to the consolidated financial statements and financial statement schedule of NiSource Inc. and subsidiaries (the "Company") and the effectiveness of the Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of NiSource Inc. for the year ended December 31, 2018.

/s/ DELOITTE & TOUCHE LLP
Columbus, Ohio
February 20, 2019

Exhibit 31.1

Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Joseph Hamrock, certify that:

1. I have reviewed this Annual Report on Form 10-K of NiSource Inc.;

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(s) 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, 2019	By:	/s/ Joseph Hamrock
			Joseph Hamrock
			President and Chief Executive Officer

Exhibit 31.2

Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Donald E. Brown, certify that:

1. I have reviewed this Annual Report on Form 10-K of NiSource Inc.;

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(s) 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, 2019

By: /s/ Donald E. Brown
Donald E. Brown
Executive Vice President and Chief Financial Officer

Exhibit 32.1

Certification Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of NiSource Inc. (the "Company") on Form 10-K for the year ending December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Joseph Hamrock, Chief Executive Officer of the Company, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report 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 the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ Joseph Hamrock

Joseph Hamrock
President and Chief Executive Officer

Date: February 20, 2019

Exhibit 32.2

Certification Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of NiSource Inc. (the "Company") on Form 10-K for the year ending December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Donald E. Brown, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report 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 the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ Donald E. Brown

Donald E. Brown
Executive Vice President and Chief Financial Officer

Date: February 20, 2019