VECTREN CORP
Form 10-K
February 23, 2017

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2016
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: 1-15467

VECTREN CORPORATION

(Exact name of registrant as specified in its charter)

INDIANA (State or other jurisdiction of incorporation or organization)	35-2086905 (IRS Employer Identification No.)
One Vectren Square (Address of principal executive offices)	47708 (Zip Code)

Registrant's telephone number, including area code: 812-491-4000

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

Title of each class	Name of each exchange on which registered
Common – Without Par	New York Stock Exchange

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 ý No ¨

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

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 ý No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of 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. ý

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ý	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No ý

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of June 30, 2016, was $4,356,496,757.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

Common Stock - Without Par Value	82,922,412	January 31, 2017
Class	Number of Shares	Date

Documents Incorporated by Reference

Certain information in the Company's definitive Proxy Statement for the 2017 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission pursuant to Regulation 14A, not later than 120 days after the end of the fiscal year, is incorporated by reference in Part III of this Form 10-K.

Definitions

AFUDC: allowance for funds used during construction	IRP: Integrated Resource Plan
ASC: Accounting Standards Codification	kV: Kilovolt
ASU: Accounting Standards Update	MDth / MMDth: thousands / millions of dekatherms
BTU / MMBTU: British thermal units / millions of BTU	MISO: Midcontinent Independent System Operator
DOT: Department of Transportation	MCF / BCF: thousands / billions of cubic feet
EPA: Environmental Protection Agency	MW: megawatts
FAC: Fuel Adjustment Clause	MWh / GWh: megawatt hours / thousands of megawatt hours (gigawatt hours)
FASB: Financial Accounting Standards Board	NERC: North American Electric Reliability Corporation
FERC: Federal Energy Regulatory Commission	OCC: Ohio Office of the Consumer Counselor
GAAP: Generally Accepted Accounting Principles	OUCC: Indiana Office of the Utility Consumer Counselor
GCA: Gas Cost Adjustment	PHMSA: Pipeline and Hazardous Materials Safety Administration
IURC: Indiana Utility Regulatory Commission	PUCO: Public Utilities Commission of Ohio
IRC: Internal Revenue Code	Throughput: combined gas sales and gas transportation volumes
IDEM: Indiana Department of Environmental Management	XBRL: eXtensible Business Reporting Language

Access to Information

Vectren Corporation makes available all SEC filings and recent annual reports free of charge through its website at www.vectren.com as soon as reasonably practicable after electronically filing or furnishing the reports to the SEC, or by request, directed to Investor Relations at the mailing address, phone number, or email address that follows:

Mailing Address: One Vectren Square Evansville, Indiana 47708	Phone Number: (812) 491-4000	Investor Relations Contact: David E. Parker Director, Investor Relations vvcir@vectren.com

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PART I

ITEM 1. BUSINESS

Description of the Business

Vectren Corporation (the Company or Vectren), an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana. The Company's wholly owned subsidiary, Vectren Utility Holdings, Inc. (Utility Holdings or VUHI), serves as the intermediate holding company for three public utilities: Indiana Gas Company, Inc. (Indiana Gas or Vectren Energy Delivery of Indiana - North), Southern Indiana Gas and Electric Company (SIGECO or Vectren Energy Delivery of Indiana - South), and Vectren Energy Delivery of Ohio, Inc. (VEDO). Utility Holdings also has other assets that provide information technology and other services to the three utilities. Utility Holdings' consolidated operations are collectively referred to as the Utility Group. Both Vectren and Utility Holdings are holding companies as defined by the Energy Policy Act of 2005. Vectren was incorporated under the laws of Indiana on June 10, 1999.

Indiana Gas provides energy delivery services to approximately 587,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 144,000 electric customers and approximately 111,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to approximately 316,000 natural gas customers located near Dayton in west-central Ohio.

The Company, through Vectren Enterprises, Inc. (Enterprises), is involved in nonutility activities in two primary business areas: Infrastructure Services and Energy Services. Infrastructure Services provides underground pipeline construction and repair services. Energy Services provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects. Prior to August 29, 2014, the Company had activities in a coal mining business through Vectren Fuels, Inc. (Vectren Fuels). Results in the financial statements include the results of Coal Mining through the date of sale of August 29, 2014, when the Company exited the coal mining business. Enterprises also has other legacy businesses that have investments in energy-related opportunities and services, among other investments. All of the above is collectively referred to as the Nonutility Group. Enterprises supports the Company's regulated utilities by providing infrastructure services.

Narrative Description of the Business

The Company segregates its operations into three groups: the Utility Group, the Nonutility Group, and Corporate and Other. At December 31, 2016, the Company had $5.8 billion in total assets, with $5.0 billion attributed to the Utility Group, and $0.8 billion attributed to the Nonutility Group. Net income for the year ended December 31, 2016, was $211.6 million, or $2.55 per share of common stock, with net income of $173.6 million attributed to the Utility Group, $36.9 million attributed to the Nonutility Group, and $1.1 million attributed to Corporate and Other. Net income for the year ended December 31, 2015, was $197.3 million, or $2.39 per share of common stock. For further information regarding the activities and assets of operating segments within these Groups, refer to Note 22 in the Company's Consolidated Financial Statements included in Item 8. Following is a more detailed description of the Utility Group and Nonutility Group.

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Utility Group

The Utility Group consists of the Company's regulated operations and other operations that provide information technology and other support services to those regulated operations. The Company segregates its regulated operations into a Gas Utility Services operating segment and an Electric Utility Services operating segment. The Gas Utility Services segment includes the operations of Indiana Gas, VEDO, and SIGECO's natural gas distribution business and provides natural gas distribution and transportation services to nearly two-thirds of Indiana and about 20 percent of Ohio, primarily in the west-central area. The Electric Utility Services segment includes the operations of SIGECO's electric transmission and distribution services, which provides electric transmission and distribution services to southwestern Indiana, and includes its power generating and wholesale power operations. In total, these regulated operations supply natural gas and electricity to over one million customers. Following is a more detailed description of the Utility Group's Gas Utility and Electric Utility operating segments.

Gas Utility Services

At December 31, 2016, the Company supplied natural gas service to approximately 1,028,300 Indiana and Ohio customers, including 940,500 residential, 86,100 commercial, and 1,700 industrial and other contract customers. Average gas utility customers served were approximately 1,014,000 in 2016; 1,004,800 in 2015; and 998,200 in 2014.

The Company's service area contains diversified manufacturing and agriculture-related enterprises. The principal industries served include automotive assembly, parts and accessories; feed, flour and grain processing; metal castings, plastic products; gypsum products; electrical equipment, metal specialties, glass and steel finishing; pharmaceutical and nutritional products; gasoline and oil products; ethanol; and coal mining. The largest Indiana communities served are Evansville, Bloomington, Terre Haute, suburban areas surrounding Indianapolis and Indiana counties near Louisville, Kentucky. The largest community served outside of Indiana is Dayton, Ohio.

Revenues

The Company receives gas revenues by selling gas directly to customers at approved rates or by transporting gas through its pipelines at approved rates to customers that have purchased gas directly from other producers, brokers, or marketers. Total throughput was 224.2 MMDth for the year ended December 31, 2016. Gas sold and transported to residential and commercial customers was 97.2 MMDth representing 43 percent of throughput. Gas transported or sold to industrial and other contract customers was 127.0 MMDth representing 57 percent of throughput.

For the year ended December 31, 2016, gas utility revenues were $771.7 million, of which residential customers accounted for 67 percent and commercial accounted for 23 percent. Industrial and other contract customers accounted for 10 percent of revenues. Rates for transporting gas generally provide for the same margins earned by selling gas under applicable sales tariffs.

Availability of Natural Gas

The volumes of gas sold is seasonal and affected by variations in weather conditions. To meet seasonal demand, the Company's Indiana gas utilities have storage capacity at eight active underground gas storage fields and three propane plants. Periodically, purchased natural gas is injected into storage. The injected gas is then available to supplement contracted and manufactured volumes during periods of peak requirements. The volumes of gas per day that can be delivered during peak demand periods for each utility are located in "Item 2 Properties."

Natural Gas Purchasing Activity in Indiana

The Indiana utilities enter into short-term and long-term contracts with third party suppliers to purchase natural gas. Certain contracts are firm commitments under five and ten-year arrangements. During 2016, the Company, through its utility subsidiaries, purchased all of its gas supply from third parties and 67 percent was from a single third party.

Natural Gas Purchasing Activity in Ohio

On April 30, 2008, the PUCO issued an order which approved to exit the merchant function in the Company's Ohio service territory. As a result, substantially all of the Company's Ohio customers now purchase natural gas directly from retail gas marketers rather than from the Company. Exiting the merchant function has not had a material impact on earnings or financial condition.

Total Natural Gas Purchased Volumes
In 2016, Utility Holdings purchased 67.8 MMDth volumes of gas at an average cost of $3.75 per Dth inclusive of demand charges. The average cost of gas per Dth purchased for the previous four years was $3.96 in 2015, $5.42 in 2014, $4.60 in 2013, and $4.47 in 2012.

Electric Utility Services

At December 31, 2016, the Company supplied electric service to approximately 145,000 Indiana customers, including approximately 126,200 residential, 18,600 commercial, and 200 industrial and other customers. Average electric utility customers served were approximately 144,400 in 2016; 143,600 in 2015; and 142,900 in 2014.

The principal industries served include plastic products; automotive assembly and steel finishing; pharmaceutical and nutritional products; automotive glass; gasoline and oil products; ethanol; and coal mining.

Revenues

For the year ended December 31, 2016, retail electricity sales totaled 5,474.2 GWh, resulting in revenues of approximately $572.7 million. Residential customers accounted for 37 percent of 2016 revenues; commercial 27 percent; industrial 34 percent; and other 2 percent. In addition, in 2016 the Company sold 136.1 GWh through wholesale activities principally to the MISO. Wholesale revenues, including transmission-related revenue, totaled $33.1 million in 2016.

System Load

Total load for each of the years 2012 through 2016 at the time of the system summer peak, and the related reserve margin, is presented below in MW.

Date of summer peak load	6/22/2016	7/29/2015	8/27/2014	8/30/2013	7/24/2012
Total load at peak	1,096	1,088	1,095	1,102	1,259
Generating capability	1,248	1,248	1,298	1,298	1,298
Purchase supply (effective capacity)	37	37	38	38	136
Interruptible contracts & direct load control	75	72	71	48	60
Total power supply capacity	1,360	1,357	1,407	1,384	1,494
Reserve margin at peak	24 %	25 %	22 %	25 %	19 %

The winter peak load for the 2015-2016 season of approximately 868 MW occurred on January 13, 2016. The prior year winter peak load for the 2014-2015 season was approximately 933 MW, occurring on January 7, 2015.

Generating Capability
Installed generating capability as of December 31, 2016, was rated at 1,248 MW. Coal-fired generating units provide 1,000 MW of capacity, natural gas or oil-fired turbines used for peaking or emergency conditions provide 245 MW, and a landfill gas electric generation project provides 3 MW. Electric generation for 2016 was fueled by coal (97 percent), natural gas (2 percent), and landfill gas (less than 1 percent). Oil was used only for testing of gas/oil-fired peaking units. The Company generated approximately 4,138 GWh in 2016. Further information about the Company's owned generation is included in "Item 2 Properties."

Coal for coal-fired generating stations has been supplied from operators of nearby coal mines as there are substantial coal reserves in the southern Indiana area. Approximately 1.9 million tons were purchased for generating electricity during

2016. This compares to 2.5 million tons and 2.9 million tons purchased in 2015 and 2014, respectively. The utility's coal inventory was approximately 800 thousand tons at both December 31, 2016 and 2015.

Coal Purchases
The average cost of coal per ton purchased and delivered for the last five years was $54.24 in 2016, $55.22 in 2015, $55.18 in 2014, $58.38 in 2013, and $68.65 in 2012. Entering 2014, SIGECO had in place staggered term coal contracts with Vectren Fuels and one other supplier to provide supply for its generating units. During 2014, SIGECO entered into separate negotiations with Vectren Fuels and Sunrise Coal, LLC (Sunrise Coal), an Indiana-based wholly owned subsidiary of Hallador Energy Company, to modify its existing contracts as well as enter into new long-term contracts in order to secure its supply of coal with specifications that support its compliance with the Mercury and Air Toxins Rule. Subsequent to the sale of Vectren Fuels to Sunrise Coal in August 2014, all such contracts were assigned to Sunrise Coal and the Company purchases substantially all of its coal from Sunrise Coal.

Firm Purchase Supply
As part of its power portfolio, SIGECO is a 1.5 percent shareholder in the Ohio Valley Electric Corporation (OVEC), and based on its participation in the Inter-Company Power Agreement (ICPA) between OVEC and its shareholder companies, many of whom are regulated electric utilities, SIGECO has the right to 1.5 percent of OVEC's generating capacity output, which is approximately 32 MWs. Per the ICPA, SIGECO is charged demand charges which are based on OVEC's operating expenses, including its financing costs. Those demand charges are available to pass through to customers under SIGECO's fuel adjustment clause. Under the ICPA, and while OVEC's plants are operating, SIGECO is severally responsible for its participant share of OVEC's debt obligations. Based on OVEC's current financing, SIGECO's 1.5 percent potential obligation equates to approximately $21 million. Recently, due to the potential default of one of its shareholders with a 4.9 percent interest in OVEC under the ICPA, Moody's downgraded OVEC to Ba1. At this time, OVEC has both liquidity and financing capability that will allow it to continue to operate and provide power to its participating members, who include AEP, Duke and PPL. In 2016, the Company purchased approximately 157 GWh from OVEC.

In April 2008, the Company executed a capacity contract with Benton County Wind Farm, LLC to purchase as much as 30 MW from a wind farm located in Benton County, Indiana, with IURC approval. The contract expires in 2029. In 2016, the Company purchased approximately 61 GWh under this contract.

In December 2009, the Company executed a 20 year power purchase agreement with Fowler Ridge II Wind Farm, LLC to purchase as much as 50 MW of energy from a wind farm located in Benton and Tippecanoe Counties in Indiana, with the approval of the IURC. In 2016, the Company purchased 135 GWh under this contract.

MISO Related Activity
The Company is a member of the MISO, a FERC approved regional transmission organization. The MISO serves the electric transmission needs of much of the Midcontinent region and maintains operational control over the Company's electric transmission facilities as well as other utilities in the region. The Company is an active participant in the MISO energy markets, where it bids its generation into the Day Ahead and Real Time markets and procures power for its retail customers at Locational Marginal Pricing (LMP) as determined by the MISO market. MISO-related purchase and sale transactions are recorded using settlement information provided by the MISO. These purchase and sale transactions are accounted for on a net hourly position. Net purchases in a single hour are recorded as purchased power in Cost of fuel & purchased power and net sales in a single hour are recorded in Electric utility revenues. During 2016, in hours when purchases from the MISO were in excess of generation sold to the MISO, the net purchases were 1,320 GWh. During 2016, in hours when sales to the MISO were in excess of purchases from the MISO, the net sales were 136 GWh.

Interconnections

The Company has interconnections with Louisville Gas and Electric Company, Duke Energy Shared Services, Inc., Indianapolis Power & Light Company, Hoosier Energy Rural Electric Cooperative, Inc., and Big Rivers Electric Corporation providing the ability to simultaneously interchange approximately 900 MW during peak load periods. The Company, as required as a member of the MISO, has turned over operational control of the interchange facilities and its own transmission assets to the MISO. The Company in conjunction with the MISO must operate the bulk electric transmission system in accordance with NERC Reliability Standards. As a result, interchange capability varies based on regional transmission system configuration, generation dispatch, seasonal facility ratings, and other factors. The Company is in compliance with reliability standards promulgated by the NERC. Additionally, the Company is audited against those standards from time to time with no material issues or findings to date.

Competition

See a discussion on competition within the utility industry in "Item 1A Risk Factors, Utility Operating Risks" which is incorporated by reference herein.

Regulatory, Environmental, and Sustainability Matters

See “Item 7 Management’s Discussion and Analysis of Results of Operations and Financial Condition” regarding the Company’s regulatory environment, environmental, and sustainability matters.

Nonutility Group

The Company is involved in nonutility activities in two primary business areas: Infrastructure Services and Energy Services. Prior to August 29, 2014, the Company had activities in its Coal Mining business.

Infrastructure Services

Infrastructure Services provides underground pipeline construction and repair to utility infrastructure through its wholly owned subsidiaries Miller Pipeline, LLC (Miller or Miller Pipeline) and Minnesota Limited, LLC (Minnesota Limited). Infrastructure Services provides services to many utilities, including the Company’s utilities, as well as other industries. Infrastructure Services generated approximately $813 million in revenues for 2016, compared to $843 million in 2015 and $779 million in 2014.

Backlog represents the amount of revenue the Company expects to realize from work to be performed in the future on uncompleted contracts, including new contractual agreements on which work has not begun. Infrastructure Services operates primarily under two types of contracts, blanket contracts and bid contracts. Using blanket contracts, customers are not contractually committed to specific volumes of services, however the Company expects to be chosen to perform work needed by a customer in a given time frame. These contracts are typically awarded on an annual or multi-year basis. For blanket work, backlog represents an estimate of the amount of revenue that the Company expects to realize from work to be performed in the next twelve months on existing contracts or contracts the Company reasonably expects to be renewed or awarded based upon recent history or discussions with customers. Under bid contracts, customers are contractually committed to a specific service to be performed for a specific price, whether in total for a project or on a per unit basis. At December 31, 2016, Infrastructure Services had an estimated backlog of blanket contracts of $435 million and a backlog of bid contracts of $290 million, for a total backlog of $725 million. The estimated backlog at December 31, 2015 was $475 million for blanket contracts and $190 million for bid contracts, for a total of $665 million.

The backlog amounts above reflect estimates of revenues to be realized. Projects included in backlog can be subject to delays or cancellation as a result of regulatory requirements, adverse weather conditions, customer requirements, among other factors, which could cause actual revenue amounts to differ significantly from the estimates and revenues to be realized in periods other than originally expected.

See “Item 7 Management’s Discussion and Analysis of Results of Operations and Financial Condition” regarding additional narrative of Infrastructure Services business matters.

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Energy Services

Performance-based energy contracting operations and sustainable infrastructure, such as distributed generation and combined heat and power projects, are performed through Energy Systems Group, LLC (ESG), which is a wholly owned subsidiary of the Company. In 2014, the Company, through ESG, purchased the federal business unit of Chevron Energy Solutions (CES) (see Note 5 in the Company's Consolidated Financial Statements included in Item 8). ESG assists schools, hospitals, governmental facilities, and other private institutions with reducing energy and maintenance costs by upgrading their facilities with energy-efficient equipment. ESG is also involved in developing sustainable infrastructure projects. ESG’s customer base is primarily located throughout the Midwest, Mid-Atlantic, Southern and Southwestern United States. ESG generated revenues of approximately $260 million in 2016, compared to $200 million in 2015 and $130 million in 2014. ESG’s backlog of fixed price construction projects at December 31, 2016 was $234 million, compared to $226 million at December 31, 2015.

See “Item 7 Management’s Discussion and Analysis of Results of Operations and Financial Condition” regarding additional narrative of Energy Services business matters.

Coal Mining

Prior to August 29, 2014, Coal Mining owned, and through its contract miners, mined and sold coal to the Company's utility operations and to third parties through its wholly owned subsidiary, Vectren Fuels. On July 1, 2014, the Company announced that it had reached an agreement to sell its wholly owned coal mining subsidiary, Vectren Fuels, to Sunrise Coal. Sunrise Coal also owns and operates other coal mines in the Illinois Basin. On August 29, 2014, the transaction closed. Prior to the sale of Vectren Fuels, Coal Mining generated revenues of approximately $234 million in 2014.

Other Businesses

The Company has an investment in and loans to ProLiance Holdings, LLC (ProLiance). On June 18, 2013, ProLiance Holdings exited the natural gas marketing business through the disposition of certain of the net assets, along with the long-term pipeline and storage commitments, of its energy marketing business, ProLiance Energy, LLC to a subsidiary of Energy Transfer Partners, ETC Marketing, Ltd. The Company's remaining investment in ProLiance relates primarily to an investment in LA Storage, LLC. Consistent with its ownership percentage, the Company is allocated 61 percent of ProLiance’s profits and losses; however, governance and voting rights remain at 50 percent for each member; and therefore, the Company accounts for its investment in ProLiance using the equity method of accounting. Additional information regarding the investment in ProLiance is included in Note 7 in the Company's Consolidated Financial Statements included in Item 8.

The Other Businesses group also includes a variety of other legacy, wholly owned operations and investments in energy-related opportunities and services, among other investments. Details of these investments are included in Note 8 in the Company's Consolidated Financial Statements included in Item 8.

Personnel

As of December 31, 2016, the Company and its consolidated subsidiaries had approximately 5,800 employees. Of those employees, 700 are subject to collective bargaining arrangements negotiated by Utility Holdings and 3,100 are subject to collective bargaining arrangements negotiated by Infrastructure Services.

Utility Holdings

In April 2016, the Company reached a three-year labor agreement with Local 702 of the International Brotherhood of Electrical Workers, ending June 30, 2019. This labor agreement relates to employees of SIGECO.

In June 2015, the Company reached a three-year agreement with Local 175 of the Utility Workers Union of America, ending October 31, 2018. This labor agreement relates to employees of VEDO.

In May 2015, the Company reached a three-year agreement with Local 135 of the Teamsters, Chauffeurs, Warehousemen, and Helpers Union, ending September 23, 2018. This labor agreement relates to employees of SIGECO.

In July 2014, the Company reached a three-year labor agreement with Local 1393 of the International Brotherhood of Electrical Workers and United Steelworkers of America Locals 12213 and 7441, ending December 1, 2017. This labor agreement relates to employees of Indiana Gas.

Infrastructure Services

The Company, through its Infrastructure Services subsidiaries, negotiates various trade agreements through contractor associations. The two primary associations are the Distribution Contractors Association (DCA) and the Pipeline Contractors Association (PLCA). These trade agreements are with a variety of construction unions including Laborer's International Union of North America, International Union of Operating Engineers, United Association of Journeymen and Apprentices of the Plumbing and Pipe Fitting Industry, and Teamsters. The trade agreements through the DCA have varying expiration dates in 2017, 2020 and 2021. The trade agreements through the PLCA expire at various times in 2017. In addition, these subsidiaries have various project agreements and small local agreements. These agreements expire upon completion of a specific project or on various dates throughout the year.

ITEM 1A. RISK FACTORS

The Company is actively engaged in long-term strategic planning through initiative assessment, development and execution. The strategic planning process consistently engages the Company's Board of Directors and is updated as the Company's strategic environment changes. The result of that process is regularly communicated to all stakeholders, including investors, through a robust Investor Relations program. Further, the Company has a robust compliance and risk management program that promotes a culture of compliance. The Company is, however, subject to a variety of risks including execution on its strategies. Investors should consider carefully the following factors that could cause the Company's operating results and financial condition to be materially adversely affected.

Corporate Risks

Vectren is a holding company, and its assets consist primarily of investments in its subsidiaries.

Dividends on the Company's common stock depend on the earnings, financial condition, capital requirements and cash flow of its subsidiaries, principally Utility Holdings and Enterprises, and the distribution or other payment of earnings from those entities to the Company. Should the earnings, financial condition, capital requirements, cash flow, or legal requirements applicable to them restrict their ability to pay dividends or make other payments to the Company, its ability to pay dividends on its common stock could be limited and its stock price could be adversely affected. The Company's results of operations, future growth, and earnings and dividend goals also will depend on the performance of its subsidiaries. Additionally, certain of the Company's lending arrangements contain restrictive covenants, including the maintenance of a total debt to total capitalization ratio.

Deterioration in general economic conditions may have adverse impacts.

Economic conditions may have some negative impact on both gas and electric industrial and commercial customers. This impact may include volatility and unpredictability in the demand for natural gas and electricity, tempered growth strategies, significant conservation measures, and perhaps plant closures, production cutbacks, or bankruptcies. Economic conditions may also cause reductions in residential and commercial customer counts and lower revenues. It is also possible that an uncertain economy could affect costs including pension costs, interest costs, and uncollectible accounts expense. Economic and commodity price declines may be accompanied by a decrease in demand for products and services offered by nonutility operations and therefore lower revenues for those products and services. The economic conditions may have some negative impact on spending for utility and pipeline construction projects, demand for natural gas, and electricity, and spending on performance contracting and sustainable infrastructure expansion. It is also possible that unfavorable conditions could lead to the impairment of Company assets, including, its investment in ProLiance Holdings.

Financial market volatility could have adverse impacts.

The capital and credit markets may experience volatility and disruption. If market disruption and volatility occurs, there can be no assurance that the Company will not experience adverse effects, which may be material. These effects may include, but are not limited to, difficulties in accessing the short and long-term debt capital markets and the commercial paper market, increased borrowing costs associated with short-term debt obligations, higher interest rates in future financings, and a smaller potential pool of investors and funding sources. Finally, there is no assurance the Company will have access to the equity capital markets to obtain financing when necessary or desirable.

Change to United States laws, regulations, and policy may not have desired effects.

Policy and/or legislative changes in the areas of, among others, energy, comprehensive tax reform, environmental regulation, and/or infrastructure expenditures (including preference toward domestically sourcing expenditures) could have material impacts on the financial performance or condition of the Company. In addition the Company's implementation of policy changes may or may not be received favorably by the Company's stakeholders and/or government officials advocating policy change, both of which have reputational risk.

The pace at which federal policy can procedurally change may also impact the Company's operations. Certain policy changes may be able to be swiftly made, while changes in regulations that are already published in the Code of Federal Regulations, such as the Coal Combustion Residuals Rule, the Effluent Limitation Guidelines, and the Cooling Water Intake Rule, can likely be made only after separate notice and comment proceedings to revise and/or withdraw the published rule are held.

A downgrade (or negative outlook) in or withdrawal of Vectren's credit ratings could negatively affect its ability to access capital and its cost.

The following table shows the current ratings assigned to the Company and its rated subsidiaries by Moody's and Standard & Poor's:

	Current Rating	
	Moody's	Standard & Poor's
Vectren Corporation's corporate credit rating	not rated	A-
Utility Holdings and Indiana Gas senior unsecured debt	A2	A-
Utility Holdings commercial paper program	P-1	A-2
SIGECO's senior secured debt	Aa3	A

The current outlook for both Moody's and Standard & Poor's is stable. Both rating agencies categorize the ratings of the above securities as investment grade. A security rating is not a recommendation to buy, sell, or hold securities. The rating is subject to revision or withdrawal at any time, and each rating should be evaluated independently of any other rating. Standard & Poor's and Moody's lowest level investment grade rating is BBB- and Baa3, respectively.

If the rating agencies downgrade the Company's credit ratings, particularly below investment grade, or initiate negative outlooks thereon, or withdraw the Company's ratings or, in each case, the ratings of its subsidiaries, it may significantly limit the Company's access to the debt capital markets and the commercial paper market, and the Company's borrowing costs would likely increase. In addition, the Company would likely be required to pay a higher interest rate in future financings, and its potential pool of investors and funding sources would likely decrease. Finally, there is no assurance that the Company will have access to the equity capital markets to obtain financing when necessary or desirable.

The Company may need to raise capital through additional debt financing or by issuing additional equity securities.

The Company may need to raise additional capital in the future. The Company may raise additional funds through public equity or debt offerings or other financings. The additional issuance of equity securities, including securities that are convertible into or exchangeable for, or that represent the right to receive, common stock, will dilute the value of the Company's common stock. Any new debt financing the Company enters into may involve covenants that restrict the Company's operations more than current outstanding debt and credit facilities. These restrictive covenants could include limitations on additional borrowings, specific restrictions on the use of the Company's assets, as well as prohibitions or limitations on the Company's ability to create liens, pay dividends, receive distributions from subsidiaries, redeem stock, or make investments. These factors could hinder the Company's access to capital markets and therefore limit or delay the Company's ability to carry out capital expenditures.

Utility Operating Risks

Vectren's gas and electric utility sales are concentrated in the Midwest.

The operations of the Company's regulated utilities are concentrated in central and southern Indiana and west central Ohio and are therefore impacted by changes in the Midwest economy in general and changes in particular industries concentrated in the Midwest. These industries include automotive assembly, parts and accessories; feed, flour and grain processing; metal castings, plastic products; gypsum products; electrical equipment, metal specialties, glass and steel finishing; pharmaceutical and nutritional products; gasoline and oil products; ethanol; and coal mining. Changing market conditions, including changing regulation, changes in market prices of oil or other commodities, or changes in government regulation and assistance, may cause certain industrial customers to reduce or cease production and thereby decrease consumption of natural gas and/or electricity.

Vectren's regulated utilities operate in an increasingly competitive industry, which may affect its future earnings.

The utility industry has been undergoing structural change for several years, resulting in increasing competitive pressure faced by electric and gas utility companies. Increased competition, including those from cogeneration, private generation, solar, and other renewables opportunities for customers, may create greater risks to the stability of the Company's earnings generally and may in the future reduce its earnings from retail electric and gas sales. In this regard, the deployment and commercialization of technologies, such as private renewable energy sources, cogeneration facilities, and energy storage, have the potential to change the nature of the utility industry and reduce demand for the Company's electric and gas products and services. If the Company is not able to appropriately adapt to structural changes in the utility industry as a result of the development of these technologies, this may have an adverse effect on the Company's financial condition and results of operations. Additionally, several states, including Ohio, have passed legislation that allows customers to choose their electricity supplier in a competitive market. Indiana has not enacted such legislation. Ohio regulation also provides for choice of commodity providers for all gas customers. The Company has implemented this choice for its gas customers in Ohio. The state of Indiana has not adopted any regulation requiring gas choice in the Company's Indiana service territories; however, the Company operates under approved tariffs permitting certain industrial and commercial large volume customers to choose their commodity supplier. The Company cannot provide any assurance that increased competition or other changes in legislation, regulation or policies will not have a material adverse effect on its business, financial condition or results of operations.

A significant portion of Vectren's electric utility sales are space heating and cooling. Accordingly, its operating results may fluctuate with variability of weather.

The Company’s electric utility sales are sensitive to variations in weather conditions. In this regard, many customers rely on electricity to heat and cool their homes and businesses and, as a result, the Company’s results of operations may be adversely affected by warmer-than-normal heating season weather or colder-than-normal cooling season weather. Accordingly, demand for electricity used for heating purposes is generally at its highest during the peak heating season of October through March and is directly affected by the severity of the winter weather. The Company forecasts utility sales on the basis of normal weather. Since the Company does not have a weather-normalization mechanism for its electric operations, significant variations from normal weather could have a material impact on its earnings. However, the impact of weather on the gas operations in the Company’s Indiana territories has been significantly mitigated through the implementation of a normal temperature adjustment mechanism. Additionally, the implementation of a straight fixed variable rate design mitigates most weather variations related to Ohio residential and commercial gas sales.

Vectren’s utilities are exposed to increasing regulation, including pipeline safety, environmental, and cybersecurity regulation.

The Company's utilities are subject to regulation by federal, state, and local regulatory authorities and are exposed to public policy decisions that may negatively impact the Company's earnings. In particular, the Company is subject to regulation by the FERC, the NERC, the EPA, the IURC, the PUCO, the DOT, including PHMSA, the Department of Energy (DOE), the Occupational Safety and Health Administration (OSHA), and the Department of Homeland Security (DHS). These authorities regulate many aspects of its generation, transmission and distribution operations, including construction and maintenance of facilities, operations, and safety. In addition, the IURC, the PUCO, and the FERC approve its utility-related debt and equity issuances, regulate the rates that the Company's utilities can charge customers, the rate of return that the Company's utilities are authorized to earn, and their ability to timely recover gas and fuel costs and investments in infrastructure. Further, there are consumer advocates and other parties that may intervene in regulatory proceedings and affect regulatory outcomes.

Trends Toward Stricter Standards
With the historical trend toward stricter standards, greater regulation, more extensive permit requirements, and an increase in the number and types of assets operated that are subject to regulation, the Company's investment in infrastructure and the associated operating costs have increased and may increase in the future.

Pipeline Safety Considerations
The Company monitors and maintains its natural gas distribution system to ensure that natural gas is delivered in a safe, efficient, and reliable manner. The Company's natural gas utilities are currently engaged in replacement programs in both Indiana and Ohio, the primary purpose of which is preventive maintenance and continual renewal and improvement. The Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (Pipeline Safety Law) was signed into law on January 3, 2012 and on March 18, 2016 PHMSA published a notice of proposed rulemaking on the safety of gas transmission and gathering lines. The rule addresses many of the remaining requirements of the 2011 Pipeline Safety Act, with a particular focus on extending integrity management rules to address a much larger portion of the natural gas infrastructure and adds requirements to address broader threats to the integrity of a pipeline system. While some compliance costs remain uncertain, these rules result in further investment in pipeline inspections, and where necessary, additional investments in pipeline infrastructure. As such, the rule results in increased levels of operating expenses and capital expenditures associated with the Company's natural gas distribution and transmission systems as evidenced by recent regulatory filings and resulting Commission Orders in Indiana and Ohio for Indiana Gas, SIGECO, and VEDO.

Environmental Considerations
The Company's utility operations and properties are subject to extensive environmental regulation pursuant to a variety of federal, state, and local laws and regulations. These environmental regulations impose, among other things, restrictions, liabilities, and obligations in connection with the storage, transportation, treatment, and disposal of hazardous substances and limit airborne emissions from electric generating facilities, including particulate matter, sulfur dioxide (SO_2), nitrogen oxide (NOx), mercury, and non-hazardous substances such as coal combustion residuals, among others. Environmental legislation/regulation also requires that facilities, sites, and other properties associated with the Company's operations be operated, maintained, abandoned, and reclaimed to the satisfaction of applicable regulatory authorities. The Company's current costs to comply with these laws and regulations are significant to its results of operations and financial condition. Moreover, these compliance costs will substantially change the nature of the Company's generation fleet, as outlined in the Company’s preferred integrated resource plan (IRP) that was submitted to the IURC in December 2016.

Climate Change Considerations

The Company and the State of Indiana are subject to the requirement of the Clean Power Plan (CPP) rule, which requires a 32 percent reduction in carbon emissions from 2005 levels. While implementation of the rule remains uncertain due to the U.S. Supreme Court stay that was granted in February 2016 to delay the regulation while being challenged in court, regulations as written in the final rule may substantially affect both the costs and operating characteristics of the Company's fossil fuel generating plans and natural gas distribution business.

Evolving Physical Security and Cybersecurity Standards and Considerations
The frequency, size and variety of physical security and cybersecurity threats against critical infrastructure companies continues to grow, as do the evolving frameworks, standards and regulations intended to keep pace with and address these threats. There continues to be a marked increase in interest from both federal and state regulatory agencies related to physical security and cybersecurity in general, and specifically in critical infrastructure sectors, including the electric and natural gas sectors. The Company has dedicated internal and third party physical security and cybersecurity teams and maintains vigilance with regard to the communication and assessment of physical security and cybersecurity risks and the measures employed to protect information technology assets, critical infrastructure, the Company and its customers from these threats. Physical security and cybersecurity threats, however, constantly evolve in attempts to identify and capitalize on any weakness or unprotected areas. If these measures were to fail or if a breach were to occur, it could result in impairment or loss of critical functions, operating reliability, customer, or other confidential information. The ultimate effects, which are difficult to quantify with any certainty, are partially limited through insurance.

Increasing regulation and infrastructure replacement programs could affect Vectren's utility rates charged to customers, its costs, and its profitability.

Any additional expenses or capital incurred by the Company's utilities, as it relates to complying with increasing regulation and other infrastructure replacement activities are expected to be recovered from customers in its service territories through increased rates. Increased rates have an impact on the economic health of the communities served. New regulations could also negatively impact industries in the Company's service territory, including industries in which the Company operates.

The Company's utilities' ability to obtain rate increases and to maintain current authorized rates of return depends in part on continued interpretation of laws within the current regulatory framework. There can be no assurance that the Company will be able to obtain rate increases, or rate supplements, or earn currently authorized rates of return. Indiana and Ohio have passed laws allowing utilities to recover a significant amount of the costs of complying with federal mandates or other infrastructure replacement expenditures, and in Ohio, other capital investments outside of a base rate proceeding. However, these activities may have at least a short-term adverse impact on the Company's cash flow and financial condition.

In addition, failure to comply with new or existing laws and regulations may result in fines, penalties, or injunctive measures and may not be recoverable from customers and could result in a material adverse effect on the Company's financial condition and results of operations.

Vectren's regulated energy delivery operations are subject to various risks.

A variety of hazards and operations risks, such as leaks, accidental explosions, and mechanical problems, are inherent in the Company’s gas and electric distribution and transmission activities. If such events occur, they could cause substantial financial losses and result in injury to or loss of human life, significant damage to property, environmental pollution, and impairment of operations. The location of pipelines, storage facilities, and the electric grid near populated areas, including residential areas, commercial business centers, and industrial sites, could increase the level of damages resulting from these risks. These activities may subject the Company to litigation or administrative proceedings from time to time. Such litigation or proceedings could result in substantial monetary judgments, fines, or penalties or be resolved on unfavorable terms. In accordance with customary industry practices, the Company maintains insurance against a significant portion, but not all, of these risks and losses. To the extent that the occurrence of any of these events is not fully covered by insurance, it could adversely affect the Company’s financial condition and results of operations.

Vectren’s regulated power supply operations are subject to various risks.

The Company’s electric generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses, and increased purchase power costs. Such operational risks can arise from circumstances such as facility shutdowns due to equipment failure or operator error; interruption of fuel supply or increased prices of fuel as contracts expire; disruptions in the delivery of electricity; inability to comply with regulatory or permit requirements; labor disputes; and natural disasters. Further, the Company's coal supply is purchased largely from a single, unrelated party and, although the coal supply is under long-term contract, the loss of this supplier could impact operations. As recently announced, the Company's preferred IRP plan could impact the future operations of some of the Company's power plants, as well as introduce the need for approval and timely recovery of new capital investments as the plan is implemented. Executing upon the preferred IRP introduces additional risks such as; timely approval to build and own generation, ability to meet capacity requirements, ability to procure resources needed to build new generation at a reasonable cost, ability to appropriately estimate costs of new generation, ability to fully recover the investments made in retiring generation, scarcity of resources and labor, and workforce retention, development and training.

The Company participates in the MISO.

The Company is a member of the MISO, which serves the electric transmission needs of much of the Midcontinent region and maintains operational control over the Company's electric transmission facilities, as well as other utilities in the region. As a result of such control, the Company's continued ability to import power, when necessary, and export power to the wholesale market has been, and may continue to be, impacted.

The need to expend capital for improvements to the regional electric transmission system, both to the Company's facilities as well as to those facilities of adjacent utilities, over the next several years is expected to be significant. The Company timely recovers its investment in certain new electric transmission projects that benefit the MISO infrastructure at a FERC approved rate of return.

Also, the MISO allocates operating costs and the cost of multi-value projects throughout the region to its participating utilities such as the Company's regulated electric utility, and such costs are significant. Adjustments to these operating costs, including adjustments that result from participants entering or leaving the MISO, could cause increases or decreases to customer bills. The Company timely recovers its portion of MISO operating expenses as tracked costs.

Volatility in the wholesale price of natural gas, coal, and electricity could reduce earnings and working capital.

The Company's regulated operations have limited exposure to commodity price risk for transactions involving purchases and sales of natural gas, coal, and purchased power for the benefit of retail customers due to current state regulations, which, subject to compliance with those regulations, allow for recovery of the cost of such purchases through natural gas and fuel cost adjustment mechanisms. However, significant volatility in the price of natural gas, coal, or purchased power may cause existing customers to conserve or motivate them to switch to alternate sources of energy as well as cause new home developers, builders, and new customers to select alternative sources of energy. Decreases in volumes sold could reduce earnings. The decrease would be more significant in the absence of constructive regulatory orders, such as those authorizing revenue decoupling, lost margin recovery, and other innovative rate designs. A decline in new customers could impede growth in future earnings. In addition, during periods when commodity prices are higher than historical levels, working capital costs could increase due to higher carrying costs of inventories and cost recovery mechanisms, and customers may have trouble paying higher bills leading to increased bad debt expenses. Additionally, significant oil price fluctuations and impact on the ability to continue shale gas drilling may impact the price of natural gas and purchased power.

Increased conservation efforts and technology advances, which result in improved energy efficiency or the development of alternative energy sources, may result in reduced demand for the Company's energy products and services.

The trend toward increased conservation and technological advances, including installation of improved insulation and the development of more efficient furnaces and air conditioners and other heating and cooling devices as well as lighting, may reduce the demand for energy products. Prices for natural gas are subject to fluctuations in response to changes in supply and other market conditions. During periods of high energy commodity costs, the Company's prices generally increase, which may lead to customer conservation. Federal and state regulation may require mandatory conservation measures, which would reduce the demand for energy products. Certain federal or state regulation may also impose restrictions on building construction and design in efforts to increase conservation which may reduce demand for natural gas and electricity. In addition, the Company's customers, especially large commercial and industrial customers, may choose to employ various technological advances to develop alternative energy sources, such as the construction and development of wind power, solar technology, or electric cogeneration facilities. Increased conservation efforts and the utilization of technological advances to increase energy efficiency or to develop alternate energy sources could lead to a reduction in demand for the Company's energy products and services, which could have an adverse effect on its revenues and overall results of operations.

Nonutility Operating Risks

The performance of Vectren's nonutility businesses is subject to certain risks.

Execution of the Company's nonutility business strategies and the success of efforts to invest in and develop new opportunities in the nonutility business area are subject to a number of risks. These risks include, but are not limited to, the effects of weather; changing market conditions, including changes in market prices for various forms of energy; failure of installed performance contracting products to operate as planned; failure to properly estimate the cost to construct projects; loss of key management and knowledge-based employees, including the inability to attract and retain qualified employees; the inability to effectively maintain regulatory compliance programs; potential legislation or regulations that may limit CO_2 and other greenhouse gases emissions; operating accidents that may require environmental remediation; creditworthiness of customers and joint venture partners; changes in federal, state or local legal and regulatory requirements, such as changes in tax laws or rates; and environmental or cybersecurity regulations.

The Company's nonutility businesses support its regulated utilities pursuant to service contracts by providing infrastructure services. In most instances, the Company's ability to maintain these service contracts depends upon regulatory discretion, and there can be no assurance it will be able to obtain future service contracts, or that existing arrangements will not be revisited.

Nonutility infrastructure services operations could be adversely affected by a number of factors.

Infrastructure Services results are dependent on a number of factors. The industry is competitive and contracts are subject to a bidding process. Should Infrastructure Services be unsuccessful in bidding contracts, results of operations could be impacted. Infrastructure Services enters into a variety of contracts, some of which are fixed price. Through competitive bidding, the volume of contracted work could vary significantly from year to year. Further, to the extent there are unanticipated cost increases in completion of the contracted work, the profit margin realized on any single project could be reduced. Additionally, Infrastructure Services contributes to several multiemployer pension plans under collective bargaining agreements with unions representing employees covered by those agreements. A significant increase to the funding requirements could adversely impact financial condition, results of operations, and cash flows. Changes in legislation and regulations impacting the sectors in which the customers served by Infrastructure Services operate could impact operating results. Other risks include, but are not limited to: failure to properly construct pipeline infrastructure; cancellation of projects by customers and/or reductions in the scope of the projects; changes in the timing of projects; the inability to obtain materials and equipment required to perform services from suppliers and manufacturers; and changes in the market prices of oil and natural gas that would affect the demand for infrastructure construction and/or the project margin realized on projects.

Nonutility energy services operations could be adversely affected by a number of factors.

Energy Services results are dependent on a number of factors. The industry is competitive and many of the contracts are subject to a bidding process. Should Energy Services be unsuccessful in bidding contracts for certain federal Indefinite Delivery/Indefinite Quantity (IDIQ) contracts, results of operations could be impacted. Through competitive bidding, the volume of contracted work could vary significantly from year to year. Further, to the extent there are unanticipated cost increases in completion of the contracted work, the profit margin realized on any single project could be reduced. Changes in legislation, regulations and government policies impacting the customers served by Energy Services, could impact operating results. Other risks include, but are not limited to: continuation of the federal Energy Savings Performance Contracting (ESPC) and Utility Energy Services Contract (UESC) programs; the inability of customers to finance projects; risks associated with projects owned or operated; failure to appropriately design, construct, or operate projects; and cancellation of projects by customers and/or reductions in the scope of the projects.

Other Corporate Operating Risks

The Company is exposed to physical and financial risks related to the uncertainty of climate change.

A changing climate creates uncertainty and could result in broad changes, both physical and financial in nature, to the Company’s service territories. These impacts could include, but are not limited to, population shifts; changes in the level of annual rainfall; changes in the overall average temperature; and changes to the frequency and severity of weather events such as thunderstorms, wind, tornadoes, and ice storms that can damage infrastructure. Such changes could impact the Company in a number of ways including the number and type of customers in the Company’s service territories; an increase to the cost of providing service; an increase in the amount of service interruptions; impacts to the Company's workforce; and an increase in the likelihood of capital expenditures to replace damaged infrastructure.

To the extent climate change impacts a region’s economic health, it may also impact the Company’s revenues, costs, and capital structure and thus the need for changes to rates charged to regulated customers. Rate changes themselves can impact the economic health of the communities served and may in turn adversely affect the Company’s operating results.
Customers' energy needs vary with weather conditions. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease. Increased energy use due to weather changes may require additional generating resources, transmission, and other infrastructure to serve increased load. Decreased energy use may require the Company to retire current infrastructure that is no longer needed.

Increased derivatives regulations could impact results.

The Company uses commodity derivative instruments in conjunction with procurement activities. The Company may also periodically use interest rate derivative instruments to minimize the impact of interest rate fluctuations associated with anticipated debt issuances.

Significant rule-making by numerous governmental agencies, particularly the Commodity Futures Trading Commission (CFTC), continues to evolve and has been subject to a number of extensions and delays. The Company continues to evaluate the impacts of these rulemakings and interpretations as they become available.

Vectren’s nonutility operations have performance and warranty obligations, some of which are guaranteed by Vectren.

In the normal course of business, certain subsidiaries of the Company issue performance bonds and other forms of assurance that commit them to timely install infrastructure, operate facilities, pay vendors or subcontractors, and support warranty obligations. Vectren Corporation, as the parent company, will from time to time guarantee its subsidiaries’ commitments. These guarantees do not represent incremental consolidated obligations; rather, they represent parental guarantees of subsidiary obligations in order to allow those subsidiaries the flexibility to conduct business without posting other forms of collateral. The Company has not been called upon to satisfy any obligations pursuant to these parental guarantees.

Certain of Vectren's nonutility operations face a customer concentration risk. The loss of such a customer would result in a decline in revenue and could have an adverse effect on the results of operations and cash flows.

From time to time, revenues and total outstanding receivables from various customers of Infrastructure Services may individually account for more than 5 percent of the Company's consolidated operating revenues and receivables, respectively. While the Company believes that the loss of any one customer would not have a material impact on its financial position or results of operations, the loss of a customer of this significance or a significant decline in related customer revenues could have an adverse effect on the results of operations and cash flows of Infrastructure Services.

From time to time, Vectren is subject to material litigation and regulatory proceedings.

From time to time, the Company may be subject to material litigation and regulatory proceedings, including matters involving compliance with federal and state laws, regulations or other matters. There can be no assurance that the outcome of these matters will not have a material adverse effect on the Company’s business, prospects, corporate reputation, results of operations, or financial condition.

The investment performance of pension plan holdings and other factors impacting pension plan costs could impact Vectren’s liquidity and results of operations.

The costs associated with the Company sponsored retirement plans, including certain multiemployer plans at Infrastructure Services, are dependent on a number of factors, such as the rates of return on plan assets; discount rates; the level of interest rates used to measure funding levels; changes in actuarial assumptions including assumed mortality; future government regulations; changes in plan design, and Company contributions. In addition, the Company could be required to provide for significant funding of these defined benefit pension plans. Such cash funding obligations could have a material impact on liquidity by reducing cash flows for other purposes and could negatively affect results of operations.

Catastrophic events, such as terrorist attacks, acts of civil unrest, and acts of God, may adversely affect Vectren’s facilities and operations, corporate reputation, financial condition and results from operations.

Catastrophic events such as fires, earthquakes, explosions, floods, ice storms, tornadoes, terrorist acts, cyber attacks or similar occurrences could adversely affect the Company’s facilities, operations, corporate reputation, financial condition and results of operations. Either a direct act against Company-owned generating facilities or transmission and distribution infrastructure or an act against the infrastructure of neighboring utilities or interstate pipelines that are used by the Company to transport power and natural gas could result in the Company being unable to deliver natural gas or electricity for a prolonged period. Additionally, an act against the Company's nonutility businesses could result in the Company being unable to provide utility infrastructure services, performance-based energy contracting services, or sustainable infrastructure services. In the event of a severe disruption resulting from such events, the Company has contingency plans and employs crisis management to respond and recover operations. Despite these measures, if such an occurrence were to occur, results of operations and financial condition could be materially adversely affected.

Cyber attacks or similar occurrences may adversely affect Vectren's facilities, operations, corporate reputation, financial condition and results of operations.

The Company relies on information technology networks, telecommunications, and systems to, among other things, 1) operate its generating facilities, 2) engage in asset management activities, 3) process, transmit and store sensitive electronic information including intellectual property, proprietary business information and that of the Company’s suppliers and business partners, personally identifiable information of customers and employees, and data with respect to invoicing and the collection of payments, accounting, procurement, and supply chain activities, and 4) process financial information and results of operations for internal reporting purposes and to comply with financial reporting, legal, and tax requirements. Despite the Company’s security measures, any information technology system may be vulnerable to attacks by hackers or breached due to malfeasance, employee error, sabotage, or other disruptions. Security breaches or general communication disruption of this information technology infrastructure could lead to system disruptions, business interruption, generating facility shutdowns or unauthorized disclosure of confidential information. In particular, any data loss or information security lapses resulting in the compromise of personal information or the improper use or disclosure of sensitive or classified information could result in claims, remediation costs, regulatory sanctions against the Company, loss of current and future contracts, and serious harm to the Company's reputation. While the Company has implemented policies, procedures, and controls to prevent and detect these activities, not all misconduct may be prevented. In the event of a severe infrastructure system disruption or generating facility shutdown resulting from such events, the Company has contingency plans and employs crisis management to respond and recover operations. Despite these measures, if such an attack or security breach were to occur, results of operations and financial condition could be materially adversely affected. The ultimate effects, which are difficult to quantify with any certainty, are partially limited through insurance.

Workforce risks could affect Vectren’s financial results.

The Company is subject to various workforce risks, including but not limited to, the risk that it will be unable to 1) attract and retain qualified and diverse personnel; 2) effectively transfer the knowledge and expertise of an aging workforce to new personnel as those workers retire; 3) react to a pandemic illness; 4) manage the migration to more defined contribution and high deductible employee benefit packages; and 5) that it will be unable to reach collective bargaining arrangements with the unions that represent certain of its workers, which could result in work stoppages.

Vectren’s ability to effectively manage its third party contractors, agents, and business partners could have a significant impact on the Company’s business and reputation.

The Company relies on third party contractors and other agents and business partners to perform some of the services provided to its customers, as well as assist with the monitoring of physical security and cybersecurity functions. Any misconduct by these third parties, or the Company’s inability to properly manage them, could adversely impact the provision of services to customers and the quality of services provided. Misconduct could include fraud or other improper activities, such as falsifying records and violations of laws. Other examples could include the failure to comply with the Company’s policies and procedures or with government procurement regulations, regulations regarding the use and safeguarding of classified or other protected information, legislation regarding the pricing of labor and other costs in government contracts, laws and regulations relating to environmental, health or safety matters, lobbying or similar activities, and any other applicable laws or regulations. Any data loss or information security lapses resulting in the compromise of personal information or the improper use or disclosure of sensitive or classified information could result in claims, remediation costs, regulatory sanctions against the Company, loss of current and future contracts, and serious harm to its reputation. Although the Company has implemented policies, procedures, and controls to prevent and detect these activities, these precautions may not prevent all misconduct, and as a result, the Company could face unknown risks or losses. The Company's failure to comply with applicable laws or regulations or misconduct by any of its contractors, agents, or business partners could damage its reputation and subject it to fines and penalties, restitution or other damages, loss of current and future customer contracts and suspension or debarment from contracting with federal, state or local government agencies, any of which would adversely affect the business and future results.

Vectren may not have adequate insurance coverage for all potential liabilities.

Natural risks, as well as other hazards associated with the Company’s operations, can cause significant personal injury or loss of life, severe damage to and destruction of property, plant and equipment, contamination of, or damage to, the environment and suspension of operations. The Company maintains an amount of insurance protection that management believes is appropriate, but there can be no assurance that the amount of insurance will be sufficient or effective under all circumstances and against all hazards or liabilities to which the Company may be subject. A claim for which the Company is not adequately insured could materially harm the Company’s financial condition. Further, due to the cyclical nature of the insurance markets, management cannot provide assurance that insurance coverage will continue to be available on terms similar to those presently in place.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Gas Utility Services

Indiana Gas owns and operates four active gas storage fields located in Indiana covering 58,100 acres of land with an estimated ready delivery from storage capability of 5.7 BCF of gas with maximum peak day delivery capabilities of 155,500 MCF per day. Indiana Gas also owns and operates three liquified petroleum (propane) air-gas manufacturing plants located in Indiana with the ability to store 1.5 million gallons of propane and manufacture for delivery 33,000 MCF of manufactured gas per day. In addition to its company owned storage and propane capabilities, Indiana Gas has contracted for 16.1 BCF of interstate natural gas pipeline storage service with a maximum peak day delivery capability of 239,200 MMBTU per day. Indiana Gas' gas delivery system includes approximately 13,100 miles of distribution and transmission mains, all of which are in Indiana except for pipeline facilities extending from points in northern Kentucky to points in southern Indiana so that gas may be transported to Indiana and sold or transported by Indiana Gas to ultimate customers in Indiana.

SIGECO owns and operates three active underground gas storage fields located in Indiana covering 6,100 acres of land with an estimated ready delivery from storage capability of 5.3 BCF of gas with maximum peak day delivery capabilities of 88,000 MCF per day. In addition to its company owned storage delivery capabilities, SIGECO has contracted for 0.4 BCF of interstate natural gas pipeline storage service with a maximum peak day delivery capability of 16,800 MMBTU per day. SIGECO's gas delivery system includes 3,300 miles of distribution and transmission mains, all of which are located in Indiana.

VEDO has 11.8 BCF of interstate natural gas pipeline storage service with a maximum peak day delivery capability of 246,100 MMBTU per day. The Company has released its Ohio storage service to those retail gas marketers now supplying VEDO with natural gas, and those suppliers are responsible for the demand charges. VEDO's gas delivery system includes 5,600 miles of distribution and transmission mains, all of which are located in Ohio.

Electric Utility Services

SIGECO's installed generating capacity as of December 31, 2016, was rated at 1,248 MW. SIGECO's coal-fired generating facilities are the A.B. Brown Generating Station (AB Brown) with two units totaling 490 MW of combined capacity, located in Posey County approximately eight miles east of Mt. Vernon, Indiana; the F.B. Culley Generating Station (Culley) with two units totaling 360 MW of combined capacity; and Warrick Unit 4 (Warrick) with 150 MW of capacity. Both the Culley and Warrick Stations are located in Warrick County near Yankeetown, Indiana. SIGECO's gas-fired turbine peaking units are: two 80 MW gas turbines (Brown Unit 3 and Brown Unit 4) located at AB Brown; one Broadway Avenue Gas Turbine located in Evansville, Indiana with a capacity of 65 MW; and two Northeast Gas Turbines located northeast of Evansville in Vanderburgh County, Indiana with a combined capacity of 20 MW. The Brown Unit 3 and Broadway Avenue Unit 2 turbines are also equipped to burn oil. Total capacity of SIGECO's five gas turbines is 245 MW, and these units are generally used only for reserve, peaking, or emergency purposes. SIGECO also has a landfill gas electric generation project in Pike County, Indiana with a total generation capability of 3 MW.

SIGECO's transmission system consists of approximately 1000 circuit miles of 345kV, 138kV and 69kV lines. The transmission system also includes 34 substations with an installed capacity of 4,800 megavolt amperes (Mva). The electric distribution system includes 4,558 circuit miles of lower voltage overhead lines and 436 trench miles of conduit containing 2,386 circuit miles of underground distribution cable. The distribution system also includes 86 distribution substations with an installed capacity of 2,100 Mva and 55,000 distribution transformers with an installed capacity of 2,385 Mva.

SIGECO owns utility property outside of Indiana approximating 24 miles of 138kV and 345kV electric transmission lines, which are included in the 1000 circuit miles discussed above. These assets are located in Kentucky and interconnect with Louisville Gas and Electric Company's transmission system at Cloverport, Kentucky and with Big Rivers Electric Cooperative at Sebree, Kentucky.

Other Properties

Vectren Affiliated Utilities, Inc., a subsidiary of the Company, owns and operates one active gas storage field located in Indiana covering 2,900 acres of land with an estimated ready delivery from storage capability of 0.8 BCF of gas with maximum peak day delivery capability of 5,000 MCF per day. In addition to the storage field, a compressor station with two 1,500 hp compressors is capable of moving gas from storage to either of the two pipeline suppliers in the area, or compress unidirectionally from one pipeline supplier to the other pipeline supplier.

Property Serving as Collateral

SIGECO's properties are subject to the lien of the First Mortgage Indenture dated as of April 1, 1932, between SIGECO and Bankers Trust Company, as Trustee, and Deutsche Bank, as successor Trustee, as supplemented by various supplemental indentures.

ITEM 3. LEGAL PROCEEDINGS

The Company is party to various legal proceedings and audits and reviews by taxing authorities and other government agencies arising in the normal course of business. In the opinion of management, there are no legal proceedings or other regulatory reviews or audits pending against the Company likely to have a material adverse effect on its financial position, results of operations, or cash flows. See the notes to the consolidated financial statements regarding commitments and contingencies, environmental matters, and rate and regulatory matters. The consolidated financial statements are included in “Item 8 Financial Statements and Supplementary Data.”

During the third quarter of 2014, the Company was notified of claims by a group of current and former SIGECO employees (“claimants”) who participated in the Pension Plan for Salaried Employees of SIGECO (“SIGECO Salaried Plan”). That plan was merged into the Vectren Corporation Combined Non-Bargaining Retirement Plan (“Vectren Combined Plan”) effective July 1, 2000. The claims related to the claimants’ election for benefits to be calculated under the Vectren Combined Plan’s cash-balance formula rather than the SIGECO Salaried Plan formula. On March 12, 2015, certain claimants filed a Class Action Complaint against the Vectren Combined Plan (Plan) and the Company. The Company denied the allegations set forth in the Complaint and moved to dismiss the case. In April 2016, the court dismissed part of the complaint but allowed the remaining claims to proceed. On February 6, 2017, the parties reached a settlement in principle to resolve the matter. The terms of the settlement in principle are not expected to have a material impact on the Plan or the Company.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

PART II

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

Market Data, Dividends Paid, and Holders of Record

The Company’s common stock trades on the New York Stock Exchange under the symbol ‘‘VVC.’’ For each quarter in 2016 and 2015, the high and low sales prices for the Company’s common stock as reported on the New York Stock Exchange and dividends paid are presented below.

	Cash Dividend	Common Stock Price Range High	Low
2016			
First Quarter	$0.400	$51.00	$39.43
Second Quarter	$0.400	$52.68	$46.96
Third Quarter	$0.400	$53.33	$47.87
Fourth Quarter	$0.420	$53.05	$46.52
2015			
First Quarter	$0.380	$49.47	$42.47
Second Quarter	$0.380	$45.24	$38.41
Third Quarter	$0.380	$43.08	$37.26
Fourth Quarter	$0.400	$47.00	$39.98

On November 2, 2016 the board of directors declared a dividend of $0.42 per share, payable on December 1, 2016, to common shareholders of record on November 15, 2016.

As of January 31, 2017, there were 7,914 registered shareholders of the Company’s common stock.

Quarterly Share Purchases

Periodically, the Company purchases shares from the open market to satisfy share requirements associated with the Company’s share-based compensation plans; however, no such open market purchases were made during the quarter ended December 31, 2016.

Dividend Policy

Common stock dividends are payable at the discretion of the Board of Directors, out of legally available funds. The Company’s policy is to target a 60 percent consolidated payout ratio; however, this percentage has varied and could continue to vary due to short-term earnings volatility. The Company has increased its dividend for 57 consecutive years. While the Company is under no contractual obligation to do so, it intends to continue to pay dividends and to increase the dividend annually. Nevertheless, should the Company’s financial condition, operating results, capital requirements, or other relevant factors change, future dividend payments, and the amounts of these dividends, will be reassessed.

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ITEM 6. SELECTED FINANCIAL DATA

The following selected financial data is derived from the Company's audited consolidated financial statements and should be read in conjunction with those financial statements and notes thereto contained in this Form 10-K.

	Year Ended December 31,				
(In millions, except per share data)	2016	2015	2014	2013	2012
Operating Data:					
Operating revenues	$2,448.3	$2,434.7	$2,611.7	$2,491.2	$2,232.8
Operating income	$381.5	$361.8	$314.5	$333.6	$352.5
Net income	$211.6	$197.3	$166.9	$136.6	$159.0
Weighted average common shares outstanding	82.8	82.7	82.5	82.3	82.0
Fully diluted common shares outstanding	82.8	82.7	82.5	82.4	82.1
Basic earnings per share on common stock	$2.55	$2.39	$2.02	$1.66	$1.94
Diluted earnings per share on common stock	$2.55	$2.39	$2.02	$1.66	$1.94
Dividends per share on common stock	$1.620	$1.540	$1.460	$1.425	$1.405
Balance Sheet Data:					
Total assets	$5,800.7	$5,400.0	$5,137.8	$5,079.5	$5,073.2
Long-term debt, net	$1,589.9	$1,712.9	$1,339.1	$1,767.9	$1,537.5
Common shareholders' equity	$1,768.1	$1,683.8	$1,606.6	$1,554.3	$1,526.1

Results include the loss on disposition and operating results of Coal Mining in 2014 and the loss on disposition and operating results attributable to the Company's investment in ProLiance in 2013. See additional information in footnotes 6 and 7 to the financial statements in Item 8 for further information regarding the Coal Mining and ProLiance transactions. Total assets in all periods presented reflect the retrospective impacts of the adoption of ASU 2015-17, Balance Sheet Classification of Deferred Taxes, in 2015. Total assets and Long-term debt in all periods presented reflect the retrospective impacts of the adoption of ASU 2015-03, Presentation of Debt Issuance Costs, in 2016.

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

Executive Summary of Consolidated Results of Operations

In this discussion and analysis, the Company analyzes contributions to consolidated earnings and earnings per share from its Utility Group and Nonutility Group separately. Because each group operates independently and offers different energy related products and services, the analysis separately addresses the opportunities and risks that arise from each group's distinct competencies and business strategies.

The Utility Group generates revenue primarily from the delivery of natural gas and electric service to its customers. The primary source of cash flow for the Utility Group results from the collection of customer bills and payment for goods and services procured for the delivery of gas and electric services. The Company segregates its regulated utility operations between a Gas Utility Services operating segment and an Electric Utility Services operating segment. The activities of, and revenues and cash flows generated by, the Nonutility Group are closely linked to the utility industry, and the results of those operations are generally impacted by factors similar to those impacting the overall utility industry. In addition, there are other operations, referred to herein as Corporate and Other, that include unallocated corporate expenses such as advertising and certain charitable contributions, among other activities.

The Company has a disclosure committee consisting of senior management as well as financial management. The committee is actively involved in the preparation and review of the Company’s SEC filings.

Results for the year ended December 31, 2016 were earnings of $211.6 million, or $2.55 per share, compared to earnings of $197.3 million, or $2.39 per share for the year ended December 31, 2015 and $166.9 million, or $2.02 per share for the year ended December 31, 2014. Results in 2014 include the operating results and the loss on the sale of Vectren Fuels, through the date of sale of August 29, 2014, when the Company exited the coal mining business. In 2014, excluding the loss on the disposition and operating results attributable to Vectren Fuels, consolidated net income for the year was $188.0 million, or $2.28 per share.

Consolidated Results Excluding the Results From Coal Mining in the Year of Disposition (See Page 27, regarding the Use of Non-GAAP Measures)

Net income and earnings per share, excluding results from Coal Mining in 2014, in total and by group, for the years ended December 31, 2016, 2015, and 2014 follow:

	Year Ended December 31,		
(In millions, except per share data)	2016	2015	2014
Net income*	$211.6	$197.3	$188.0
Attributed to:			
Utility Group	$173.6	$160.9	$148.4
Nonutility Group*	36.9	36.3	39.1
Corporate & Other	1.1	0.1	0.5
Basic EPS*	$2.55	$2.39	$2.28
Attributed to:			
Utility Group	$2.10	$1.95	$1.80
Nonutility Group*	0.44	0.44	0.47
Corporate & Other	0.01	—	0.01

*Excludes Coal Mining results in 2014

Utility Group
For the year ended December 31, 2016, the Utility Group earnings were $173.6 million, compared to $160.9 million in 2015 and $148.4 million in 2014. The improved results in 2016 compared to 2015 are largely driven by returns earned on the Indiana and

Ohio gas infrastructure investment programs and increases in large customer usage. These increases were somewhat offset by decreases in wholesale power margin due primarily to low natural gas prices and reduced generating unit availability. Results in 2016 compared to 2015 also reflect lower late fee revenue from lower natural gas prices. Improved results in 2015 compared to 2014 were also largely driven by returns earned on the Indiana and Ohio infrastructure replacement programs, however were somewhat offset by a decrease in electric margin primarily due to the favorable impacts of weather in the fourth quarter of 2014. Decreases in operating expense related to performance-based compensation and the timing of power plant maintenance costs favorably impacted earnings in 2015 compared to 2014, as did increased research and development tax credits for certain qualifying information technology assets.

Gas utility services
The gas utility segment earned $76.1 million during the year ended December 31, 2016, compared to $64.4 million in 2015 and $57.0 million in 2014. The improved results in the periods presented reflect increased returns on the Indiana and Ohio infrastructure programs as the investment in those programs continues to grow. Increased earnings in 2016 also resulted from an increase in large customer usage and continued growth in small customer count. These increases were somewhat offset by lower late fee revenue resulting from lower natural gas prices. Increased earnings in 2015 compared to 2014 resulted from increased returns on infrastructure replacement programs, growth in small customer count, and decreased performance-based compensation. The increased results in 2015 compared to 2014 were somewhat offset by the unfavorable impacts of weather on the Company's Ohio business in 2015.

Electric utility services
The electric operations earned $84.7 million during 2016, compared to $82.6 million in 2015 and $79.7 million in 2014. Results in 2016 reflect the favorable impact of weather on retail electric margin, which management estimates the after tax impact to be approximately $1.8 million. Results in 2016 also reflect increased large customer usage compared to 2015. These increases were somewhat offset by lower wholesale power margin due primarily to lower market pricing from the low natural gas price environment and reduced generating unit availability as a result of maintenance outages encountered in 2016. Lower operating expenses in 2015 driven primarily by decreases in power plant maintenance costs and performance-based compensation, favorably impacted 2015 results compared to 2014.

Other utility operations
In 2016, earnings from other utility operations were $12.8 million, compared to $13.9 million in 2015 and $11.7 million in 2014. The higher earnings in 2015 were driven primarily by a lower effective income tax rate from increased research and development tax credits for certain qualifying information technology assets. Approximately $3.5 million of this increase from 2015 to 2014 was related to research and development tax credits for prior periods based on Internal Revenue Service guidance issued in 2015 that provided clarifications of internal-use software that qualifies for the credit.

Nonutility Group
Results for the Nonutility Group were earnings of $36.9 million in 2016, $36.3 million in 2015, and $18.0 million in 2014. Excluding Coal Mining results in 2014, the year of disposition, the Nonutility Group earned $39.1 million in 2014. Results in the periods presented reflect an increase in earnings from Energy Services from increased revenues and margin. Results also reflect an increase in earnings from Infrastructure Services in the distribution services area as gas utilities across the country continue to make significant investments in gas infrastructure systems. Lower results from the transmission business are due largely to fewer transmission maintenance projects being awarded and lower margin on those awarded contracts. While the transmission business has been challenged throughout 2015 and 2016, results in 2016 were favorably impacted by revenues related to, among other projects, a larger project where work commenced in the third quarter of 2016 and is expected to be completed in the first quarter of 2017. Further, an approximate 150 mile, $150 million project is underway in 2017 that will aid in achieving earnings goals during this period of less maintenance focused work for the transmission business.

Dividends

Dividends declared for the year ended December 31, 2016 were $1.62 per share, compared to $1.54 per share in 2015 and $1.46 per share in 2014. In December 2016, the Company's board of directors increased its quarterly dividend to $0.42 per share from $0.40 per share. The increase marks the 57th consecutive year Vectren and predecessor companies have increased annual dividends paid.

Use of Non-GAAP Performance Measures and Per Share Measures

Results Excluding Coal Mining
This discussion and analysis contains non-GAAP financial measures that exclude the results related to Coal Mining in 2014, the year of disposition.

Management uses consolidated net income, consolidated earnings per share, and Nonutility Group net income (loss), excluding the results from Coal Mining in 2014, to evaluate its results. Coal Mining results that are excluded from the GAAP measures are inclusive of holding company costs (corporate allocations, interest and taxes). Management believes analyzing underlying and ongoing business trends is aided by the removal of Coal Mining results and the rationale for using such non-GAAP measures is that the Company has now exited the coal mining business. Management believes this presentation provides the best representation of the overall results of the ongoing operations.

A material limitation associated with the use of these measures is that measures excluding Coal Mining results does not include all activity recognized in accordance with GAAP. Management compensates for this limitation by prominently displaying a reconciliation of these non-GAAP performance measures to their closest GAAP performance measures. This display also provides financial statement users the option of analyzing results as management does or by analyzing GAAP results.

Contribution to Vectren's basic EPS
Per share earnings contributions of the Utility Group, Nonutility Group excluding Coal Mining results in 2014, and Corporate and Other are presented and are non-GAAP measures. Such per share amounts are based on the earnings contribution of each group included in the Company’s consolidated results divided by the Company’s basic average shares outstanding during the period. The earnings per share of the groups do not represent a direct legal interest in the assets and liabilities allocated to the groups; instead they represent a direct equity interest in the Company's assets and liabilities as a whole. These non-GAAP measures are used by management to evaluate the performance of individual businesses. In addition, other items giving rise to period over period variances, such as weather, may be presented on an after tax and per share basis. These amounts are calculated at a statutory tax rate divided by the Company’s basic average shares outstanding during the period. Accordingly, management believes these measures are useful to investors in understanding each business’ contribution to consolidated earnings per share and in analyzing consolidated period to period changes and the potential for earnings per share contributions in future periods. Per share amounts of the Utility Group and the Nonutility Group are reconciled to the GAAP financial measure of basic EPS by combining the two. Any resulting differences are attributable to results from Corporate and Other operations. The non-GAAP financial measures disclosed by the Company should not be considered a substitute for, or superior to, financial measures calculated in accordance with GAAP, and the financial results calculated in accordance with GAAP.

The following table reconciles consolidated net income, consolidated basic EPS, and Nonutility Group net income to those results excluding Coal Mining results in 2014.

	Twelve Months Ended December 31, 2014		
(In millions, except EPS)	GAAP Measure	Exclude Coal Mining Losses	Non-GAAP Measure
Consolidated Net Income	$166.9	$ 21.1	$ 188.0

Basic EPS	$2.02	$ 0.26	$ 2.28
Nonutility Group Net Income	$18.0	$ 21.1	$ 39.1

Detailed Discussion of Results of Operations

Following is a more detailed discussion of the results of operations of the Company's Utility and Nonutility operations. The detailed results of operations for these groups are presented and analyzed before the reclassification and elimination of certain intersegment transactions necessary to consolidate those results into the Company's Consolidated Statements of Income.

Results of Operations of the Utility Group

The Utility Group is composed of Utility Holdings' operations, which consists of the Company's regulated utility operations and other operations that provide information technology and other support services to those regulated operations. Regulated operations consist of a natural gas distribution business and an electric transmission and distribution business. The natural gas distribution business provides natural gas distribution and transportation services to nearly two-thirds of Indiana and about 20 percent of Ohio, primarily in the west-central area. The electric transmission and distribution business provides electric distribution services primarily to southwestern Indiana, and its power generating and wholesale power operations. In total, these regulated operations supply natural gas and/or electricity to over one million customers. Utility Group operating results before certain intersegment eliminations follow:

	Year Ended December 31,		
(In millions, except per share data)	2016	2015	2014
OPERATING REVENUES			
Gas utility	$771.7	$792.6	$944.6
Electric utility	605.8	601.6	624.8
Other	0.3	0.3	0.3
Total operating revenues	1,377.8	1,394.5	1,569.7
OPERATING EXPENSES			
Cost of gas sold	266.7	305.4	468.7
Cost of fuel & purchased power	183.6	187.5	201.8
Other operating	333.6	339.1	354.5
Depreciation & amortization	219.1	208.8	203.1
Taxes other than income taxes	58.3	57.1	60.2
Total operating expenses	1,061.3	1,097.9	1,288.3
OPERATING INCOME	316.5	296.6	281.4
Other income - net	26.3	18.7	16.8
Interest expense	69.7	66.3	66.6
INCOME BEFORE INCOME TAXES	273.1	249.0	231.6
Income taxes	99.5	88.1	83.2
NET INCOME	$173.6	$160.9	$148.4
CONTRIBUTION TO VECTREN BASIC EPS	$2.10	$1.95	$1.80

The Regulatory Environment

Gas and electric operations are regulated by the IURC, with regard to retail rates and charges, terms of service, accounting matters, financing, and certain other operational matters specific to its Indiana customers (the operations of SIGECO and Indiana Gas). The retail gas operations of VEDO are subject to regulation by the PUCO.

In the Company's two Indiana natural gas service territories, normal temperature adjustment (NTA) and decoupling mechanisms largely mitigate the effect that would otherwise be caused by variations in volumes sold to residential and commercial customers due to weather and changing consumption patterns. Similar usage risks in Ohio are diminished by a straight fixed variable rate design for the Company's residential customers. In addition to these mechanisms, the commissions have authorized gas infrastructure replacement programs in all natural gas service territories, which allow for recovery of these investments outside of a base rate case proceeding. Further, rates charged to natural gas customers in Indiana contain a gas cost adjustment (GCA) clause and electric rates contain a fuel adjustment clause (FAC). Both of these cost tracker mechanisms allow for the timely adjustment in charges to reflect changes in the cost of gas and cost for fuel. The Company utilizes similar mechanisms for other material operating costs, which allow for changes in revenue outside of a base rate case. Primarily as a result of rate mechanisms, the Company's last increase in base rates was 2011 for its electric business and 2009 for its gas business.

Rate Design Strategies

Sales of natural gas and electricity to residential and commercial customers are largely seasonal and are impacted by weather. Trends in the average consumption among natural gas residential and commercial customers have tended to decline as more efficient appliances and furnaces are installed, and as the Company’s utilities have implemented conservation programs. In the Company’s two Indiana natural gas service territories, normal temperature adjustment (NTA) and decoupling mechanisms largely mitigate the effect that would otherwise be caused by variations in volumes sold to these customers due to weather and changing consumption patterns. The Ohio natural gas service territory has a straight fixed variable rate design for its residential customers. This rate design, which was fully implemented in February 2010, mitigates approximately 90 percent of the Ohio service territory’s weather risk and risk of decreasing consumption specific to its small customer classes.

In all natural gas service territories, the commissions have authorized bare steel and cast iron replacement programs. In Indiana, state laws were passed in 2012 and 2013 that expand the ability of utilities to recover, outside of a base rate proceeding, certain costs of federally mandated projects and other significant gas distribution and transmission infrastructure replacement investments. Legislation was passed in 2011 in Ohio that supports the investment in other capital projects, allowing the utility to defer the impacts of these investments until its next base rate case. The Company has received approval to implement these mechanisms in both states.

SIGECO’s electric service territory currently recovers certain transmission investments outside of base rates. The electric service territory has neither an NTA nor a decoupling mechanism; however, rate designs provide for a lost margin recovery mechanism that works in tandem with conservation initiatives.

Tracked Operating Expenses

Gas costs and fuel costs incurred to serve Indiana customers are two of the Company’s most significant operating expenses. Rates charged to natural gas customers in Indiana contain a gas cost adjustment clause (GCA). The GCA clause allows the Company to timely charge for changes in the cost of purchased gas, inclusive of unaccounted for gas expense based on actual experience and subject to caps that are based on historical experience. Electric rates contain a fuel adjustment clause (FAC) that allows for timely adjustment in charges for electric energy to reflect changes in the cost of fuel. The net energy cost of purchased power, subject to an approved variable benchmark based on The New York Mercantile Exchange (NYMEX) natural gas prices, is also timely recovered through the FAC.

GCA and FAC procedures involve periodic filings and IURC hearings to establish price adjustments for a designated future period. The procedures also provide for inclusion in later periods of any variances between actual recoveries representing the estimated costs and actual costs incurred. Since April 2010, the Company has not been the supplier of natural gas in its Ohio territory.

The IURC has also applied the statute authorizing GCA and FAC procedures to reduce rates when necessary to limit net operating income to a level authorized in its last general rate order through the application of an earnings test. In the periods presented, the Company has not been impacted by the earnings test.

In Indiana, gas pipeline integrity management operating costs, costs to fund energy efficiency programs, MISO costs, and the gas cost component of uncollectible accounts expense based on historical experience are recovered by mechanisms outside of typical base rate recovery. In addition, certain operating costs, including depreciation associated with federally mandated investments, gas distribution and transmission infrastructure replacement investments, and regional electric transmission assets not in base rates are also recovered by mechanisms outside of typical base rate recovery.

In Ohio, expenses such as uncollectible accounts expense, costs associated with exiting the merchant function, and costs associated with the infrastructure replacement program and other gas distribution capital expenditures are subject to recovery outside of base rates.

Revenues and margins in both states are also impacted by the collection of state mandated taxes, which primarily fluctuate with gas and fuel costs.

Base Rate Orders
SIGECO's electric territory received an order in April 2011, with rates effective May 2011, and its gas territory received an order and implemented rates in August 2007. Indiana Gas received an order and implemented rates in February 2008, and VEDO received an order in January 2009, with implementation in February 2009. The orders authorize a return on equity ranging from 10.15 percent to 10.40 percent. The authorized returns reflect the impact of rate design strategies that have been authorized by these state commissions.

See the Rate and Regulatory Matters section of this discussion and analysis for more specific information on significant proceedings involving the Company's utilities over the last three years.

Utility Group Margin

Throughout this discussion, the terms Gas utility margin and Electric utility margin are used. Gas utility margin is calculated as Gas utility revenues less the Cost of gas sold. Electric utility margin is calculated as Electric utility revenues less Cost of fuel & purchased power. The Company believes Gas utility and Electric utility margins are better indicators of relative contribution than revenues since gas prices and fuel and purchased power costs can be volatile and these are generally collected on a dollar-for-dollar basis from customers.

In addition, the Company separately reflects regulatory expense recovery mechanisms within Gas utility margin and Electric utility margin. These amounts represent dollar-for-dollar recovery of other operating expenses. The Company utilizes these approved regulatory mechanisms to recover variations in operating expenses from the amounts reflected in base rates and are generally expenses that are subject to volatility. Following is a discussion and analysis of margin generated from regulated utility operations.

Gas utility margin
Gas utility margin and throughput by customer type follows:

	Year Ended December 31,		
(In millions)	2016	2015	2014
Gas utility revenues	$771.7	$792.6	$944.6
Cost of gas sold	266.7	305.4	468.7
Total gas utility margin	$505.0	$487.2	$475.9
Margin attributed to:			
Residential & commercial customers	$385.9	$360.8	$347.4
Industrial customers	67.1	61.4	59.3
Other	7.4	9.3	11.1
Regulatory expense recovery mechanisms	44.6	55.7	58.1
Total gas utility margin	$505.0	$487.2	$475.9
Sold & transported volumes in MMDth attributed to:			
Residential & commercial customers	97.2	104.9	122.6
Industrial customers	127.0	125.3	116.6
Total sold & transported volumes	224.2	230.2	239.2

Gas utility margins were $505.0 million for the year ended December 31, 2016, and compared to 2015, increased $17.8 million. Margin increased $25.9 million from returns on infrastructure replacement programs in Indiana and Ohio compared to 2015. Customer margin also increased $2.7 million from small customer growth and $3.0 million from large customer usage compared to 2015. With rate designs that substantially limit the impact of weather on margin, heating degree days that were 93 percent of normal in Ohio and 84 percent of normal in Indiana during 2016, compared to 95 percent of normal in Ohio and 88 percent of normal in Indiana during 2015, had only a slight unfavorable impact on small customer margin. However, warmer weather did decrease sold and transported volumes which contributed to lower regulatory expense recovery margin and a corresponding decrease in operating expenses. Regulatory expense recovery margin decreased $11.1 million compared to 2015. Results in 2016 also reflect lower miscellaneous margin largely driven by a decrease in late fee revenue as a result of lower gas prices.

Gas utility margins were $487.2 million for the year ended December 31, 2015, and compared to 2014, increased $11.3 million. Margin increased from returns on infrastructure replacement programs in Indiana and Ohio of $14.1 million compared to 2014. Customer margin also increased $1.5 million compared to 2014 from small customer growth. While warmer weather had only a slight unfavorable impact on small customer margin, it did decrease sold and transported volumes, resulting in lower regulatory expense recovery margin and a corresponding decrease in operating expenses. Regulatory expense recovery margin decreased $2.4 million compared to 2014.

Electric utility margin (Electric utility revenues less Cost of fuel & purchased power)
Electric utility margin and volumes sold by customer type follows:

	Year Ended December 31,		
(In millions)	2016	2015	2014
Electric utility revenues	$605.8	$601.6	$624.8
Cost of fuel & purchased power	183.6	187.5	201.8
Total electric utility margin	$422.2	$414.1	$423.0
Margin attributed to:			
Residential & commercial customers	$261.2	$258.6	$260.8
Industrial customers	112.1	109.7	111.2
Other	5.8	4.5	5.5
Regulatory expense recovery mechanisms	13.7	9.6	11.6
Subtotal: retail	$392.8	$382.4	$389.1
Wholesale power & transmission system margin	29.4	31.7	33.9
Total electric utility margin	$422.2	$414.1	$423.0
Electric volumes sold in GWh attributed to:			
Residential & commercial customers	2,729.0	2,714.4	2,762.3
Industrial customers	2,722.3	2,721.5	2,804.6
Other customers	22.9	22.2	22.6
Total retail volumes sold	5,474.2	5,458.1	5,589.5

Retail

Electric retail utility margins were $392.8 million for the year ended December 31, 2016 and, compared to 2015, increased by $10.4 million. Electric results, which are not protected by weather normalizing mechanisms, reflect a $3.0 million increase from weather in small customer margin as cooling degree days were 125 percent of normal in 2016 compared to 111 percent of normal in 2015. As energy conservation initiatives continue, the Company's lost revenue recovery mechanism related to electric conservation programs contributed increased margin of $2.4 million compared to the prior year, however was offset by a decrease in small customer usage of $1.2 million. Results also reflect an increase in large customer usage of $2.2 million largely driven by timing of customer plant maintenance resulting in lower customer throughput in 2015. Margin from regulatory expense recovery mechanisms increased $4.1 million as operating expenses associated with the electric conservation programs increased.

Electric retail utility margins were $382.4 million for the year ended December 31, 2015 and, compared to 2014, decreased by $6.7 million. Electric results reflect a $3.6 million decrease from weather in small customer margin as heating degree days were 88 percent of normal in 2015 compared to 107 percent of normal in 2014. While cooling degree days were 111 percent of normal in 2015 compared to 104 percent of normal in 2014, the increase in margin resulting from the increase in cooling degree days only partially offset the large decrease caused by the warmer winter in 2015. As energy conservation initiatives continue, the Company's lost revenue recovery mechanism related to electric conservation programs contributed increased margin of $0.7 million compared to the prior year. Results also reflect a decrease in large customer usage of $1.5 million largely driven by timing of customer plant maintenance resulting in lower customer throughput. Margin from regulatory expense recovery mechanisms decreased $2.0 million as operating expenses associated with the electric conservation programs decreased.

On December 3, 2013, SABIC Innovative Plastics (SABIC), a large industrial utility customer of the Company, announced its plans to build a cogeneration (cogen) facility in order to generate power to meet a significant portion of its ongoing power needs.

Electric service was provided to SABIC by the Company under a long-term contract that expired on May 2, 2016. At that date, SABIC became a tariff customer. The cogen facility was operational as of January 1, 2017 and is expected to provide approximately 85 MW of capacity. The Company will continue to provide all of SABIC's power requirements above the approximate 85 MW capacity of the cogen as well as backup power under approved tariff rates.

Margin from Wholesale Electric Activities

The Company earns a return on electric transmission projects constructed by the Company in its service territory that meet the criteria of the MISO's regional transmission expansion plans and also markets and sells its generating and transmission capacity to optimize the return on its owned assets. Substantially all off-system sales are generated in the MISO Day Ahead and Real Time markets when sales into the MISO in a given hour are greater than amounts purchased for native load. Further detail of MISO off-system margin and transmission system margin follows:

	Year Ended December 31,		
(In millions)	2016	2015	2014
MISO Transmission system margin	$25.1	$25.5	$26.1
MISO Off-system margin	4.3	6.2	7.8
Total wholesale margin	$29.4	$31.7	$33.9

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms, and other transmission system operations, totaled $25.1 million during 2016, compared to $25.5 million in 2015 and $26.1 million in 2014. The Company has invested $157.7 million in qualifying projects. The net plant balance for these projects totaled $136.8 million at December 31, 2016. These projects include an interstate 345 kV transmission line that connects the Company's A.B. Brown Generating Station to a generating station in Indiana owned by Duke Energy to the north and to a generating station in Kentucky owned by Big Rivers Electric Corporation to the south; a substation; and another transmission line. These projects earn a FERC approved equity rate of return on the net plant balance and recover operating expenses. In September 2016, the FERC issued a final order authorizing the transmission owners to receive a 10.32 percent base ROE plus, a separately approved 50 basis point adder, compared to the previously authorized 12.38 percent. The Company has reflected these outcomes in its financial statements. The 345 kV project is the largest of these qualifying projects, with a cost of $106.8 million that earned the FERC approved equity rate of return, including while under construction.

For the year ended December 31, 2016, margin from off-system sales was $4.3 million, compared to $6.2 million in 2015 and $7.8 million in 2014. The base rate changes implemented in May 2011 require that wholesale margin from off-system sales earned above or below $7.5 million per year are shared equally with customers. Results, net of sharing, for the periods presented reflect lower market pricing due primarily to low natural gas prices and in 2016, reduced unit availability. Off-system sales were 136.1 GWh in 2016, compared to 337.8 GWh in 2015, and 651.1 GWh in 2014.

Utility Group Operating Expenses

Other Operating

For the year ended December 31, 2016, Other operating expenses were $333.6 million, and compared to 2015, decreased $5.5 million. Excluding pass through costs, which accounted for $4.5 million of the decrease in operating expenses in 2016, other operating expenses decreased $1.0 million compared to 2015, primarily from a decrease in energy delivery expenses due to the colder weather in 2015 of $3.6 million. This decrease was partially offset by an increase in performance-based compensation expense.

For the year ended December 31, 2015, Other operating expenses were $339.1 million, and compared to 2014, decreased $15.4 million. The decrease in operating costs for the year is primarily due to decreases in costs not recovered directly in margin. Excluding pass through costs, other operating expenses decreased $15.3 million compared to 2014, primarily from a decrease in performance-based compensation expense of $7.1 million and decreased expenses in power plant maintenance costs of $6.9 million

Depreciation & Amortization
For the year ended December 31, 2016, Depreciation and amortization expense was $219.1 million, compared to $208.8 million in 2015 and $203.1 million in 2014. Results in the periods presented reflect increased utility plant investments placed into service primarily related to gas infrastructure programs in Indiana and Ohio.

Taxes Other Than Income Taxes
Taxes other than income taxes increased $1.2 million in 2016 compared to 2015 and decreased $3.1 million in 2015 compared to 2014. Fluctuations in the periods presented are driven by changes in gas costs and thus fluctuations in revenues and related revenue taxes as well as changes in property taxes.

Other Income-Net
Other income-net reflects income of $26.3 million in 2016, compared to $18.7 million in 2015 and $16.8 million in 2014. Results are primarily driven by increased allowance for funds used during construction (AFUDC) of approximately $4.2 million in 2016 compared to 2015 and $4.7 million in 2015 compared to 2014. The increased AFUDC in the periods presented is driven by increased capital expenditures related to gas utility infrastructure replacement investments.

Income Taxes
For the year ended December 31, 2016, Utility Group federal and state income taxes were $99.5 million, compared to $88.1 million in 2015 and $83.2 million in 2014. While income taxes increased primarily due to increased income in 2016, the effective income tax rate in 2016 was also an increase from 2015 due to research and development tax credits in 2015.

Gas Rate and Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement
The Company monitors and maintains its natural gas distribution system to ensure natural gas is delivered in a safe and efficient manner. The Company's natural gas utilities are currently engaged in programs to replace bare steel and cast iron infrastructure and other activities in both Indiana and Ohio to mitigate risk, improve the system, and comply with applicable regulations, many of which are the result of federal pipeline safety requirements. Laws passed in both Indiana and Ohio provide utilities the opportunity to timely recover costs of federally mandated projects and other infrastructure improvement projects outside of a base rate proceeding.

Indiana Senate Bill 251 (Senate Bill 251) provides a framework to recover 80 percent of federally mandated costs through a periodic rate adjustment mechanism outside of a general rate case. Such costs include a return on the federally mandated capital investment, based on the overall rate of return most recently approved by the IURC, along with recovery of depreciation and other operating costs associated with these mandates. The remaining 20 percent of those costs is deferred for future recovery in the utility's next general rate case.

Indiana Senate Bill 560 (Senate Bill 560) supplements Senate Bill 251 described above, and provides for cost recovery outside of a base rate proceeding for projects that either improve electric and gas system reliability and safety or are economic development projects that provide rural areas with access to gas service. Provisions of the legislation require that, among other things, requests for recovery include a seven-year project plan. Once the plan is approved by the IURC, 80 percent of such costs are eligible for current recovery using a periodic rate adjustment mechanism. Recoverable costs include a return on the investment that reflects the current capital structure and associated costs, with the exception of the rate of return on equity, which remains fixed at the rate determined in the Company's last rate case. Recoverable costs also include recovery of depreciation and other operating expenses. The remaining 20 percent of project costs are deferred and recovered in the utility’s next general rate case, which must be filed before the expiration of the seven-year plan. The adjustment mechanism is capped at an annual increase in retail revenues of no more than two percent.

Ohio House Bill 95 (House Bill 95) permits a natural gas utility to apply for recovery of much of its capital expenditure program. This legislation also allows for the deferral of costs, such as depreciation, property taxes, and debt-related post-in-service carrying costs until recovery is approved by the PUCO.

Indiana Recovery and Deferral Mechanisms
The Company's Indiana natural gas utilities received Orders in 2008 and 2007 associated with the most recent base rate cases. These Orders authorized the deferral of financial impacts associated with bare steel and cast iron replacement activities. The Orders provide for the deferral of depreciation and post-in-service carrying costs on qualifying projects totaling $20 million annually at Indiana Gas and $3 million annually at SIGECO. The debt-related post-in-service carrying costs are currently recognized in the Consolidated Statements of Income. The recording of post-in-service carrying costs and depreciation deferral is limited by individual qualifying project to three years after being placed into service at SIGECO and four years after being placed into service at Indiana Gas. At December 31, 2016 and December 31, 2015, the Company has regulatory assets totaling $21.9 million and $19.9 million, respectively, associated with the deferral of depreciation and debt-related post-in-service carrying cost activities. Beginning in 2014, all bare steel and cast iron replacement activities are now part of the Company’s seven-year capital investment plan discussed below.

Requests for Recovery under Indiana Regulatory Mechanisms
In August 2014, the IURC issued an Order approving the Company’s seven-year capital infrastructure replacement and improvement plan (the Plan), beginning in 2014, and the proposed accounting authority and recovery. Compliance projects and other infrastructure improvement projects were approved pursuant to Senate Bill 251 and 560, respectively. As provided in the two laws, the Order approved semi-annual filings for rate recovery of 100 percent of the costs, inclusive of return, related to these capital investments and operating expenses, with 80 percent of the costs, including a return, recovered currently via an approved tracking mechanism and 20 percent of the costs deferred and recovered in the Company’s next base rate proceeding. In addition, the Order established guidelines to annually update the seven-year capital investment plan. Finally, the Order approved the Company’s proposal to recover eligible costs assigned to the residential customer class via a fixed monthly charge per residential customer.

In March 2016, the IURC issued an Order re-approving approximately $890 million of the Company’s gas infrastructure modernization projects requested in the third update of the Plan, and approving the inclusion in rates of actual investments made through June 30, 2015. While most of the proposed capital spend has been approved as proposed, approximately $80 million of projects were not approved for recovery through the mechanisms pursuant to these filings. Specifically, Vectren proposed to add a new project to its Plan pursuant to Senate Bill 560 totaling approximately $65 million. The project, which consists of a 20-mile transmission line and other related investments required to support industrial customer growth and ongoing system reliability in the Lafayette, Indiana area, as well as allows the Company to further diversify its gas supply portfolio via access to shale gas in the Marcellus and Utica reserves, was excluded for recovery under the Plan. The IURC stated because the project was not in the original plan filed in 2013, it does not qualify for cost recovery under this law. In the Order, the IURC did pre-approve the project for rate base inclusion upon the filing of the next base rate case. The Company believes such plan updates should be expected to accommodate new projects that emerge during the term of the plan as ongoing risk assessments determine new projects are required. The Company filed an appeal of the March 2016 Order on April 29, 2016 to challenge the IURC's finding which limits the scope of the Plan updates. The outcome of the appeal is expected in the first half of 2017.

Subsequent to the March 2016 Order, the Company has received two additional Orders approving plan investments. On June 29, 2016, the IURC issued an Order approving the inclusion in rates of investments made from July 2015 to December 2015. On January 25, 2017 the IURC issued an Order (January 2017 Order) approving the inclusion in rates of investments made from January 2016 to June 2016. Through the January 2017 Order, approximately $338 million of the approved capital investment plan has been incurred and included for recovery. The January 2017 Order also approved the Company's plan update, which is now $950 million through 2020. The plan increase of $60 million is due to additional investment related to pipeline safety and compliance requirements under Senate Bill 251.

At December 31, 2016 and December 31, 2015, the Company has regulatory assets related to the Plan totaling $51.1 million and $28.6 million, respectively.

Ohio Recovery and Deferral Mechanisms

The PUCO Order approving the Company's 2009 base rate case in the Ohio service territory authorized a distribution replacement rider (DRR). The DRR's primary purpose is recovery of investments in utility plant and related operating expenses associated with replacing bare steel and cast iron pipelines, as well as certain other infrastructure investments. This rider is updated annually for qualifying capital expenditures and allows for a return on those capital expenditures based on the rate of return approved in the 2009 base rate case. In addition, deferral of depreciation and the ability to accrue debt-related post-in-service carrying costs is also allowed until the related capital expenditures are included in the DRR. The Order also initially established a prospective bill impact evaluation on the annual deferrals. On February 19, 2014, the PUCO issued an Order approving a Stipulation entered into by the PUCO Staff and the Company which provided for the extension of the DRR for the recovery of costs incurred through 2017 and expanded the types of investment covered by the DRR to include recovery of certain other infrastructure investments. The Order limits the resulting DRR fixed charge per month for residential and small general service customers to specific graduated levels through 2017. The capital expenditure plan is subject to the graduated caps on the fixed DRR monthly charge applicable to residential and small general service customers approved in the Order. In the event the Company exceeds these caps, amounts in excess can be deferred for future recovery. The remaining capital expenditure plan to be included for recovery in future DRR filings is estimated to be approximately $100 million to $120 million. The Order also approved the Company's commitment that the DRR can only be further extended as part of a base rate case. In total, the Company has made capital investments on projects that are now in-service under the DRR totaling $259.6 million as of December 31, 2016, of which $204 million has been approved for recovery under the DRR through December 31, 2015. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $24.4 million and $18.2 million at December 31, 2016 and December 31, 2015, respectively. In August 2016, the Company received approval to adjust the DRR rates, effective September 1, 2016, for recovery of investments placed in-service through December 31, 2015.

The PUCO has also issued Orders approving the Company's filings under Ohio House Bill 95. These Orders approve deferral of the Company’s Ohio capital expenditure program for items not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. Ohio House Bill 95 Orders also established a prospective bill impact evaluation on the cumulative deferrals, limiting the total deferrals at a level which would equal $1.50 per residential and small general service customer per month. At December 31, 2016 and December 31, 2015, the Company has regulatory assets totaling $41.9 million and $24.1 million, respectively, associated with the deferral of depreciation, post-in-service carrying costs, and property taxes. As of December 31, 2016, the Company's deferrals have not reached this bill impact cap. On May 2, 2016, the Company submitted its most recent annual report required under its House Bill 95 Order. This report covers the Company's capital expenditure program through calendar year 2016.

Given the extension of the DRR through 2017, as discussed above, and the continued ability to defer other capital expenses under House Bill 95, it is anticipated that the Company will file a general rate case for the inclusion in rate base of the above costs in early 2018.

Pipeline and Hazardous Materials Safety Administration (PHMSA)

In March of 2016, PHMSA published a notice of proposed rulemaking (NPRM) on the safety of gas transmission and gathering lines. The proposed rule addresses many of the remaining requirements of the 2011 Pipeline Safety Act, with a particular focus on extending integrity management rules to address a much larger portion of the natural gas infrastructure and adds requirements to address broader threats to the integrity of a pipeline system. The Company is evaluating the impact that these proposed rules will have on its integrity management programs and transmission and distribution systems. In December of 2016, PHMSA issued final rules related to integrity management for storage operations. These rules are being evaluated with efforts underway to implement the new requirements. Further, the Company reviewed the Underground Natural Gas Storage Safety Recommendations from a joint Department of Energy and PHMSA led interagency task force. PHMSA has final rules pending that address requirements related to plastic pipe, operator qualifications, valve installation and rupture detection, and incident notification. Each of these rules is expected to be published by PHMSA in 2017. Additionally, PHMSA has recently finalized a rule on excess flow valves, which will go into effect in April 2017. These rules will increase the potential for capital expenditures and increase operating and maintenance expenses. The Company believes that the cost to comply with these new rules should be recoverable using the regulatory recovery mechanisms referenced above.

Electric Rate and Regulatory Matters

Regulatory Treatment of Investments in Electric Infrastructure
On February 23, 2017, the Company filed for authority to recover costs related to its electric system modernization plan, using the mechanism allowed under Senate Bill 560. The electric system modernization plan includes investments to upgrade portions of the Company’s network of substations, transmission and distribution systems, to enhance reliability and allow the grid to accept advanced technology to improve the information and service provided to customers. The filing requests the recovery of associated capital expenditures estimated to be approximately $500 million over the seven-year period beginning in 2017. A procedural schedule has not been set in this proceeding, but under Senate Bill 560, an order is expected within 210 days of filing.

Renewable Generation Resources
On February 22, 2017, the Company also filed for authority to recover costs related to the construction of three solar projects, using the mechanism allowed under Senate Bill 29, which allows for timely recovery of costs and expenses incurred during the construction and operation of clean energy projects. These investments, presented as part of the Company’s Integrated Resource Plan (IRP) submitted in December 2016, allow the Company to add an initial 4 MW of universal solar generation, rooftop solar generation, and 1 MW of battery storage resources to its portfolio. See more information on the IRP below in Environmental and Sustainability Matters. The cost of the projects is estimated to be approximately $15 million. A procedural schedule has not been set in this proceeding, however an order is expected later in 2017.

SIGECO Electric Environmental Compliance Filing
In January 2015, the IURC issued an Order approving the Company’s request for approval of capital investments in its coal-fired generation units to comply with new EPA mandates related to mercury and air toxic standards (MATS) effective in 2015 and to address an outstanding Notice of Violation (NOV) related to sulfur trioxide emissions from the EPA. As of December 31, 2016, $30 million has been spent on equipment to control mercury in both air and water emissions, and $40 million to address the issues raised in the NOV. The Order approved the Company’s request for deferred accounting treatment, as supported by provisions under Indiana Senate Bill 29 and Senate Bill 251. The accounting treatment includes the deferral of depreciation and property tax expense related to these investments, accrual of post-in-service carrying costs, and deferral of incremental operating expenses related to compliance with these standards. The initial phase of the projects went into service in 2014, with the remaining investment going into service in 2016. As of December 31, 2016, the Company has approximately $6.9 million deferred related to depreciation and operating expense, and $2.8 million deferred related to post-in-service carrying costs.

In June 2015, Joint Appellants’ Citizens Action Coalition of Indiana, Inc., Sierra Club, Inc., and Valley Watch, Inc. (the appellants) challenged the IURC's January Order. On October 29, 2015, the Indiana Court of Appeals issued an opinion that affirmed the IURC’s findings with regard to equipment required to comply with MATS and certain national pollutant discharge elimination system rules (approximately $30 million) but remanded the case to the IURC to determine whether a certificate of public convenience and necessity (CPCN) should be issued for the equipment required by the NOV (approximately $40 million). On June 22, 2016, the IURC issued an Order granting Vectren a CPCN for the NOV-required equipment. On July 21, 2016, the appellants initiated an appeal of the IURC's June 22, 2016 Order challenging the findings made by the IURC. On February 14, 2017, the Court affirmed the IURC's June 22, 2016 Order.

SIGECO Electric Demand Side Management (DSM) Program Filing
On August 31, 2011, the IURC issued an Order approving an initial three-year DSM plan in the SIGECO electric service territory that complied with the IURC’s energy saving targets. Consistent with the Company’s proposal, the Order approved, among other items, the following: 1) recovery of costs associated with implementing the DSM Plan; 2) the recovery of a performance incentive mechanism based on measured savings related to certain DSM programs;

and 3) lost margin recovery associated with the implementation of DSM programs for large customers. On June 20, 2012, the IURC issued an Order approving a small customer lost margin recovery mechanism, inclusive of all previous deferrals. For the twelve months ended December 31, 2016, 2015, and 2014, the Company recognized electric utility revenue of $11.1 million, $10.1 million and $8.7 million, respectively, associated with this approved lost margin recovery mechanism.

On March 28, 2014, Indiana Senate Bill 340 was signed into law. The legislation allows for industrial customers to opt out of participating in energy efficiency programs and as a result of this legislation, most of the Company's eligible industrial customers have since opted out of participation in the applicable energy efficiency programs.

Indiana Senate Bill 412 (Senate Bill 412) requires electricity suppliers to submit energy efficiency plans to the IURC at least once every three years. Senate Bill 412 also permits the recovery of all program costs, including lost revenues and financial incentives associated with those plans and approved by the IURC. The Company made its first filing pursuant to this bill in June 2015, which proposed energy efficiency programs for calendar years 2016 and 2017. On March 23, 2016, the IURC issued an Order approving the Company's 2016-2017 energy efficiency programs. The Order provides for cost recovery of program and administrative expenses and includes performance incentives for reaching energy savings goals. The Order also included a lost margin recovery mechanism that now limits that recovery related to new programs to the shorter of four years or the life of the installed energy efficiency measure. Prior electric energy efficiency orders did not limit lost margin recovery in this manner. This ruling follows other recent IURC decisions implementing the same lost margin recovery limitation with respect to other electric utilities in Indiana. The Company is committed to continuing to promote and drive participation in its energy efficiency programs and has therefore appealed this lost margin recovery restriction. The Company expects a decision on its appeal in the first half of 2017.

FERC Return on Equity (ROE) Complaints

On November 12, 2013, certain parties representing a group of industrial customers filed a joint complaint with the FERC under Section 206 of the Federal Power Act against the MISO and various MISO transmission owners, including SIGECO (first complaint case). The joint parties sought to reduce the 12.38 percent ROE used in the MISO transmission owners' rates, including SIGECO's formula transmission rates, to 9.15 percent covering the refund period from November 12, 2013 through February 11, 2015 (first refund period). On September 28, 2016, the FERC issued a final order authorizing a 10.32 percent base ROE for the first refund period and prospectively through the date of the order in a second complaint case as detailed below.

A second customer complaint case was filed on February 11, 2015 covering the refund period from February 12, 2015 through May 11, 2016 (second refund period). An initial decision from the FERC administrative law judge on June 30, 2016, authorized a base ROE of 9.70 percent for the second refund period. The FERC is expected to rule on the proposed order in the second complaint case in 2017, which will authorize a base ROE for this period and prospectively from the date of the order.

Separately, on January 6, 2015, the FERC approved a MISO transmission owner joint request for an adder to the approved ROE. Under FERC regulations, transmission owners that are part of a Regional Transmission Organization (RTO) such as the MISO are authorized to earn an incentive of 50 basis points above the FERC approved ROE. The FERC deferred the implementation of this adder until the pending complaint is resolved. The adder will be applied retroactively from January 6, 2015 through May 11, 2016 and prospectively from the September 28, 2016 order in the first complaint case.

The Company has reflected these results in its financial statements. As of December 31, 2016, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $136.8 million at December 31, 2016.

Environmental and Sustainability Matters

The Company initiated its corporate sustainability program in 2012 with the publication of its initial corporate sustainability report. Since that time the Company continues to develop strategies that focus on those environmental, social and governance (ESG) factors that contribute to the long-term growth of the Company's sustainable business model. As detailed further below and in the upcoming corporate sustainability report for 2016, the Company continues to set out its plans, among other things, to upgrade and diversify its generation portfolio. The Company’s sustainability policies and efforts, and in particular its policies and procedures designed to ensure compliance with applicable laws and regulations, are directly overseen by the Board’s Corporate Responsibility and Sustainability Committee, as well as vetted with the full Board of Directors. Further discussion of key goals, strategies, and governance practices can be found in the Company’s latest sustainability report at www.vectren.com/sustainability, which received core level certification from the Global Reporting Initiative.

The Company's utility operations and properties are subject to extensive environmental regulation pursuant to a variety of federal, state, and municipal laws and regulations. These environmental regulations impose, among other things, restrictions, liabilities, and obligations in connection with the storage, transportation, treatment, and disposal of hazardous substances and limit airborne emissions from electric generating facilities including particulate matter, sulfur dioxide (SO2), nitrogen oxide (NOx), and mercury, among others. Environmental legislation and regulation also requires that facilities, sites, and other properties associated with the Company's operations be operated, maintained, abandoned, and reclaimed to the satisfaction of applicable regulatory authorities. The Company's current costs to comply with these laws and regulations are significant to its results of operations and financial condition. Similar to the costs associated with federal mandates in the Pipeline Safety Law, Senate Bill 251 is also applicable to federal environmental mandates impacting SIGECO's electric operations.

Integrated Resource Planning Process

As required by the state of Indiana, the Company completed its 2016 Integrated Resource Plan (IRP) and submitted to the IURC for review on December 16, 2016. The Company anticipates the IURC will, likely in the summer of 2017, release a director’s report to the other state utilities that filed their IRPs in 2016. The state requires each electric utility to perform and submit an IRP that uses economic modeling to consider the costs and risks associated with available resource options to provide reliable electric service for the next twenty year period. During 2016, the Company held three public stakeholder meetings to gather input and feedback as well as communicate results of the IRP process as it progressed. In developing its IRP, the Company considered both the cost to continue operating its existing generation units in a manner that complies with current and anticipated future environmental requirements, as well as various resource alternatives, such as the use of energy efficiency programs and renewable resources as part of its overall generation portfolio.

Currently, the Company operates approximately 1,000 MW of coal-fired generation, 245 MW of natural gas peaking units, and 3 MW via a landfill-gas-to-electricity facility. The Company also has 80 MW of wind power through two long-term power purchase agreements and 32 MW of coal generation through its ownership in OVEC. The Company’s 2016 IRP preferred portfolio illustrates a future less reliant on coal. The twenty year plan reflects the retirement of a portion of the Company’s current coal-fired fleet, transitions a significant portion of generation to natural gas and includes new renewable energy sources, specifically universal solar. The detailed plan would introduce approximately 54 MW of universal solar installed by 2019. The plan suggests the Company will exit its joint operations of Warrick Unit 4, a 300 MW unit shared with Alcoa, by 2020. The Company would complete upgrades to its existing coal-fired Culley Unit 3, a 270-megawatt unit, to comply with federal water regulations specific to the Effluent Limitations Guidelines (ELG) around 2023 in order to keep the unit in operation. In 2024, the plan points to the retirement of coal-fired AB Brown plant Units 1 & 2 along with Culley Unit 2, collectively representing 580 MW. This generation would be replaced by a newly constructed combined cycle natural gas plant, with the capability of producing approximately 890 MW by 2024. In addition, the Company intends to continue to offer energy efficiency programs annually.

The Company’s plan considered a broad range of potential resources and variables and is focused on ensuring it offers a reliable, reasonably priced generation portfolio as well as a balanced energy mix. The Company plans to finalize this generation portfolio transition plan and submit a regulatory filing, including construction timelines and costs of new generation resources, to the IURC in late 2017 to begin the generation transition process. The Company believes that all compliance costs, including cost of new generation as well as the cost of retiring generation, would be considered a federally mandated cost of providing electricity and therefore should be recoverable either from customers through Senate Bill 251 as referenced above, Senate Bill 29 used by the Company to recover its initial pollution control investments, or through other forms of rate recovery.

Coal Ash Waste Disposal, Ash Ponds and Water

Coal Combustion Residuals Rule

In December 2014, the EPA released its final Coal Combustion Residuals (CCR) rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). On April 17, 2015, the final rule was published in the Federal Register. The final rule allows beneficial reuse of ash and the majority of the ash generated by the Company’s generating plants will continue to be reused. As it relates to the CCR rule, legislation was passed in December 2016 by Congress that would provide for enforcement of the federal program by states rather than through citizen suits. Additionally, the CCR rule is currently being challenged by multiple parties in judicial review proceedings.

Under the final CCR rule, the Company is required to complete a series of integrity assessments, including seismic modeling given the Company’s facilities are located within two seismic zones, and groundwater monitoring studies to determine the remaining service life of the ponds and whether a pond must be retrofitted with liners or closed in place, with bottom ash handling conversions completed. In late 2015, using general utility industry data, the Company prepared cost estimates for the retirement of the ash ponds at the end of their useful lives, based on its interpretation of the closure alternatives contemplated in the final rule. The resulting estimates ranged from approximately $35 million to $80 million. These estimates contemplated final capping and monitoring costs of the ponds at both F.B. Culley and A.B. Brown generating stations. These rules are not applicable to the Company's Warrick generating unit, as this unit has historically been part of a larger generating station that predominantly serves an adjacent industrial facility.

Throughout 2016, the Company has continued to refine site specific estimates and now estimates the costs to be in the range of $45 million to $100 million. Significant factors impacting the resulting cost estimates include the closure time frame and the method of closure. Current estimates contemplate additional beneficial reuse of the ash, as well as implications of the Company’s preferred IRP. Ongoing analysis, the continued refinement of assumptions, or the inability to beneficially reuse the ash may result in estimated costs in excess of the current range.

As of December 31, 2016, the Company had recorded an approximate $40 million asset retirement obligation (ARO). The recorded ARO reflects the present value of the approximate $45 million in estimated costs in the range above. These assumptions and estimations are subject to change in the future and could materially impact the amount of the estimated ARO.

In order to maintain current operations of the ponds, the Company has spent approximately $17 million on the reinforcement of the ash pond dams and other operational changes in 2016 to meet the more stringent 2,500 year seismic event structural and safety standard in the CCR rule.

Effluent Limitation Guidelines (ELGs)
Under the Clean Water Act, the EPA sets technology-based guidelines for water discharges from new and existing electric generation facilities. On September 30, 2015, the EPA released final revisions to the existing steam electric ELGs setting stringent technology-based water discharge limits for the electric power industry. The EPA focused this rulemaking on wastewater generated primarily by pollution control equipment necessitated by the comprehensive air regulations, specifically setting strict water discharge limits for arsenic, mercury and selenium for scrubber waste waters. The ELGs will be implemented when existing water discharge permits for the plants are renewed, with compliance activities expected to commence where operations continue, within the 2018-2023 time frame. The ELGs work in tandem with the aforementioned CCR requirements, effectively prohibiting the use of less costly lined sediment basin options for disposal of coal combustion residuals, and virtually mandate conversions to dry bottom ash handling.

The current wastewater discharge permit for the A.B. Brown power plant had an expiration date of October 2016 and, for the F.B. Culley plant, a date of December 2016. The Company is continuing ongoing discussions with the state environmental agency during the first half of 2017 and anticipates final permits will be issued in the second quarter of 2017. During the renewal process, existing permits remain in place. As part of the permit renewals, the Company requested alternate compliance dates for ELGs. Compliance with the ELGs will not be required prior to November 2018, but no later than December 31, 2023. For plants identified in the Company’s preferred IRP to be retired prior to December 31, 2023, the Company has requested those plants would not require new treatment technology. For the F.B. Culley plant, the Company has proposed a 2020 compliance date for dry bottom ash and 2023 compliance date for flue gas desulfurization wastewater. The Company anticipates acceptance of the proposed schedule.

Cooling Water Intake Structures

Section 316(b) of the Clean Water Act requires generating facilities use the "best technology available" (BTA) to minimize adverse environmental impacts on a body of water. More specifically, Section 316(b) is concerned with impingement and entrainment of aquatic species in once-through cooling water intake structures used at electric generating facilities. A final rule was issued by the EPA on May 19, 2014. The final rule does not mandate cooling water tower retrofits but requires a state level case-by-case assessment of BTA for each facility. The final rule lists seven presumptive technologies which would qualify as BTA. These technologies range from intake screen modifications to cooling water tower retrofits. Ecological and technology assessment studies must be completed prior to determining BTA for the Company's facilities. The Company is currently undertaking the required ecological studies and anticipates timely compliance in 2021-2022. To comply, the Company believes capital investments will likely be in the range of $4 million to $8 million.

Air Quality

Mercury and Air Toxics (MATS) Rule

On December 21, 2011, the EPA finalized the utility MATS rule. The MATS rule sets emission limits for hazardous air pollutants for existing and new coal-fired power plants and identifies the following broad categories of hazardous air pollutants: mercury, non-mercury hazardous air pollutants (primarily arsenic, chromium, cobalt, and selenium), and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride). The rule imposes mercury emission limits for two sub-categories of coal and proposed surrogate limits for non-mercury and acid gas hazardous air pollutants.

In July 2014, a coalition of twenty-one states, including Indiana, filed a petition with the U.S. Supreme Court seeking review of the decision of the appellate court that found the EPA appropriately based its decision to list coal and oil fired generation units as a source of the pollutants at issue solely on those pollutants' impact on public health. On June 29, 2015, the U.S. Supreme Court reversed the appellate court decision on the basis of the EPA's failure to consider costs before determining whether it was appropriate and necessary to regulate steam electric generating units under Section 112 of the Clean Air Act. The Court did not vacate the rule, but remanded the MATS rule to the appellate court for further proceedings consistent with the opinion. In April 2016, in response to the Court's remand, the EPA affirmed its earlier conclusion in a Supplemental Finding, and in June 2016, a coalition of states and other stakeholders filed challenges to the Supplemental Finding. MATS compliance was required to commence April 16, 2015, and the Company continues to operate in full compliance with the MATS rule.

Notice of Violation for A.B. Brown Power Plant

The Company received a NOV from the EPA in November 2011 pertaining to its A.B. Brown generating station. The NOV asserts when the facility was equipped with Selective Catalytic Reduction (SCR) systems, the correct permits were not obtained or the best available control technology to control incidental sulfuric acid mist was not installed. While the Company did not agree with the notice, it reached a final settlement with the EPA to resolve the NOV in December 2015.

As noted previously, on January 28, 2015, the IURC issued an Order approving the Company's request for approval of capital investments on its coal-fired generation units to comply with new EPA mandates related to MATS effective in 2015 and to address the outstanding NOV. The total investment was $70 million of which $30 million was spent to control mercury in both air and water emissions, and the remaining investment was made to address the issues raised in the NOV.

In June 2015, Joint Appellants' Citizens Action Coalition of Indiana, Inc., Sierra Club, Inc., and Valley Watch, Inc. (the appellants) challenged the IURC's January Order. On October 29, 2015, the Indiana Court of Appeals issued an opinion that affirmed the IURC's findings with regard to equipment required to comply with MATS and certain national pollutant discharge elimination system rules (approximately $30 million) but remanded the case to the IURC to determine whether a certificate of public convenience and necessity (CPCN) should be issued for the equipment required by the NOV (approximately $40 million). On June 22, 2016, the IURC issued an Order granting Vectren a CPCN for the NOV-required equipment. On July 21, 2016, the appellants initiated an appeal of the IURC's June 22, 2016 Order challenging the findings made by the IURC. On February 14, 2017, the Court affirmed the IURC's June 22, 2016 Order.

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Ozone NAAQS
On November 26, 2014, the EPA proposed to tighten the current National Ambient Air Quality Standard (NAAQS) for ozone from the current standard of 75 parts per billion (ppb) to a level with the range of 65 to 70 ppb. On October 1, 2015, the EPA finalized a new NAAQS for ozone at the high end of the range, or 70 ppb. On September 16, 2016, Indiana submitted its initial determination to the EPA recommending that counties in southwest Indiana, specifically Vanderburgh, Posey and Warrick, be declared in attainment of the new more stringent ozone standard based upon air monitoring data from 2014-2016. The EPA is expected to make final determinations as to whether a region is in attainment for the new NAAQS in 2017. While it is possible that counties in southwest Indiana could be declared in non-attainment with the new standard, and thus could have an effect on future economic development activities in the Company's service territory, the Company does not anticipate any significant compliance cost impacts from the determination given its previous investment in SCR technology for NOx control on its units. In September 2016, the EPA finalized a supplement to the Cross State Air Pollution Rule (CSAPR) that requires further NOx reductions during the ozone season (May - September). The Company is positioned to comply with these NOx reduction requirements through its current investment in SCR technology.

One Hour SO2 NAAQS
On February 16, 2016, the EPA notified states of the commencement of a 120 day consultation period between the state and the EPA with respect to the EPA's recommendations for new non-attainment designations for the 2010 One Hour SO2 NAAQS. Identified on the list was Posey County, Indiana, where the Company's A.B. Brown Generating Station is located. While the Company is in compliance with all applicable SO2 limits in its permits, the Company reached an agreement with the state of Indiana on voluntary measures that the Company was able to implement without significant incremental costs to ensure that Posey County remains in attainment with the 2010 One Hour SO2 NAAQS. The Company's coal-fired generating fleet is 100 percent scrubbed for SO2 and 90 percent controlled for NOx.

Climate Change

Vectren remains committed to responsible environmental stewardship and conservation efforts. The preferred IRP, as submitted to the IURC in December 2016, is a balanced approach toward environmental stewardship and conservation goals, supplying service at a reasonable cost, and operating in compliance with water, air and solid waste regulations. The preferred IRP would result in a 60 percent reduction in carbon emissions from 2005 to 2024 and assumed the Clean Power Plan, as described below, was in place beginning in 2024. While the ultimate fate of the CPP regulation is unknown given the legal challenges it faces and recent statements from the new U.S. Administration, the Company has prepared the IRP as a long term plan that performs well in both high and low regulatory environments.

Ultimately if a national climate change policy is implemented, the Company believes it should have the following elements:

- An inclusive scope that involves all sectors of the economy and sources of greenhouse gases, and recognizes early actions and investments made to mitigate greenhouse gas emissions;
- Provisions for enhanced use of renewable energy sources as a supplement to baseload generation including effective energy conservation, demand side management, and generation efficiency measures;
- Inclusion of incentives for research and development and investment in advanced clean coal technology; and
- A strategy supporting alternative energy technologies and biofuels and continued increase in the domestic supply of natural gas and oil to reduce dependence on foreign oil.

Based on data made available through the Electronic Greenhouse Gas Reporting Tool (e-GRRT) maintained by the EPA, the Company’s direct CO2 emissions from its fossil fuel electric generation that report under the Acid Rain Program were less than one half of one percent of all emissions in the United States from similar sources. Emissions from other Company operations, including those from its natural gas distribution operations and the greenhouse gas emissions the Company is required to report on behalf of its end use customers, are similarly available through the EPA's e-GRRT database and reporting tool.

Current Initiatives to Increase Conservation & Reduce Emissions

The Company is committed to a policy that reduces greenhouse gas emissions and conserves energy usage. Evidence of this commitment includes:

- Since 2005 and through 2015, the Company has achieved a reduction in emissions of CO_2 of 31 percent (on a tonnage basis) through the retirement of F.B. Culley Unit 1, expiration of municipal contracts, electric conservation, the addition of renewable generation, and the installation of more efficient dense pack turbine technology.
- Focusing the Company’s mission statement and purpose on corporate sustainability and the need to help customers conserve and manage energy costs. Vectren's annual sustainability report received Core level certification by the Global Reporting Initiative and demonstrates the Company's commitment to sustainability and transparency in operations. The Company's latest sustainability report can be found at www.vectren.com/sustainability;
- Implementing home and business energy efficiency initiatives in the Company’s Indiana and Ohio gas utility service territories such as offering rebates on high efficiency furnaces, programmable thermostats, and insulation and duct sealing;
- Implementing home and business energy efficiency initiatives in the electric service territory such as rebate programs on central air conditioning units, LED lighting, home weatherization and energy audits;
- Building a renewable energy portfolio to complement base load generation in advance of mandated renewable energy portfolio standards;
- Evaluating potential carbon requirements with regard to new generation, other fuel supply sources, and future environmental compliance plans;
- Further reducing the Company’s carbon footprint by building a more sustainable vehicle fleet with lower overall fuel consumption;
- Reducing methane emissions through becoming a founding partner in the EPA Natural Gas STAR Methane Challenge Program. The Company's primary method for reducing methane emissions is through continued replacement of bare steel and cast iron gas distribution pipeline assets;
- Developing renewable energy and energy efficiency performance contracting projects through its Energy Services segment; and
- Helping energy producers install pipes that allow for more natural gas power generation and reduced gas flaring as well as serving distribution integrity management programs that reduce methane leaks, through its Infrastructure Services segment.

On August 3, 2015, the EPA released its final CPP rule which requires a 32 percent reduction in carbon emissions from 2005 levels. This results in a final emission rate goal for Indiana of 1,242 lb CO_2/MWh to be achieved by 2030. The new rule gives states the option of seeking a two-year extension from the initial deadline of September 2016 to submit a final state implementation plan (SIP). Under the CPP, states have the flexibility to include energy efficiency and other measures should they choose to implement a SIP as provided in the final rule. While states are given an interim goal (1,451 lb CO_2/MWh for Indiana), the final rule gives states the flexibility to shape their own emissions reduction over the 2022-2029 time period. The final rule was published in the Federal Register on October 23, 2015 and that action was immediately followed by litigation initiated by Indiana and 23 other states as a coalition challenging the rule. In January of 2016, the reviewing court denied the states’ and other parties requests to stay the implementation of the CPP pending completion of judicial review. On January 26, 2016, 29 states and state agencies, including the 24 state coalition referenced above, filed a request for immediate stay with the U.S. Supreme Court. On February 9, 2016, the U.S. Supreme Court granted a stay to delay the regulation while being challenged in court. Extensive oral argument was held in September. The stay will remain in place while the lower court concludes its review. Among other things, the stay delays the requirement to submit a final SIP by the original September 2016 deadline and could extend implementation to 2024.

In the event a state does not submit a SIP, the EPA also released a proposed federal implementation plan (FIP), which would be imposed on those states without an approved SIP. The proposed FIP would apply an emission rate requirement directly on generating units. Under the proposed FIP, the CO_2 emission rate limit for coal-fired units would start at 1,671 lbs CO_2/MWh in 2022 and decrease to a final emission rate cap of 1,305 lbs CO_2/MWh by 2030. While the FIP emission rate cap appears to be slightly less stringent than the state reduction goal for Indiana, the cap would apply directly to generating units and these units would not have the benefit of averaging emission rates with rates from zero-carbon sources as would be available in a SIP. Purchases of emission credits from zero-carbon sources can be made for compliance. The FIP will be subject to extensive public comments prior to finalization. Whether Indiana will file a SIP has yet to be determined. Pending that determination, the electric utilities in Indiana will continue to encourage the state's designated agency to analyze various compliance options and the possible integration into a state plan submittal.

At the time of release of the CPP, Indiana was the 5th largest carbon emitter in the nation in tons of CO_2 produced from electric generation. The Company’s share of total tons of CO_2 generated by Indiana's electric utilities has historically been less than 6 percent. Since 2005 through 2015, the Company has achieved a reduction in emissions of CO_2 of 31 percent (on a tonnage basis) through the retirement of F.B. Culley Unit 1, expiration of municipal wholesale power contracts, electric conservation, the addition of renewable generation, and the installation of more efficient dense pack turbine technology. Since emissions are further impacted by coal burn reductions and energy efficiency programs, the Company's emissions of CO_2 can vary year to year. With respect to renewable generation, in 2008 and 2009, the Company executed long-term purchase power commitments for a total of 80 MW of wind energy. The Company currently has approximately 4 percent of its electricity being provided by energy sources other than coal and natural gas, due to the long-term wind contracts and landfill gas investment. With respect to CO_2 emission rate, since 2005 through 2015, the Company has lowered its CO_2 emission rate (as measured in lbs CO_2/MWh) from 1,967 lbs CO_2/MWh to 1,922 lbs CO_2/MWh, for a reduction of 3 percent. The Company’s CO_2 emission rate of 1,922 lbs CO_2/MWh is basically the same as Indiana's average CO_2 emission rate of 1,923 lbs CO_2/MWh. The Company plans to consider these reductions in CO_2 emissions and renewable generation in future discussions with the state to develop a possible state implementation plan.

Impact of Legislative Actions & Other Initiatives is Unknown

At this time, compliance costs and other effects associated with reductions in GHG emissions or obtaining renewable energy sources remain uncertain. The Company has gathered preliminary estimates of the costs to control GHG emissions. A preliminary investigation demonstrated costs to comply would be significant, first with regard to operating expenses and later for capital expenditures as technology becomes available to control GHG emissions. However, these compliance cost estimates were based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. The Company is undertaking a detailed review of the requirements of the CPP and the proposed FIP and a review of potential compliance options. The Company will also continue to remain engaged with the Indiana legislators and regulators to assess the final rule and to develop a plan that is the least cost to its customers.

In addition to the federal programs, the United States and 194 other countries agreed by consensus to limit GHG emissions beginning after 2020 in the 2015 United Nations Framework Convention on Climate Change Paris Agreement. The United States has proposed a 26-28 percent GHG emission reduction from 2005 levels by 2025. As previously noted, since 2005 through 2015, the Company has achieved reduced emissions of CO_2 by 31 percent (on a tonnage basis). While the legislative outcome of the CPP rules remains uncertain, the Company will continue to monitor regulatory activity regarding GHG emission standards that may affect its electric generating units.

Manufactured Gas Plants

In the past, the Company operated facilities to manufacture natural gas. Given the availability of natural gas transported by pipelines, these facilities have not been operated for many years. Under current environmental laws and regulations, those that owned or operated these facilities may now be required to take remedial action if certain contaminants are found above the regulatory thresholds.

In the Indiana Gas service territory, the existence, location, and certain general characteristics of 26 gas manufacturing and storage sites have been identified for which the Company may have some remedial responsibility. A remedial investigation/ feasibility study (RI/FS) was completed at one of the sites under an agreed upon order between Indiana

Gas and the IDEM, and a Record of Decision was issued by the IDEM in January 2000. The remaining sites have been submitted to the IDEM's Voluntary Remediation Program (VRP). The Company has identified its involvement in five manufactured gas plant sites in SIGECO’s service territory, all of which are currently enrolled in the IDEM’s VRP. The Company is currently conducting some level of remedial activities, including groundwater monitoring at certain sites.

The Company has accrued the estimated costs for further investigation, remediation, groundwater monitoring, and related costs for the sites. While the total costs that may be incurred in connection with addressing these sites cannot be determined at this time, the Company has recorded cumulative costs that it has incurred or reasonably expects to incur totaling approximately $44.2 million ($23.9 million at Indiana Gas and $20.3 million at SIGECO). The estimated accrued costs are limited to the Company's share of the remediation efforts and are therefore net of exposures of other potentially responsible parties (PRP).

With respect to insurance coverage, Indiana Gas has received approximately $20.8 million from all known insurance carriers under insurance policies in effect when these plants were in operation. Likewise, SIGECO has settlement agreements with all known insurance carriers and has received approximately $15.2 million of the expected $15.8 million in insurance recoveries.

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company's utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of December 31, 2016 and December 31, 2015, approximately $2.9 million and $3.3 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

Results of Operations of the Nonutility Group

The Nonutility Group operates in two primary business areas: Infrastructure Services and Energy Services. Infrastructure Services provides underground pipeline construction and repair services. Energy Services provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects. Prior to August 29, 2014, the Company had activities in its Coal Mining business. Results include the results of Vectren Fuels through the date of sale of August 29, 2014, when the Company exited the coal mining business through the sale of Vectren Fuels. Enterprises has other legacy businesses that have investments in energy-related opportunities and services, among other investments. All of the above is collectively referred to as the Nonutility Group.

The Nonutility Group results were earnings of $36.9 million for the year ended December 31, 2016, earnings of $36.3 million for the year ended December 31, 2015 and earnings of $18.0 million for the year ended December 31, 2014. Nonutility Group earnings, excluding the results from Coal Mining in 2014, follow. See page 27 for a reconciliation of Non-GAAP performance measures in 2014.

	Year Ended December 31,		
(In millions, except per share amounts)	2016	2015	2014
NET INCOME*	$36.9	$36.3	$39.1
CONTRIBUTION TO VECTREN BASIC EPS*	$0.44	$0.44	$0.47
NET INCOME (LOSS) ATTRIBUTED TO:			
Infrastructure Services	$25.0	$29.7	$43.1
Energy Services	12.5	7.3	(3.2)
Other Businesses	(0.6)	(0.7)	(0.8)

*Excludes Coal Mining Results in 2014

Infrastructure Services

Infrastructure Services provides underground pipeline construction and repair services through wholly owned subsidiaries Miller Pipeline, LLC (Miller or Miller Pipeline) and Minnesota Limited, LLC (Minnesota Limited). Inclusive of holding company costs, earnings from Infrastructure Services' operations for the year ended December 31, 2016 were $25.0 million compared to $29.7 million in 2015, and $43.1 million in 2014.

The distribution portion of the Infrastructure Services' operation had record revenues and earnings from operations in 2016, as gas utilities across the country continued to make significant investments in gas infrastructure systems. This growth trend is expected to continue as utilities execute infrastructure programs. Lower results from the transmission business are due largely to fewer transmission maintenance projects being awarded and lower margin on awarded contracts. While the transmission business has been challenged throughout 2015 and 2016, results in 2016 were favorably impacted by revenues related to, among other projects, a larger project where work commenced in the third quarter of 2016 and is expected to be completed in the first quarter of 2017. Further, an approximate 150 mile, $150 million project is underway in 2017 that will aid in achieving earnings goals during this period of less maintenance focused work for the transmission business.

The reduction in Infrastructure Services' transmission operations is primarily reflective of a very competitive transmission pipeline maintenance environment that has reduced the number of projects awarded and has pressured margin on projects won as other contractors adjust crews and workload as some large gas and oil projects have been delayed due to the lengthening environmental and regulatory approval process. Total Infrastructure Services revenues in 2016 were $813 million, compared to revenues of $843 million in 2015 and $779 million in 2014.

Backlog represents the amount of gross revenue the Company expects to realize from work to be performed in the future on uncompleted contracts, including new contractual agreements on which work has not begun. Infrastructure Services operates primarily under two types of contracts, blanket contracts and bid contracts. Using blanket contracts, customers are not contractually committed to specific volumes of services, however the Company expects to be chosen to perform work needed by a customer in a given time frame. These contracts are typically awarded on an annual or multi-year basis. For blanket work, backlog represents an estimate of the amount of gross revenue that the Company expects to realize from work to be performed in the next twelve months on existing contracts or contracts the Company reasonably expects to be renewed or awarded based upon recent history or discussions with customers. Under bid contracts, customers are contractually committed to a specific service to be performed for a specific price, whether in total for a project or on a per unit basis. At December 31, 2016, Infrastructure Services had an estimated backlog of blanket contracts of $435 million and bid contracts of $290 million, for a total backlog of $725 million. Backlog has increased from the prior year due to the approximate 150 mile project awarded in December 2016 to be largely completed in 2017. The estimated backlog at December 31, 2015 was $475 million for blanket contracts and $190 million for bid contracts, for a total of $665 million. Estimated backlog at December 31, 2014 was $500 million for blanket contracts and $125 million for bid contracts, for a total of $625 million.

The backlog amounts above reflect estimates of revenues to be realized. Projects included in backlog can be subject to delays or cancellation as a result of regulatory requirements, adverse weather conditions, customer requirements, among other factors, which could cause actual revenue amounts to differ significantly from the estimates and/or revenues to be realized in periods other than originally expected.

The fundamental business model related to the long cycle of transmission sector repair and maintenance work remains unchanged as demand remains high due to aging infrastructure and evolving safety and reliability regulations. There are also significant new pipeline projects now totaling approximately 12,000 miles with estimated completion dates primarily through 2020 that are ultimately expected to absorb resources and equipment. The result should be a gradual increase in opportunities for pipeline maintenance work and some increase in margins as the competition for maintenance work decreases. Further, evolving safety and reliability regulations are anticipated to continue to drive demand in maintenance and integrity work. In March 2016, a notice of proposed rulemaking was published on the safety of gas transmission and gathering lines. The proposed rule addresses many of the remaining requirements from the 2011 Pipeline Safety Act and will likely lead to additional demand for pipeline maintenance and integrity work. Finally, recent comments from President Trump about increased focus on infrastructure enhancement, including actions aimed at proceeding with some large projects, further underscores the need to address the aging infrastructure and may ultimately have positive impacts on the markets in which Infrastructure Services' operates in the mid to long-term.

In 2016, the estimated depreciable lives for certain pieces of equipment at Minnesota Limited, LLC were reevaluated and extended due to a change in service life of the equipment. As a result of this evaluation, the Company extended the estimated useful life of certain pieces of equipment effective January 1 of the current year. The effect of this change in estimate was a reduction of annual depreciation expense of approximately $9.6 million in 2016 but did not have a material impact on net income as these costs are fully reflected in bids as costs to recover.

Energy Services

Energy Services provides energy performance contracting and sustainable infrastructure, such as distributed generation, renewables, and combined heat and power projects, through its wholly owned subsidiary Energy Systems Group, LLC (ESG). Inclusive of holding company costs, Energy Services’ operations were earnings of $12.5 million in 2016, $7.3 million in 2015 and a loss of $3.2 million in 2014. Energy Services achieved record revenues of $260 million in 2016, which exceeded record revenues of $200 million in 2015 and revenue of $130 million in 2014.

At December 31, 2016, the backlog of fixed price signed contracts is $234 million, compared to $226 million on December 31, 2015 and $144 million on December 31, 2014. The list of projects at December 31, 2016 where ESG has been selected and there is a high degree of confidence that the stated work will be performed, or sales funnel, remains high at $345 million. The Company's long-term view of the performance contracting and sustainable infrastructure opportunities remains strong with an expected continued national focus on energy conservation and security, renewable energy, and sustainability as power prices across the country rise and customer focus on new, efficient, clean sources of energy grows. Expected activity in the federal sector, as well as positive indications in the public sector and sustainable infrastructure business, is reflected in the strong backlog and sales funnel. In December 2015, the tax code section (Section 179D) allowing for federal tax deductions related to energy efficiency savings achieved was retroactively extended for 2015 through 2016. The impact of these tax deductions on results, net of fees and incentives, was $5.5 million in 2016, $6.1 million in 2015, and $3.7 million in 2014.

Results in 2014 reflect an after-tax gain of $8.9 million related to the reversal of the contingent consideration liability associated with the acquisition of the Federal Business Unit (FBU) from Chevron, USA (Chevron). The contingent liability was reversed due to failure to meet certain earn-out thresholds as a result of delays in closing certain projects in the sales funnel. These non-recurring earnings in 2014 were offset by an after-tax expense of $9.1 million to fund the Vectren Foundation, Inc. for an extended period. More detailed information about ESG's acquisition of FBU is included in Note 5 to the Company's Consolidated Financial Statements included in Item 8.

Inclusive in the acquisition of FBU from Chevron on April 1, 2014, were several Indefinite Delivery / Indefinite Quantity (IDIQ) contracts with federal government agencies including energy savings performance contracting (ESPC) contracts with the U.S. Department of Energy and U.S. Army Corps of Engineers. On a periodic basis, the contracts are extended and/or subject to a recompete process. The recompete process for the U.S. Army Corps of Engineers contract was completed and awarded to ESG in May of 2015. The U.S. Department of Energy IDIQ contract has been extended through the end of 2019 while the recompete process for the U.S. Department of Energy ESPC contract is currently in process, and management expects that the contract will be awarded to ESG. Anticipated completion of this process has extended into 2017.

Coal Mining

Prior to August 29, 2014, Coal Mining owned and, through its contract miners, mined and sold coal to the Company's utility operations and to third parties through its wholly owned subsidiary, Vectren Fuels. On August 29, 2014, the Company sold Vectren Fuels. Results from Coal Mining for the year ended December 31, 2014, inclusive of the loss on sale, were a loss of $21.1 million.

Other Businesses

ProLiance

The Company has an investment in ProLiance Holdings, LLC (ProLiance or ProLiance Holdings). On June 18, 2013, ProLiance Holdings exited the natural gas marketing business through the disposition of certain of the net assets, along with the long-term pipeline and storage commitments, of its energy marketing business, ProLiance Energy, LLC (ProLiance Energy) to a subsidiary of Energy Transfer Partners, ETC Marketing, Ltd (ETC). ProLiance Energy's customers included, among others, the Company's Indiana utilities as well as Citizens' utilities. The Company's remaining investment in ProLiance relates primarily to an investment in LA Storage, LLC (LA Storage). Consistent with its ownership percentage, the Company is allocated 61 percent of ProLiance's profits and losses; however, governance and voting rights remain at 50 percent for each member; and therefore, the Company accounts for its investment in ProLiance using the equity method of accounting.

At December 31, 2016, ProLiance had approximately $48.0 million of capitalization on its balance sheet, composed of $31.4 million in member's equity and $16.6 million in a note payable. The capitalization primarily supports its investment in LA Storage of $36.7 million and one other midstream asset. The Company's investment in ProLiance at December 31, 2016 totals $29.3 million and is comprised of $19.2 million of equity and a $10.1 million note receivable.

LA Storage

ProLiance Transportation and Storage, LLC (PT&S), a subsidiary of ProLiance, and Sempra Energy International, a subsidiary of Sempra Energy, through a joint venture, have a 100 percent interest in a development project for salt-cavern natural gas storage facilities known as LA Storage. PT&S is the minority member with a 25 percent interest, which it accounts for using the equity method. The project, which includes a pipeline system, is expected to include 12-19 Bcf of storage capacity, and has the potential for further expansion. This pipeline system is currently connected with several interstate pipelines, including the Cameron Interstate Pipeline operated by Sempra Pipelines & Storage, and can connect area liquefied natural gas regasification terminals to an interstate natural gas transmission system and storage facilities.

Approximately 12 Bcf of the storage, which comprises three of the four FERC certified caverns, is fully tested but additional work is required to further develop the caverns. The timing and extent of development of these caverns is dependent on market conditions, including pricing, need for storage capacity, and development of the liquefied natural gas market, among other factors. To date, development activity has been modest due to current low demand for storage facilities. The development of the storage market and related pricing are critical assumptions in the analysis of the recoverability of the investment's carrying value.

Other Businesses
Within the Nonutility business segment, there are legacy investments involved in energy-related opportunities and services and other ventures. As of December 31, 2016, remaining legacy investments included in the Other Businesses portfolio total $7.0 million. During 2015, the Company sold its investment in a commercial real estate property as well as an interest in a leveraged lease for approximate book value. At December 31, 2016, the remaining investment relates to a debt security related to the sale of commercial real estate of $5.1 million and other investments of $1.9 million.

Other Businesses results were a loss of $0.6 million in 2016, compared to a loss of $0.7 million in 2015 and a loss of $0.8 million in 2014.

Impact of Recently Issued Accounting Guidance

Revenue Recognition Guidance
In May 2014, the FASB issued new accounting guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for GAAP. The amendments in this guidance state that an entity should recognize revenue to depict the transfer of promised 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. This new guidance requires improved disclosures to help users of financial statements better understand the nature, amount, timing, and uncertainty of revenue that is recognized. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). While the Company continues to assess the standard and initial conclusions could change based on completion of that assessment, the Company preliminarily plans to adopt the guidance under the modified retrospective method.

On July 9, 2015, the FASB approved a one year deferral that became effective through an ASU in August and changed the effective date to annual reporting periods beginning after December 15, 2017, including interim periods, with early adoption permitted, but not before the original effective date of December 15, 2016.

The Company is currently assessing the impacts this guidance may have on the Consolidated Balance Sheets, Consolidated Statements of Operations, and disclosures including the ability to recognize revenue for certain contracts, and its accounting for contributions in aid of construction (CIAC). While management will continue to analyze the impact of this new standard and the related ASUs that clarify guidance in the standard, at this time, management does not believe adoption of the standard will have a significant impact on the Company's pattern of revenue recognition. The Company plans to adopt the guidance effective January 1, 2018.

Simplifying the Presentation of Debt Issuance Costs
In April 2015, the FASB issued new accounting guidance on accounting for debt issuance costs which changes the presentation of debt issuance costs in financial statements. This ASU requires an entity to present such costs in the balance sheet as a direct reduction from the related debt liability rather than as an asset. Amortization of the costs will continue to be reported as interest expense. This ASU is effective for annual reporting periods beginning after December 15, 2015. The guidance was adopted as of January 1, 2016 and has been applied retrospectively to all periods presented. The effect of the change on the December 31, 2015 balance sheet was the reclassification of $8.6 million from Regulatory assets to Long-term Debt and the reclassification of $1.3 million from Other assets to Long-term Debt. The reclassification had no material impact on the Company's financial condition, results of

operations, or cash flows as a result of the adoption.

Leases
In February 2016, the FASB issued new accounting guidance for the recognition, measurement, presentation and disclosure of leasing arrangements. This ASU requires the recognition of lease assets and liabilities for those leases currently classified as operating leases while also refining the definition of a lease. In addition, lessees will be required to disclose key information about the amount, timing, and uncertainty of cash flows arising from leasing arrangements. This ASU is effective for the interim and annual reporting periods beginning January 1, 2019, although it can be early adopted, with a modified retrospective approach for leases that commenced prior to the date of adoption. The Company is currently evaluating the standard to determine the impact it will have on the financial statements.

Stock Compensation
In March 2016, the FASB issued new accounting guidance which is intended to simplify several aspects of accounting for share-based payment transactions, including the income tax consequences. This ASU is effective for annual periods beginning after December 15, 2016, and relevant interim periods. Early application is permitted. Most of the Company's share based awards are settled via cash payments and are therefore not impacted by this standard. The Company does not anticipate adoption of the standard to have a significant impact on the financial statements.

Other Recently Issued Standards
Management believes that other recently issued standards, which are not yet effective, will not have a material impact on the Company's financial position, results of operations, or cash flows upon adoption.

Critical Accounting Policies

Management is required to make judgments, assumptions, and estimates that affect the amounts reported in the consolidated financial statements and the related disclosures that conform to accounting principles generally accepted in the United States. The footnotes to the consolidated financial statements describe the significant accounting policies and methods used in their preparation. Certain estimates are subjective and use variables that require judgment. These include the estimates to perform goodwill and other asset impairments tests and to determine pension and postretirement benefit obligations. The Company makes other estimates related to the effects of regulation that are critical to the Company’s financial results but that are less likely to be impacted by near term changes. Other estimates that significantly affect the Company’s results, but are not necessarily critical to operations, include depreciating utility and nonutility plant, valuing asset retirement obligations, and estimating uncollectible accounts, unbilled revenues, and deferred income taxes, among others. Actual results could differ from these estimates.

Impairment Review of Investments and Long-Lived Assets

The Company has both debt and equity investments in unconsolidated entities. When events occur that may cause an investment to be impaired, the Company performs both a qualitative and quantitative review of that investment and when necessary performs an impairment analysis. An impairment analysis of notes receivable usually involves the comparison of the investment’s estimated free cash flows to the stated terms of the note, or in certain cases for notes that are collateral dependent, a comparison of the collateral’s fair value to the carrying amount of the note. An impairment analysis of equity investments involves comparison of the investment’s estimated fair value to its carrying amount and an assessment of whether any decline in fair value is “other than temporary.” Fair value is estimated using market comparisons, appraisals, and/or discounted cash flow analysis.

Property, plant and equipment along with other long-lived assets are reviewed as facts and circumstances indicate that the carrying amount may be impaired. This impairment review involves the comparison of an asset’s (or group of assets’) carrying value to the estimated future cash flows the asset (or asset group) is expected to generate over a remaining life. If this evaluation were to conclude that the carrying value is impaired, an impairment charge would be recorded based on the difference between the carrying amount and its fair value (less costs to sell for assets to be disposed of by sale).

Calculating free cash flows and fair value using the above methods is subjective and requires judgment concerning growth assumptions, longevity of cash flows, and discount rates (for fair value calculations), among others.

Over the years presented, the Company has recorded charges associated with legacy commercial real estate and other investments using the methods described above.

Goodwill & Intangible Assets

The Company performs an annual impairment analysis of its goodwill, most of which resides in the Gas Utility Services operating segment, at the beginning of each year, and more frequently if events or circumstances indicate that an impairment loss may have been incurred. Impairment tests are performed at the reporting unit level. The Company has determined its Gas Utility Services operating segment to be the level at which impairment is tested as its reporting units are similar. Nonutility Group impairment testing for its Infrastructure Services and Energy Services segments are also performed at the operating segment level. An impairment test requires fair value to be estimated. The Company used a discounted cash flow model and other market based information to estimate the fair value of its Gas Utility Services, Infrastructure Services, and Energy Services operating segments, and those estimated fair values are compared to their carrying amount, including goodwill. The estimated fair value has been substantially in excess of the carrying amount in each of the last three years and therefore resulted in no impairment.

Estimating fair value using a discounted cash flow model is subjective and requires significant judgment in applying a discount rate, growth assumptions, company expense allocations, and longevity of cash flows. A 100 basis point increase in the discount rate utilized to calculate the Gas Utility Services, Infrastructure Services, and Energy Services segment fair value also would have resulted in no impairment charge.

The Company also annually tests non-amortizing intangible assets for impairment and amortizing intangible assets are tested on an event and circumstance basis. During the last three years, these tests yielded no impairment charges.

Pension & Other Postretirement Obligations

The Company estimates the expected return on plan assets, discount rate, rate of compensation increase, and future health care costs, among other inputs, and obtains actuarial estimates to assess the future potential liability and funding requirements of the Company's pension and postretirement plans. Detailed information about the assumptions the Company used to develop 2016 periodic benefit cost are included in Note 11 to the Company's Consolidated Financial Statements included in Item 8. To estimate the 2016 obligation and 2017 costs, the Company used the following weighted average assumptions: a discount rate of approximately 4.07 percent; an expected return on plan assets of 7.00 percent; a rate of compensation increase of 3.50 percent; and an inflation assumption of 2.50 percent. The discount rate was based on benchmark interest rates and expected rate of return on plan assets was determined using a building block approach.

In October 2014, the Society of Actuaries (SOA) released updated mortality estimates that reflect increased life expectancy. The Company updated its mortality assumptions to incorporate this increase in life expectancy. Accordingly, the Company updated its base mortality assumption to the SOA 2014 table as well as updated its projected mortality improvement. In October 2015 and 2016, the SOA released updated projected mortality improvement that reflect additional years of data. The Company continues to use the SOA 2014 base table and has updated to the projected mortality improvement data that was released in 2015 and 2016, respectively. These changes are reflected in the Company's benefit obligation as of December 31, 2016. Future changes in health care costs, work force demographics, interest rates, asset values or plan changes could significantly affect the estimated cost of these future benefits. Management currently estimates the pension and postretirement cost to be approximately $6.6 million in 2017.

Management estimates that a 50 basis point increase in the discount rate used to estimate retirement costs generally decreases periodic benefit cost by approximately $1.6 million.

Regulation

At each reporting date, the Company reviews current regulatory trends in the markets in which it operates. This review involves judgment and is critical in assessing the recoverability of regulatory assets as well as the ability to continue to account for its activities based on the criteria set forth in FASB guidance related to accounting for the effects of certain types of regulation. Based on the Company’s current review, it believes its regulatory assets are probable of recovery. If all or part of the Company's operations cease to meet the criteria, a write-off of related regulatory assets and liabilities could be required. In addition, the Company would be required to determine any impairment to the carrying value of its utility plant and other regulated assets and liabilities. In the unlikely event of a change in the current regulatory environment, such write-offs and impairment charges could be significant.

Financial Condition

Within the Company’s consolidated group, Utility Holdings primarily funds the short-term and long-term financing needs of the Utility Group operations, and Vectren Capital Corp (Vectren Capital) funds short-term and long-term financing needs of the Nonutility Group and corporate operations. Vectren Corporation guarantees Vectren Capital’s debt, but does not guarantee Utility Holdings’ debt. Vectren Capital’s long-term debt, including current maturities outstanding at December 31, 2016 approximated $334 million. Vectren Capital had no short-term obligations outstanding at December 31, 2016. Utility Holdings’ outstanding long-term and short-term borrowing arrangements are jointly and severally guaranteed by its wholly owned subsidiaries and regulated utilities Indiana Gas, SIGECO, and VEDO. Utility Holdings’ long-term debt and short-term obligations outstanding at December 31, 2016 approximated $996 million and $194 million, respectively. Additionally, prior to Utility Holdings’ formation, Indiana Gas and SIGECO funded their operations separately, and therefore, have long-term debt outstanding funded solely by their operations. SIGECO will also occasionally issue new tax-exempt debt to fund qualifying pollution control capital expenditures. Total Indiana Gas and SIGECO long-term debt, including current maturities, outstanding at December 31, 2016, was $384 million.

The Company’s common stock dividends are primarily funded by utility operations. Nonutility operations have demonstrated profitability and the ability to generate cash flows. These cash flows are primarily reinvested in other nonutility ventures, but are also used to fund a portion of the Company’s dividends, and from time to time may be reinvested in utility operations or used for corporate expenses.

Vectren Corporation's corporate credit rating is A-, as rated by Standard and Poor's Ratings Services (Standard and Poor's). Moody's Investors Services (Moody's) does not provide a rating for Vectren Corporation. The credit ratings of the senior unsecured debt of Utility Holdings, SIGECO, and Indiana Gas, at December 31, 2016, were A-/A2 as rated by Standard and Poor's and Moody’s, respectively. The credit ratings on SIGECO's secured debt are A/Aa3. Utility Holdings’ commercial paper had a credit rating of A-2/P-1. The current outlook of both Moody’s and Standard and Poor’s is stable. A security rating is not a recommendation to buy, sell, or hold securities. The rating is subject to revision or withdrawal at any time, and each rating should be evaluated independently of any other rating. Standard and Poor’s and Moody’s lowest level investment grade rating is BBB- and Baa3, respectively.

The Company’s consolidated equity capitalization objective is 45-55 percent of long-term capitalization. This objective may have varied, and will vary, depending on particular business opportunities, capital spending requirements, execution of long-term financing plans, and seasonal factors that affect the Company’s operations. The Company's equity to long-term capitalization ratio was 51 percent and 49 percent as of December 31, 2016 and 2015, respectively. Long-term capitalization includes long-term debt, including current maturities, as well as common shareholders’ equity.

Both long-term and short-term borrowing arrangements contain customary default provisions; restrictions on liens, sale-leaseback transactions, mergers or consolidations, and sales of assets; and restrictions on leverage, among other restrictions. Multiple debt agreements contain a covenant that the ratio of consolidated total debt to consolidated total capitalization will not exceed 65 percent. As of December 31, 2016, the Company was in compliance with all debt covenants.

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Available Liquidity

The Company's A-/A2 investment grade credit ratings have allowed it to access the capital markets as needed, and as evidenced by past financing transactions, the Company believes it will have the ability to continue to do so. The Company anticipates funding future capital expenditures and dividends principally through internally generated funds, supplemented with incremental external debt and equity financing and cash flow generated from nonutility businesses. However, management has considered access to both short-term and long-term capital markets as a significant source of funding for capital requirements as the resources required for capital investment remain uncertain for a variety of factors including, but not limited to, expanded environmental regulations, growth of the regulated business, and growth of Infrastructure Services and Energy Services. These regulations may result in the need to raise additional capital in the coming years. To the extent that events beyond the Company's control create uncertainty in capital markets, cost of capital and ability to access capital markets may be affected. Refer to 'Risk Factors' in Item 1A for a summary of future considerations.

Utility Holdings routinely seeks approval at the IURC and the PUCO for long-term financing authority at the individual utility level. This authority allows for the flexibility for each utility to issue debt and equity securities to third parties or to issue debt and equity securities to Utility Holdings and thus receive some of the proceeds from various Utility Holdings issuances to third parties on the same terms as those obtained by Utility Holdings. The majority of the long-term debt needs of the utilities is expected to be met through these debt issuances by Utility Holdings, some or all of which are then reloaned to the individual utilities. On June 15, 2016 an Order for long-term financing authority of $70 million of long-term debt and $75 million of equity financing was received from the PUCO for VEDO. This Order expires in June 2017. A request of long-term financing authority for SIGECO and Indiana Gas is pending before the IURC and an order is expected in early 2017.

Recent Company financings are explained in the discussion of financing cash flow beginning on page 55.

Consolidated Short-Term Borrowing Arrangements

At December 31, 2016, the Company had $600 million of short-term borrowing capacity, including $350 million for the Utility Group and $250 million for the wholly owned Nonutility Group and corporate operations. As reduced by borrowings currently outstanding, approximately $156 million was available for the Utility Group operations and $250 million was available for the wholly owned Nonutility Group and corporate operations. Both Vectren Capital’s and Utility Holdings’ short-term credit facilities are available through October 31, 2019. These facilities are used to supplement working capital needs and also to fund capital investments and debt redemptions.

The Company has historically funded the short-term borrowing needs of Utility Holdings’ operations through the commercial paper market but maintains the ability to use the Utility Holdings short-term borrowing facility when necessary. Following is certain information regarding these short-term borrowing arrangements.

	Utility Group Borrowings			Nonutility Group Borrowings		
(In millions)	2016	2015	2014	2016	2015	2014
As of Year End						
Balance Outstanding	$194.4	$14.5	$156.4	$—	$—	$—
Weighted Average Interest Rate	1.05 %	0.55 %	0.50 %	N/A	N/A	N/A
Annual Average						
Balance Outstanding	$59.8	$53.8	$35.6	$0.2	$24.8	$34.5
Weighted Average Interest Rate	0.71 %	0.38 %	0.34 %	1.60 %	1.33 %	1.29 %
Maximum Month End Balance Outstanding	$194.4	$121.5	$156.4	$6.3	$69.1	$76.3

Throughout the years presented, Utility Holdings has successfully placed commercial paper as needed.

New Share Issues

The Company may periodically issue new common shares to satisfy the dividend reinvestment plan, and other employee benefit plan requirements. New issuances provided additional liquidity of $6.3 million in 2016, $6.2 million in 2015, and $6.1 million in 2014.

Bonus Depreciation
On December 18, 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. The PATH Act allows for 50 percent bonus depreciation for property placed in service in 2015 - 2017; 40 percent in 2018; and 30 percent in 2019. Including the impact of alternative minimum tax credits that will be utilized in future periods, the extension of 50 percent bonus depreciation resulted in an approximate $40 million positive impact to cash flows for the 2016 tax year. Potential tax reform may impact bonus depreciation in future periods.

Potential Uses of Liquidity

Pension & Postretirement Funding Obligations
As of December 31, 2016, assets related to the Company’s qualified pension plans were approximately 92 percent of the projected benefit obligation on a GAAP basis. As of the most recent valuation report date for the Company's qualified pension plans, assets were 124 percent of the target liability for ERISA purposes. The Company currently does not anticipate making a contribution to the qualified pension plans in 2017.

Performance Guarantees & Product Warranties
In the normal course of business, wholly owned subsidiaries, such as Energy Systems Group, LLC (ESG), a subsidiary of the Energy Services operating segment, issue payment and performance bonds and other forms of assurance that commit them to timely install infrastructure, operate facilities, pay vendors and subcontractors, and support warranty obligations.

Specific to ESG's role as a general contractor in the performance contracting industry, at December 31, 2016, there are 54 open surety bonds supporting future performance. The average face amount of these obligations is $10.6 million, and the largest obligation has a face amount of $75.9 million. The maximum exposure from these obligations is limited to the level of uncompleted work and further limited by bonds issued to ESG by various contractors. At December 31, 2016, approximately 43 percent of work was yet to be completed on projects with open surety bonds. A significant portion of these open surety bonds will be released within one year. In instances where ESG operates facilities, project guarantees extend over a longer period. In addition to its performance obligations, ESG also warrants the functionality of certain installed infrastructure generally for one year and the associated energy savings over a specified number of years.

Based on a history of meeting performance obligations and installed products operating effectively, no liability or cost has been recognized for the periods presented as the Company assesses the likelihood of loss as remote. Since inception, ESG has paid a de minimis amount on energy savings guarantees.

Corporate Guarantees
The Company issues parent level guarantees to certain vendors and customers of its wholly owned subsidiaries. These guarantees do not represent incremental consolidated obligations; but rather, represent guarantees of subsidiary obligations in order to allow those subsidiaries the flexibility to conduct business without posting other forms of collateral. At December 31, 2016, parent level guarantees support a maximum of $319 million of ESG's performance contracting commitments, warranty obligations, project guarantees, and energy savings guarantees. Given the infrequent occurrence of any performance shortfalls historically on any of these commitments, no reserve for a potential liability has been deemed warranted.

Further, an energy facility operated by ESG and managed by Keenan Ft. Detrick Energy, LLC (Keenan), is governed by an operations agreement. Under this agreement, all payment obligations to Keenan are also guaranteed by the Company. The Company guarantee of the Keenan operations agreement does not state a maximum guarantee. Due to the nature of work performed under this contract, the Company cannot estimate a maximum potential amount of future payments but assesses the likelihood of loss as remote based on, primarily, the nature of the project.

In addition, the Company has other guarantees outstanding, including letters of credit, supporting other consolidated subsidiary operations.

The Company has not been called on to perform under these guarantees historically. While there can be no assurance that performance under these provisions will not be required in the future, the Company believes that the likelihood of a material amount being incurred under these provisions is remote given the nature of the projects, the manner in which the savings estimates are developed, and the fact that the value of the guarantees decrease over time as actual savings are achieved.

Planned Capital Expenditures & Investments

During 2016 capital expenditures and other investments approximated $542 million, of which approximately $500 million related to Utility Group expenditures. This compares to 2015 where consolidated capital expenditures and investments were approximately $477 million with $398 million attributed to the Utility Group and 2014 where consolidated capital expenditures and investments were approximately $448 million with $351 million attributed to the Utility Group. Planned Utility Group capital expenditures, including contractual purchase commitments, for the five-year period 2017 - 2021 are expected to total approximately (in millions): $570, $540, $555, $550, and $760, respectively. This plan contains the best estimate of the resources required for known regulatory compliance and the preferred IRP plan; however, many environmental and pipeline safety standards are subject to change in the near term. Such changes could materially impact planned capital expenditures.

Planned Nonutility Group capital expenditures, including contractual purchase commitments, for the five-year period 2017 - 2021 are expected to total (in millions): $50, $40, $50, $60, and $60, respectively.

Contractual Obligations

The following is a summary of contractual obligations at December 31, 2016:

(In millions)	Total	2017	2018	2019	2020	2021	Thereafter
Long-term debt [1]	$1,714.0	$124.1	$100.0	$60.0	$100.0	$55.0	$ 1,274.9
Short-term debt	194.4	194.4	—	—	—	—	—
Long-term debt interest commitments	1,105.8	80.4	75.5	68.6	63.1	61.2	757.0
Plant and nonutility plant purchase commitments	8.3	6.8	1.5	—	—	—	—
Operating leases	29.3	9.8	7.3	4.4	2.1	1.8	3.9
Total [2]	$3,051.8	$415.5	$184.3	$133.0	$165.2	$118.0	$ 2,035.8

(1) The debt due in 2017 is comprised of debt issued by Vectren Capital.

(2) The Company has other long-term liabilities that total approximately $249 million. This amount is comprised of the following: pension obligations $45 million; postretirement obligations $36 million; deferred compensation and share-based compensation obligations $54 million; asset retirement obligations $107 million; investment tax credits $2 million; environmental remediation obligations $3 million; and other obligations including unrecognized tax benefits totaling $4 million. Based on the nature of these items, their expected settlement dates cannot be estimated.

The Company's regulated utilities have both firm and non-firm commitments, some of which are between five and twenty year agreements, to purchase natural gas, coal, and electricity, as well as certain transportation and storage rights. Costs arising from these commitments, while significant, are pass-through costs, generally collected dollar-for-dollar from retail customers through regulator-approved cost recovery mechanisms. Because of the pass through nature of these costs, they have not been included in the listing of contractual obligations.

Comparison of Historical Sources & Uses of Liquidity

Operating Cash Flow

The Company's primary source of liquidity to fund capital requirements has been cash generated from operations, which totaled $524.1 million in 2016, compared to $505.2 million in 2015 and $488.2 million in 2014.

The $18.9 million increase in operating cash flow in 2016 compared to 2015 is driven primarily by increased earnings and by changes in certain working capital accounts that reflect weather impacts, specifically the decreases in accounts receivable recoverable/refundable fuel and natural gas costs.

In 2015, operating cash flows increased $17 million compared to 2014. Weather related impacts include the fluctuation in recoverable/refundable fuel and natural gas costs and prepaid gas costs. The decrease in tax payments in 2015 reflects the full impact of bonus depreciation, and in 2014, bonus depreciation impacts were reduced due to tax payments related to the sale of Vectren Fuels. Additionally, in 2015, there was a decrease in prepaid taxes due to the timing of a federal refund received related to the extension of bonus depreciation in late 2014. These increases are offset somewhat by an increase in contributions to qualified pension plans in 2015 and growth in in regulatory assets related to increased spend on infrastructure programs.

Tax payments in the periods presented were favorably impacted by federal legislation extending bonus depreciation. Federal legislation allowing bonus depreciation on qualifying capital expenditures was 50 percent for each of the years 2016, 2015, and 2014. A significant portion of the Company’s capital expenditures qualified for this bonus treatment.

Financing Cash Flow

Net cash flow required for financing activities was $21.0 million, $47.3 million, and $257.6 million for the years ended December 31, 2016, 2015, and 2014, respectively. Financing activity in 2015 and 2014 reflects the Company’s utilization of the long-term capital markets in the current low interest rate environment. These lower rates have favorably impacted interest expense throughout the periods presented. In the current year, the Company had an increase of short term borrowings which was partially offset by the retirement of $73 million in long-term debt. In 2015, the Company issued $388 million in long-term debt, which was partially offset by the retirement of $170 million in long-term debt, and an increased amount of short-term borrowings paid. In 2014, the Company retired approximately $124 million more in long-term debt compared to 2015 due principally to the use of proceeds from the sale of Vectren Fuels. The Company’s operating cash flow funded over 77 percent of capital expenditures and dividends in 2016, over 83 percent in 2015, and 85 percent in 2014. Certain recently completed financing transactions are more fully described below.

Vectren Capital Unsecured Note Retirement
On March 11, 2016, a $60 million Vectren Capital senior unsecured note matured. The Series B note, which was part of a private placement Note Purchase Agreement entered into on March 11, 2009, carried a fixed interest rate of 6.92 percent. The repayment of debt was funded from the Company's cash on hand.

SIGECO Bond Retirement
On June 1, 2016, a $13 million SIGECO bond matured. The First Mortgage Bond, which was a portion of an original $25 million public issuance sold on June 1, 1986 carried a fixed interest rate of 8.875 percent. The repayment of debt was funded from the Company’s commercial paper program.

Indiana Gas Unsecured Note Retirement
On March 15, 2015, a $5 million Indiana Gas senior unsecured note matured. The Series E note carried a fixed interest rate of 7.15 percent. The repayment of debt was funded by the Company's commercial paper program.

SIGECO Debt Issuance
On September 9, 2015, SIGECO completed a $38.2 million tax-exempt first mortgage bond issuance. The principal terms of the two new series of tax-exempt debt are: (i) $23.0 million in Environmental Improvement Revenue Bonds, Series 2015, issued by the City of Mount Vernon, Indiana and (ii) $15.2 million in Environmental Improvement Revenue Bonds, Series 2015, issued by Warrick County, Indiana. Both bonds were sold in a public offering at an initial interest rate of 2.375 percent per annum that is fixed until September 1, 2020 when the bonds will be remarketed. The bonds have a final maturity of September 1, 2055.

Vectren Utility Holdings, Vectren Capital, and Indiana Gas Debt Transactions
On December 15, 2015, Utility Holdings issued Guaranteed Senior Notes in a private placement to various institutional investors in the following tranches: (i) $25 million of 3.90 percent Guaranteed Senior Notes, Series A, due December 15, 2035, (ii) $135 million of 4.36 percent Guaranteed Senior Notes, Series B, due December 15, 2045, and (iii) $40 million of 4.51 percent Guaranteed Senior Notes, Series C, due December 15, 2055. The notes are unconditionally guaranteed by Indiana Gas, SIGECO and VEDO.

Additionally, on December 15, 2015, Vectren Capital issued Guaranteed Senior Notes in a private placement to various institutional investors in the following tranches: (i) $75 million of 3.33 percent Guaranteed Senior Notes, Series A, due December 15, 2022 and (ii) $75 million of 3.90 percent Guaranteed Senior Notes, Series B, due December 15, 2030. The notes are guaranteed by Vectren Corporation.

A portion of the proceeds received from these issuances were used to finance the following retirements of debt: (i) $75 million of 5.45% Utility Holdings senior unsecured notes that matured on December 1, 2015, (ii) $75 million of 5.31% Vectren Capital senior unsecured notes that matured on December 15, 2015, and (iii) $5 and $10 million of 6.69% Indiana Gas senior unsecured notes that matured on December 21, and 29, 2015, respectively.

Vectren Capital Unsecured Note Retirement
On March 11, 2014, a $30 million Vectren Capital senior unsecured note matured. The Series A note, which was part of a private placement Note Purchase Agreement entered into on March 11, 2009, carried a fixed interest rate of 6.37 percent. The repayment of debt was funded from the Company's short-term credit facility.

SIGECO Debt Refund and Issuance
On September 24, 2014, SIGECO issued two new series of tax-exempt debt totaling $63.6 million. Proceeds from the issuance were used to retire three series of tax-exempt bonds aggregating $63.6 million at a redemption price of par plus accrued interest. The principal terms of the two new series of tax-exempt debt are: (i) $22.3 million sold in a public offering and bear interest at 4.00 percent per annum, due September 1, 2044 and (ii) $41.3 million, due July 1, 2025, sold in a private placement at variable rates through September 2019.

Sale of Vectren Fuels Proceeds
On August 29, 2014, the Company closed on a transaction to sell its wholly owned coal mining subsidiary, Vectren Fuels, to Sunrise Coal. The proceeds received, net of transaction costs and estimated tax payments, totaled $285 million and were used to retire $200 million in outstanding Vectren Capital bank term loans and pay down outstanding short-term debt.

Mandatory Tenders
At December 31, 2016, certain series of SIGECO bonds, aggregating $87.3 million, currently bear interest at fixed rates, of which $49.1 million is subject to mandatory tender in September 2017 and $38.2 million is subject to mandatory tender in September 2020. Additionally, SIGECO Bond Series 2014B, in the amount of $41.3 million, with a variable interest rate that is reset monthly, is subject to mandatory tender in September 2019.

Investing Cash Flow

Cash flow required for investing activities was $509.2 million in 2016, $469.6 million in 2015, and $165.7 million in 2014. The primary use of cash in all periods presented reflect utility and nonutility capital expenditures. Capital expenditures increased in 2016 as compared to 2015 by $65.1 million, and also increased in 2015 as compared to 2014 by $28.6 million. The increase in capital expenditures is attributable to greater expenditures for gas infrastructure improvement projects and environmental compliance. Cash flow required for investing activities in 2014 reflects the receipt of $311 million in proceeds from the sale of Vectren Fuels and reflects the acquisition of the federal business unit from Chevron Energy Solutions.

Forward-Looking Information

A “safe harbor” for forward-looking statements is provided by the Private Securities Litigation Reform Act of 1995 (Reform Act of 1995). The Reform Act of 1995 was adopted to encourage such forward-looking statements without the threat of litigation, provided those statements are identified as forward-looking and are accompanied by meaningful cautionary statements identifying important factors that could cause the actual results to differ materially from those projected in the statement. Certain matters described in Management’s Discussion and Analysis of Results of Operations and Financial Condition are forward-looking statements. Such statements are based on management’s beliefs, as well as assumptions made by and information currently available to management. When used in this filing, the words “believe”, “anticipate”, “endeavor”, “estimate”, “expect”, “objective”, “projection”, “forecast”, “goal”, “likely”, and expressions are intended to identify forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements, factors that could cause the Company’s actual results to differ materially from those contemplated in any forward-looking statements include, among others, the following:

- Factors affecting utility operations such as unfavorable or unusual weather conditions; catastrophic weather-related damage; unusual maintenance or repairs; unanticipated changes to coal and natural gas costs; unanticipated changes to gas transportation and storage costs, or availability due to higher demand, shortages, transportation problems or other developments; environmental or pipeline incidents; transmission or distribution incidents; unanticipated changes to electric energy supply costs, or availability due to demand, shortages, transmission problems or other developments; or electric transmission or gas pipeline system constraints.
- New legislation, litigation and government regulation or other actions, such as changes in or additions to tax laws or rates, pipeline safety regulation and environmental laws, including laws governing air emissions, including carbon, waste water discharges and the handling and disposal of coal combustion residuals that could impact the continued operation, and/or cost recovery of generation plants and related assets. These compliance costs could substantially change the nature of the Company's generation fleet.
- Catastrophic events such as fires, earthquakes, explosions, floods, ice storms, tornadoes, terrorist acts, physical attacks, cyber attacks, or other similar occurrences could adversely affect the Company's facilities, operations, financial condition, results of operations, and reputation.
- Increased competition in the energy industry, including the effects of industry restructuring, unbundling, and other sources of energy.
- Regulatory factors such as uncertainty surrounding the composition of state regulatory commissions, adverse regulatory changes, unanticipated changes in rate-setting policies or procedures, recovery of investments and costs made under regulation, interpretation of regulatory-related legislation by the IURC and/or PUCO and appellate courts that review decisions issued by the agencies, and the frequency and timing of rate increases.
- Financial, regulatory or accounting principles or policies imposed by the Financial Accounting Standards Board; the Securities and Exchange Commission; the Federal Energy Regulatory Commission; state public utility commissions; state entities which regulate electric and natural gas transmission and distribution, natural gas gathering and processing, electric power supply; and similar entities with regulatory oversight.
- Economic conditions including the effects of inflation, commodity prices, and monetary fluctuations.
- Economic conditions surrounding the current economic uncertainty, including increased potential for lower levels of economic activity; uncertainty regarding energy prices and the capital and commodity markets; volatile changes in the demand for natural gas, electricity, and other nonutility products and services; economic impacts of changes in business strategy on both gas and electric large customers; lower residential and commercial customer counts; variance from normal population growth and changes in customer mix; higher operating expenses; and reductions in the value of investments.
- Volatile natural gas and coal commodity prices and the potential impact on customer consumption, uncollectible accounts expense, unaccounted for gas and interest expense.
- Volatile oil prices and the potential impact on customer consumption and price of other fuel commodities.

- Direct or indirect effects on the Company's business, financial condition, liquidity and results of operations resulting from changes in credit ratings, changes in interest rates, and/or changes in market perceptions of the utility industry and other energy-related industries.

- The performance of projects undertaken by the Company’s nonutility businesses and the success of efforts to realize value from, invest in and develop new opportunities, including but not limited to, the Company’s Infrastructure Services, Energy Services, and remaining ProLiance Holdings assets.
- Factors affecting Infrastructure Services, including the level of success in bidding contracts; fluctuations in volume and mix of contracted work; mix of projects received under blanket contracts; unanticipated cost increases in completion of the contracted work; funding requirements associated with multiemployer pension and benefit plans; changes in legislation and regulations impacting the industries in which the customers served operate; the effects of weather; failure to properly estimate the cost to construct projects; the ability to attract and retain qualified employees in a fast growing market where skills are critical; cancellation and/or reductions in the scope of projects by customers; credit worthiness of customers; ability to obtain materials and equipment required to perform services; and changing market conditions, including changes in the market prices of oil and natural gas that would affect the demand for infrastructure construction.
- Factors affecting Energy Services, including unanticipated cost increases in completion of the contracted work; changes in legislation and regulations impacting the industries in which the customers served operate; changes in economic influences impacting customers served; failure to properly estimate the cost to construct projects; risks associated with projects owned or operated; failure to appropriately design, construct, or operate projects; the ability to attract and retain qualified employees; cancellation and/or reductions in the scope of projects by customers; changes in the timing of being awarded projects; credit worthiness of customers; lower energy prices negatively impacting the economics of performance contracting business; and changing market conditions.
- Employee or contractor workforce factors including changes in key executives, collective bargaining agreements with union employees, aging workforce issues, work stoppages, or pandemic illness.
- Risks associated with material business transactions such as acquisitions and divestitures, including, without limitation, legal and regulatory delays; the related time and costs of implementing such transactions; integrating operations as part of these transactions; and possible failures to achieve expected gains, revenue growth and/or expense savings from such transactions.
- Costs, fines, penalties and other effects of legal and administrative proceedings, settlements, investigations, claims, including, but not limited to, such matters involving compliance with federal and state laws and interpretations of these laws.

The Company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of changes in actual results, changes in assumptions, or other factors affecting such statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to various business risks associated with commodity prices, interest rates, and counter-party credit. These financial exposures are monitored and managed by the Company as an integral part of its overall risk management program. The Company’s risk management program includes, among other things, the occasional use of derivatives. The Company will, from time to time, execute derivative contracts in the normal course of operations while buying and selling commodities and when managing interest rate risk.

The Company has a risk management committee that consists of senior management as well as financial and operational management. The committee is actively involved in identifying risks as well as reviewing and authorizing risk mitigation strategies.

Commodity Price Risk

Regulated Operations

The Company’s regulated operations have limited exposure to commodity price risk for transactions involving purchases and sales of natural gas, coal and purchased power for the benefit of retail customers due to current state regulations, which subject to compliance with those regulations, allow for recovery of the cost of such purchases through natural gas and fuel cost adjustment mechanisms. Constructive regulatory orders, such as those authorizing lost margin recovery, other innovative rate designs, and recovery of unaccounted for gas and other gas related expenses, also mitigate the effect gas costs may have on the Company's financial condition. Although the Company's regulated operations are exposed to limited commodity price risk, natural gas and coal prices have other effects on working capital requirements, interest costs, and some level of price-sensitivity in volumes sold or delivered. Indiana Gas and SIGECO hedge up to 50 percent of annual natural gas purchases for each Company utilizing a variety of terms for physical fixed-price purchases up to 10 years in duration. Indiana Gas also utilizes financial products, including call options. Such option contracts are generally short-term in nature and are insignificant in terms of value and volume at December 31, 2016 and 2015. However, it is possible that the utilization of these instruments may grow in the future.

Wholesale Power Marketing

The Company's wholesale power marketing activities undertake strategies to optimize electric generating capacity beyond that needed for native load. In recent years, the primary strategy involves the sale of generation into the MISO Day Ahead and Real-time markets. The Company accounts for any energy contracts that are derivatives at fair value with the offset marked to market through earnings. No derivative positions were outstanding on December 31, 2016 and 2015.

For retail sales of electricity, the Company receives the majority of its NOx and SO_2 allowances at zero cost through an allocation process. Based on arrangements with regulators, wholesale operations can purchase allowances from retail operations at current market values, the value of which is distributed back to retail customers through a MISO cost recovery tracking mechanism. Wholesale operations are therefore at risk for the cost of allowances, which for the recent past have been volatile. The Company manages this risk by purchasing allowances from retail operations as needed and occasionally from other third parties in advance of usage.

Other Operations

Other commodity-related operations are exposed to commodity price risk associated with gasoline/diesel through third party suppliers. Occasionally, the Company will hedge a portion of such requirements using financial instruments and using physically settled forward purchase contracts. However, during the years presented, such utilization has not been significant.

Interest Rate Risk

The Company is exposed to interest rate risk associated with its borrowing arrangements. Its risk management program seeks to reduce the potentially adverse effects that market volatility may have on interest expense. As of December 31, 2016, debt subject to interest rate volatility was approximately 12 percent. To further manage this exposure, the Company may also use derivative financial instruments.

Market risk is estimated as the potential impact resulting from fluctuations in interest rates on adjustable rate borrowing arrangements exposed to short-term interest rate volatility. During 2016 and 2015, the weighted average combined borrowings under these arrangements approximated $101 million and $120 million, respectively. At December 31, 2016, combined borrowings under these arrangements were $236 million. As of December 31, 2015 combined borrowings under these arrangements were $56 million. Based upon average borrowing rates under these facilities during the years ended December 31, 2016 and 2015, an increase of 100 basis points (one percentage point) in the rates would have increased interest expense by approximately $1.0 million in 2016 and $1.2 million in 2015.

Other Risks

By using financial instruments and physically settled fixed price forward contracts to manage risk, the Company creates exposure to counter-party credit risk and market risk. The Company manages exposure to counter-party credit risk by entering into contracts with companies that can be reasonably expected to fully perform under the terms of the contract. Counter-party credit risk is monitored regularly and positions are adjusted appropriately to manage risk. Further, tools such as netting arrangements and requests for collateral are also used to manage credit risk. Market risk is the adverse effect on the value of a financial instrument that results from a change in commodity prices or interest rates. The Company attempts to manage exposure to market risk associated with commodity contracts and interest rates by establishing parameters and monitoring those parameters that limit the types and degree of market risk that may be undertaken.

The Company’s customer receivables associated with utility operations are primarily derived from residential, commercial, and industrial customers located in Indiana and west central Ohio. However, some exposure from nonutility operations extends throughout the United States. The Company manages credit risk associated with its receivables by continually reviewing creditworthiness and requests cash deposits or refunds cash deposits based on that review. Credit risk associated with certain investments is also managed by a review of creditworthiness and receipt of collateral. In addition, credit risk for the Company's utilities is mitigated by regulatory orders that allow recovery of all uncollectible accounts expense in Ohio and the gas cost portion of uncollectible accounts expense in Indiana based on historical experience.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MANAGEMENT’S RESPONSIBILITY FOR THE FINANCIAL STATEMENTS

Vectren Corporation’s management is responsible for establishing and maintaining adequate internal control over financial reporting. Those control procedures underlie the preparation of the consolidated balance sheets, statements of income, comprehensive income, cash flows, and common shareholders’ equity, and related footnotes contained herein.

These consolidated financial statements were prepared in conformity with accounting principles generally accepted in the United States and follow accounting policies and principles applicable to regulated public utilities. The integrity and objectivity of these consolidated financial statements, including required estimates and judgments, is the responsibility of management.

These consolidated financial statements are also subject to an evaluation of internal control over financial reporting conducted under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer. Based on that evaluation, conducted under the framework in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, the Company concluded that its internal control over financial reporting was effective as of December 31, 2016. Management certified this in its Sarbanes Oxley Section 302 certifications, which are filed as exhibits to this 2016 Form 10-K.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Vectren Corporation:

We have audited the accompanying consolidated balance sheets of Vectren Corporation and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2016. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Vectren Corporation and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2016, based on the criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 23, 2017 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP
Indianapolis, Indiana
February 23, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Vectren Corporation:

We have audited the internal control over financial reporting of Vectren Corporation and subsidiaries (the "Company") as of December 31, 2016, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. 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 conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether 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.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2016 of the Company and our report dated February 23, 2017 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ DELOITTE & TOUCHE LLP
Indianapolis, Indiana
February 23, 2017

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(In millions)

	At December 31,	
	2016	2015
ASSETS		
Current Assets		
Cash & cash equivalents	$68.6	$74.7
Accounts receivable - less reserves of $6.0 & $5.6, respectively	225.3	227.5
Accrued unbilled revenues	172.4	142.5
Inventories	129.9	133.7
Recoverable fuel & natural gas costs	29.9	—
Prepayments & other current assets	52.7	81.0
Total current assets	678.8	659.4
Utility Plant		
Original cost	6,545.4	6,090.4
Less: accumulated depreciation & amortization	2,562.5	2,415.5
Net utility plant	3,982.9	3,674.9
Investments in unconsolidated affiliates	20.4	20.9
Other utility & corporate investments	34.1	31.2
Other nonutility investments	16.1	16.2
Nonutility plant - net	423.9	414.6
Goodwill	293.5	293.5
Regulatory assets	308.8	249.4
Other assets	42.2	39.9
TOTAL ASSETS	$5,800.7	$5,400.0

The accompanying notes are an integral part of these consolidated financial statements.

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(In millions)

	At December 31,	
	2016	2015
LIABILITIES & SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$302.2	$248.8
Refundable fuel & natural gas costs	—	7.9
Accrued liabilities	207.7	183.6
Short-term borrowings	194.4	14.5
Current maturities of long-term debt	124.1	73.0
Total current liabilities	828.4	527.8
Long-term Debt - Net of Current Maturities	1,589.9	1,712.9
Deferred Credits & Other Liabilities		
Deferred income taxes	905.7	805.4
Regulatory liabilities	453.7	433.9
Deferred credits & other liabilities	254.9	236.2
Total deferred credits & other liabilities	1,614.3	1,475.5
Commitments & Contingencies (Notes 7, 17-20)		
Common Shareholders' Equity		
Common stock (no par value) - issued & outstanding 82.9 & 82.8 shares, respectively	729.8	722.8
Retained earnings	1,039.6	962.2
Accumulated other comprehensive (loss)	(1.3)	(1.2)
Total common shareholders' equity	1,768.1	1,683.8
TOTAL LIABILITIES & SHAREHOLDERS' EQUITY	$5,800.7	$5,400.0

The accompanying notes are an integral part of these consolidated financial statements.

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
(In millions, except per share amounts)

	Year Ended December 31,		
	2016	2015	2014
OPERATING REVENUES			
Gas utility	$771.7	$792.6	$944.6
Electric utility	605.8	601.6	624.8
Nonutility	1,070.8	1,040.5	1,042.3
Total operating revenues	2,448.3	2,434.7	2,611.7
OPERATING EXPENSES			
Cost of gas sold	266.7	305.4	468.7
Cost of fuel & purchased power	183.6	187.5	201.8
Cost of nonutility revenues	363.4	355.0	346.4
Other operating	932.2	909.2	943.4
Depreciation & amortization	260.0	256.3	273.4
Taxes other than income taxes	60.9	59.5	63.5
Total operating expenses	2,066.8	2,072.9	2,297.2
OPERATING INCOME	381.5	361.8	314.5
OTHER INCOME			
Equity in earnings (losses) of unconsolidated affiliates	(0.2)	(0.6)	0.5
Other income – net	28.7	20.3	19.7
Total other income	28.5	19.7	20.2
Interest expense	85.5	84.5	86.7
INCOME BEFORE INCOME TAXES	324.5	297.0	248.0
Income taxes	112.9	99.7	81.1
NET INCOME	$211.6	$197.3	$166.9
WEIGHTED AVERAGE AND DILUTED COMMON SHARES OUTSTANDING	82.8	82.7	82.5
BASIC AND DILUTED EARNINGS PER SHARE OF COMMON STOCK	$2.55	$2.39	$2.02

The accompanying notes are an integral part of these consolidated financial statements.

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Year Ended December 31,		
	2016	2015	2014
NET INCOME	$211.6	$197.3	$166.9
Pension & other benefits			
Amounts arising during the year before tax	(10.1)	1.2	(52.6)
Reclassifications to periodic cost before tax	4.7	6.9	3.4
Deferrals to regulatory assets	5.3	(8.0)	48.2
Income taxes	—	—	0.4
Pension & other benefits costs, net of tax	(0.1)	0.1	(0.6)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX	(0.1)	0.1	(0.6)
TOTAL COMPREHENSIVE INCOME	$211.5	$197.4	$166.3

The accompanying notes are an integral part of these consolidated financial statements.

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2016	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$211.6	$197.3	$166.9
Adjustments to reconcile net income to cash from operating activities:			
Depreciation & amortization	260.0	256.3	273.4
Deferred income taxes & investment tax credits	100.1	80.4	37.9
Provision for uncollectible accounts	6.9	8.1	7.3
Expense portion of pension & postretirement benefit cost	3.6	6.8	6.6
Other non-cash charges - net	7.8	7.3	5.3
Loss on sale of business (pretax)	—	—	41.8
Gain on revaluation of contingent consideration	—	—	(14.8)
Changes in working capital accounts:			
Accounts receivable & accrued unbilled revenues	(39.6)	(15.4)	11.8
Inventories	3.9	(15.2)	(22.5)
Recoverable/refundable fuel & natural gas costs	(37.8)	15.2	(4.4)
Prepayments & other current assets	22.9	20.3	(35.2)
Accounts payable, including to affiliated companies	40.7	(0.5)	20.2
Accrued liabilities	22.7	(0.9)	12.3
Employer contributions to pension & postretirement plans	(19.6)	(26.5)	(5.1)
Changes in noncurrent assets	(44.0)	(21.9)	0.1
Changes in noncurrent liabilities	(15.1)	(6.1)	(13.4)
Net cash provided by operating activities	524.1	505.2	488.2
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from:			
Long-term debt, net of issuance costs	—	385.5	62.4
Dividend reinvestment plan & other common stock issuances	6.3	6.2	6.1
Requirements for:			
Dividends on common stock	(134.2)	(127.3)	(120.4)
Retirement of long-term debt	(73.0)	(170.0)	(293.6)
Other financing activities	—	0.2	0.1
Net change in short-term borrowings	179.9	(141.9)	87.8
Net cash used in financing activities	(21.0)	(47.3)	(257.6)
CASH FLOWS FROM INVESTING ACTIVITIES			
Proceeds from:			
Sale of business	—	—	311.2
Sale of assets and other collections	33.0	27.5	9.5
Requirements for:			
Capital expenditures, excluding AFUDC equity	(542.0)	(476.9)	(448.3)
Business acquisitions and other costs	(5.2)	(14.3)	(38.1)
Changes in restricted cash	5.0	(5.9)	—
Net cash used in investing activities	(509.2)	(469.6)	(165.7)
Net change in cash & cash equivalents	(6.1)	(11.7)	64.9
Cash & cash equivalents at beginning of period	74.7	86.4	21.5
Cash & cash equivalents at end of period	$68.6	$74.7	$86.4

The accompanying notes are an integral part of these consolidated financial statements.

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY
(In millions, except per share amounts)

	Common Stock			Accumulated Other	
	Shares	Amount	Retained Earnings	Comprehensive Income (Loss)	Total
Balance at January 1, 2014	82.4	$ 709.3	$ 845.7	$ (0.7)	$ 1,554.3
Net income			166.9		166.9
Other comprehensive income (loss)				(0.6)	(0.6)
Common stock:					
Issuance: option exercises & dividend reinvestment plan	0.2	6.1			6.1
Dividends ($1.460 per share)			(120.4)		(120.4)
Other		0.3			0.3
Balance at December 31, 2014	82.6	715.7	892.2	(1.3)	1,606.6
Net income			197.3		197.3
Other comprehensive income				0.1	0.1
Common stock:					
Issuance: option exercises & dividend reinvestment plan	0.2	6.2			6.2
Dividends ($1.540 per share)			(127.3)		(127.3)
Other		0.9			0.9
Balance at December 31, 2015	82.8	722.8	962.2	(1.2)	1,683.8
Net income			211.6		211.6
Other comprehensive income (loss)				(0.1)	(0.1)
Common stock:					
Issuance: dividend reinvestment plan	0.1	6.3			6.3
Dividends ($1.620 per share)			(134.2)		(134.2)
Other		0.7			0.7
Balance at December 31, 2016	82.9	$ 729.8	$ 1,039.6	$ (1.3)	$ 1,768.1

The accompanying notes are an integral part of these consolidated financial statements.

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Nature of Operations

Vectren Corporation (the Company or Vectren), an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana. The Company's wholly owned subsidiary, Vectren Utility Holdings, Inc. (Utility Holdings or VUHI), serves as the intermediate holding company for three public utilities: Indiana Gas Company, Inc. (Indiana Gas or Vectren Energy Delivery of Indiana - North), Southern Indiana Gas and Electric Company (SIGECO or Vectren Energy Delivery of Indiana - South), and Vectren Energy Delivery of Ohio, Inc. (VEDO). Utility Holdings also has other assets that provide information technology and other services to the three utilities. Utility Holdings' consolidated operations are collectively referred to as the Utility Group. Both Vectren and Utility Holdings are holding companies as defined by the Energy Policy Act of 2005. Vectren was incorporated under the laws of Indiana on June 10, 1999.

Indiana Gas provides energy delivery services to approximately 587,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 144,000 electric customers and approximately 111,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to approximately 316,000 natural gas customers located near Dayton in west central Ohio.

The Company, through Vectren Enterprises, Inc. (Enterprises), is involved in nonutility activities in two primary business areas: Infrastructure Services and Energy Services. Infrastructure Services provides underground pipeline construction and repair services. Energy Services provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects. Prior to August 29, 2014, the Company had activities in a coal mining business. Results in the financial statements include the results of Vectren Fuels, Inc. (Vectren Fuels) through the date of sale of August 29, 2014, when the Company exited the coal mining business. Enterprises also has other legacy businesses that have investments in energy-related opportunities and services and other investments. All of the above is collectively referred to as the Nonutility Group. Enterprises supports the Company's regulated utilities by providing infrastructure services.

2. Summary of Significant Accounting Policies

In applying its accounting policies, the Company makes judgments, assumptions, and estimates that affect the amounts reported in these consolidated financial statements and related footnotes. Examples of transactions for which estimation techniques are used include valuing pension and postretirement benefit obligations, deferred tax obligations, unbilled revenue, uncollectible accounts, regulatory assets and liabilities, asset retirement obligations, and derivatives and other financial instruments. Estimates also impact the depreciation of utility and nonutility plant and the testing of goodwill and other assets for impairment. Recorded estimates are revised when better information becomes available or when actual amounts can be determined. Actual results could differ from current estimates.

Principles of Consolidation
The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries, after appropriate elimination of intercompany transactions. The Infrastructure Services segment, through wholly owned subsidiaries Miller Pipeline, LLC and Minnesota Limited, LLC, provides underground pipeline construction and repair services for customers that include Vectren Utility Holdings' utilities. In accordance with consolidation

guidance under ASC 980, fees incurred by Vectren Utility Holdings and its subsidiaries for these pipeline construction and repair services, are appropriately not eliminated in consolidation.

Subsequent Events Review
Management performs a review of subsequent events for any events occurring after the balance sheet date but prior to the date the financial statements are issued.

Cash & Cash Equivalents
Highly liquid investments with an original maturity of three months or less at the date of purchase are considered cash equivalents. Cash and cash equivalents are stated at cost plus accrued interest to approximate fair value.

Allowance for Uncollectible Accounts
The Company maintains allowances for uncollectible accounts for estimated losses resulting from the inability of its customers to make required payments. The Company estimates the allowance for uncollectible accounts based on a variety of factors including the length of time receivables are past due, the financial health of its customers, unusual macroeconomic conditions, and historical experience. If the financial condition of its customers deteriorates or other circumstances occur that result in an impairment of customers' ability to make payments, the Company records additional allowances as needed.

Inventories
In most circumstances, the Company's inventory components are recorded using an average cost method; however, natural gas in storage at the Company's Indiana utilities are recorded using the Last In – First Out (LIFO) method. Inventory related to the Company's regulated operations is valued at historical cost consistent with ratemaking treatment. Materials and supplies are recorded as inventory when purchased and subsequently charged to expense or capitalized to plant when installed.

Property, Plant & Equipment
Both the Company's Utility Plant and Nonutility Plant is stated at historical cost, inclusive of financing costs and direct and indirect construction costs, less accumulated depreciation and when necessary, impairment charges. The cost of renewals and betterments that extend the useful life are capitalized. Maintenance and repairs, including the cost of removal of minor items of property and planned major maintenance projects, are charged to expense as incurred.

Utility Plant & Related Depreciation
Both the IURC and PUCO allow the Company's utilities to capitalize financing costs associated with Utility Plant based on a computed interest cost and a designated cost of equity funds. These financing costs are commonly referred to as AFUDC and are capitalized for ratemaking purposes and for financial reporting purposes instead of amounts that would otherwise be capitalized when acquiring nonutility plant. The Company reports both the debt and equity components of AFUDC in Other – net in the Consolidated Statements of Income.

When property that represents a retirement unit is replaced or removed, the remaining historical value of such property is charged to Utility Plant, with an offsetting charge to Accumulated depreciation, resulting in no gain or loss. Costs to dismantle and remove retired property are recovered through the depreciation rates as determined by the IURC and PUCO.

The Company's portion of jointly owned Utility Plant, along with that plant's related operating expenses, is presented in these financial statements in proportion to the ownership percentage.

Nonutility Plant & Related Depreciation
The depreciation of Nonutility Plant is charged against income over its estimated useful life, using the straight-line method of depreciation. When nonutility property is retired, or otherwise disposed of, the asset and accumulated depreciation are removed, and the resulting gain or loss is reflected in income, typically impacting operating expenses.

Impairment Reviews

Property, plant and equipment along with other long-lived assets are reviewed as facts and circumstances indicate that the carrying amount may be impaired. This impairment review involves the comparison of an asset's (or group of assets') carrying value to the estimated future cash flows the asset (or asset group) is expected to generate over a remaining life. If this evaluation were to conclude that the carrying value is impaired, an impairment charge would be recorded based on the difference between the carrying amount and its fair value (less costs to sell for assets to be disposed of by sale) as a charge to operations or discontinued operations.

Investments in Unconsolidated Affiliates
Investments in unconsolidated affiliates where the Company has significant influence are accounted for using the equity method of accounting. The Company's share of net income or loss from these investments is recorded in Equity in earnings (losses) of unconsolidated affiliates. Dividends are recorded as a reduction of the carrying value of the investment when received. Investments in unconsolidated affiliates where the Company does not have significant influence are accounted for using the cost method of accounting. Dividends associated with cost method investments are recorded as Other income – net when received. Investments are reviewed as facts and circumstances indicate that the carrying amount may be impaired. This impairment review involves the comparison of an investment's fair value to its carrying value. Investments, when necessary, include adjustments for declines in value judged to be other than temporary.

Goodwill
Goodwill recorded on the Consolidated Balance Sheets results from business acquisitions and is based on a fair value allocation of the businesses' purchase price at the time of acquisition. Goodwill is charged to expense only when it is impaired. The Company tests its goodwill for impairment at an operating segment level because the components within the segments are similar. These tests are performed at least annually and at the beginning of each year. Impairment reviews consist of a comparison of fair value to the carrying amount. If the fair value is less than the carrying amount, an impairment loss is recognized in operations. No goodwill impairments have been recorded during the periods presented.

Regulation
Retail public utility operations affecting Indiana customers are subject to regulation by the IURC, and retail public utility operations affecting Ohio customers are subject to regulation by the PUCO. The Company's accounting policies give recognition to the ratemaking and accounting practices authorized by these agencies.

Refundable or Recoverable Gas Costs & Cost of Fuel & Purchased Power
All metered gas rates in Indiana contain a gas cost adjustment clause that allows the Company to charge for changes in the cost of purchased gas. Metered electric rates contain a fuel adjustment clause that allows for adjustment in charges for electric energy to reflect changes in the cost of fuel. The net energy cost of purchased power, subject to a variable benchmark based on NYMEX natural gas prices, is also recovered through regulatory proceedings. The Company records any under-or-over-recovery resulting from gas and fuel adjustment clauses each month in revenues. A corresponding asset or liability is recorded until the under-or-over-recovery is billed or refunded to utility customers. The cost of gas sold is charged to operating expense as delivered to customers, and the cost of fuel and purchased power for electric generation is charged to operating expense when consumed.

Regulatory Assets & Liabilities
Regulatory assets represent certain incurred costs, which will result in probable future cash recoveries from customers through the ratemaking process. Regulatory liabilities represent probable expenditures by the Company for removal costs or future reductions in revenues associated with amounts that are to be credited to customers through the ratemaking process. The Company continually assesses the recoverability of costs recognized as regulatory assets and liabilities and the ability to recognize new regulatory assets and liabilities associated with its regulated utility operations. Given the current regulatory environment in its jurisdictions, the Company believes such accounting is appropriate.

The Company collects an estimated cost of removal of its utility plant through depreciation rates established in regulatory proceedings. The Company records amounts expensed in advance of payments as a Regulatory liability because the liability does not meet the threshold of an asset retirement obligation.

Postretirement Obligations & Costs

The Company recognizes the funded status of its pension plans and postretirement plans on its balance sheet. The funded status of a defined benefit plan is its assets (if any) less its projected benefit obligation (PBO), which reflects service accrued to date and includes the impact of projected salary increases (for pay-related benefits). The funded status of a postretirement plan is its assets (if any) less its accumulated postretirement benefit obligation (APBO), which reflects accrued service to date. To the extent this obligation exceeds amounts previously recognized in the statement of income, the Company records a

Regulatory asset for that portion related to its rate regulated utilities. To the extent that excess liability does not relate to a rate regulated utility, the offset is recorded as a reduction to equity in Accumulated other comprehensive income.

The annual cost of all postretirement plans is recognized in operating expenses or capitalized to plant following the direct labor of current employees. Specific to pension plans, the Company uses the projected unit credit actuarial cost method to calculate service cost and the PBO. This method projects the present value of benefits at retirement and allocates that cost over the projected years of service. Annual service cost represents one year's benefit accrual while the PBO represents benefits allocated to previously accrued service. For other postretirement plans, service cost is calculated by dividing the present value of a participant's projected postretirement benefits into equal parts based upon the number of years between a participant's hire date and first eligible retirement date. Annual service cost represents one year's benefit accrual while the APBO represents benefit allocated to previously accrued service. To calculate the expected return on pension plan assets, the Company uses the plan assets' market-related value and an expected long-term rate of return. For the majority of the Company's pension plans, the fair market value of the assets at the balance sheet date is adjusted to a market-related value by recognizing the change in fair value experienced in a given year ratably over a five-year period. Interest cost represents the annual accretion of the PBO and APBO at the discount rate. Actuarial gains and losses outside of a corridor (equal to 10 percent of the greater of the benefit obligation and the market-related value of assets) are amortized over the expected future working lifetime of active participants (except for plans where almost all participants are inactive). Prior service costs related to plan changes are amortized over the expected future working lifetime (or to full eligibility date for postretirement plan other than pensions) of the active participants at the time of the amendment.

Asset Retirement Obligations

A portion of removal costs related to interim retirements of gas utility pipeline and utility poles, certain asbestos-related issues, and reclamation activities meet the definition of an asset retirement obligation (ARO). The Company records the fair value of a liability for a legal ARO in the period in which it is incurred. When the liability is initially recorded, the Company capitalizes a cost by increasing the carrying amount of the related long-lived asset. The liability is accreted, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company settles the obligation for its recorded amount or incurs a gain or loss. To the extent regulation is involved, regulatory assets and liabilities result when accretion and amortization is adjusted to match rates established by regulators and any gain or loss is subject to deferral.

Product Warranties, Performance Guarantees & Other Guarantees

Liabilities and expenses associated with product warranties and performance guarantees are recognized based on historical experience at the time the associated revenue is recognized. Adjustments are made as changes become reasonably estimable. The Company does not recognize the fair value of an obligation at inception for these guarantees because they are guarantees of the Company's own performance and/or product installations.

While not significant for the periods presented, the Company does recognize the fair value of an obligation at the inception of a guarantee in certain circumstances. These circumstances would include executing certain indemnification agreements and guaranteeing operating lease residual values, the performance of a third party, or the indebtedness of a third party.

Energy Contracts & Derivatives

The Company will periodically execute derivative contracts in the normal course of operations while buying and selling commodities to be used in operations, optimizing its generation assets, and managing risk. A derivative is recognized on the balance sheet as an asset or liability measured at its fair market value and the change in the derivative's fair market value is recognized currently in earnings unless specific hedge criteria are met.

When an energy contract that is a derivative is designated and documented as a normal purchase or normal sale (NPNS), it is exempt from mark-to-market accounting. Most energy contracts executed by the Company are subject to the NPNS exclusion or are not considered derivatives. Such energy contracts include Real Time and Day Ahead purchase and sale contracts with the MISO, natural gas purchases, and wind farm and other electric generating contracts.

When the Company engages in energy contracts and financial contracts that are derivatives and are not subject to the NPNS or other exclusions, such contracts are recorded at market value as current or noncurrent assets or liabilities depending on their value and when the contracts are expected to be settled. Contracts and any associated collateral with counter-parties subject to master netting arrangements are presented net in the Consolidated Balance Sheets. The offset resulting from carrying the derivative at fair value on the balance sheet is charged to earnings unless it qualifies as a hedge or is subject to regulatory accounting treatment. When hedge accounting is appropriate, the Company assesses and documents hedging relationships between the derivative contract and underlying risks as well as its risk management objectives and anticipated effectiveness. When the hedging relationship is highly effective, derivatives are designated as hedges. The market value of the effective portion of the hedge is marked to market in Accumulated other comprehensive income for cash flow hedges. Ineffective portions of hedging arrangements are marked to market through earnings. For fair value hedges, both the derivative and the underlying hedged item are marked to market through earnings. The offset to contracts affected by regulatory accounting treatment are marked to market as a regulatory asset or liability. Market value for derivative contracts is determined using quoted market prices from independent sources. The Company rarely enters into contracts that have a significant impact to the financial statements where internal models are used to calculate fair value. As of and for the periods presented, related derivative activity is not material to these financial statements.

Income Taxes
Deferred income taxes are provided for temporary differences between the tax basis (adjusted for related unrecognized tax benefits, if any) of an asset or liability and its reported amount in the financial statements. Deferred tax assets and liabilities are computed based on the currently-enacted statutory income tax rates that are expected to be applicable when the temporary differences are scheduled to reverse. The Company's rate regulated utilities recognize regulatory liabilities for deferred taxes provided in excess of the current statutory tax rate and regulatory assets for deferred taxes provided at rates less than the current statutory tax rate. Such tax-related regulatory assets and liabilities are reported at the revenue requirement level and amortized to income as the related temporary differences reverse, generally over the lives of the related properties. A valuation allowance is recorded to reduce the carrying amounts of deferred tax assets unless it is more likely than not that the deferred tax assets will be realized.

Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the more-likely-than-not recognition threshold is satisfied and measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement. The Company reports interest and penalties associated with unrecognized tax benefits within Income taxes in the Consolidated Statements of Income and reports tax liabilities related to unrecognized tax benefits as part of Deferred credits & other liabilities.

Investment tax credits (ITCs) are deferred and amortized to income over the approximate lives of the related property. Production tax credits (PTCs) are recognized as energy is generated and sold based on a per kilowatt hour rate prescribed in applicable federal and state statutes.

Revenues
Most revenues are recognized as products and services are delivered to customers. Some nonutility revenues are recognized using the percentage of completion method. The Company records revenues for services and goods delivered but not billed at the end of an accounting period in Accrued unbilled revenues.

MISO Transactions
With the IURC's approval, the Company is a member of the MISO, a FERC approved regional transmission organization. The MISO serves the electrical transmission needs of much of the Midcontinent region and maintains operational control over the Company's electric transmission facilities as well as that of other utilities in the region. The Company is an active participant in the MISO energy markets, bidding its owned generation into the Day Ahead and Real Time markets and procuring power for its retail customers at Locational Marginal Pricing (LMP) as determined by the MISO market.

MISO-related purchase and sale transactions are recorded using settlement information provided by the MISO. These purchase and sale transactions are accounted for on a net hourly position. Net purchases in a single hour are recorded in Cost of fuel & purchased power and net sales in a single hour are recorded in Electric utility revenues. On occasion, prior period transactions are resettled outside the routine process due to a change in the MISO’s tariff or a material interpretation thereof. Expenses associated with resettlements are recorded once the resettlement is probable and the resettlement amount can be estimated. Revenues associated with resettlements are recognized when the amount is determinable and collectability is reasonably assured.

The Company also receives transmission revenue that results from other members' use of the Company's transmission system. These revenues are also included in Electric utility revenues. Generally, these transmission revenues along with costs charged by the MISO are considered components of base rates and any variance from that included in base rates is recovered from / refunded to retail customers through tracking mechanisms.

Share-Based Compensation

The Company grants share-based awards to certain employees and board members. Liability classified share-based compensation awards are re-measured at the end of each period based on an expected settlement date fair value. Equity classified share-based compensation awards are measured at the grant date, based on the fair value of the award. Expense associated with share-based awards is recognized over the requisite service period, which generally begins on the date the award is granted through the earlier of the date the award vests or the date the employee becomes retirement eligible.

Excise & Utility Receipts Taxes

Excise taxes and a portion of utility receipts taxes are included in rates charged to customers. Accordingly, the Company records these taxes received as a component of operating revenues, which totaled $28.3 million in 2016, $29.4 million in 2015, and $32.3 million in 2014. Expense associated with excise and utility receipts taxes are recorded as a component of Taxes other than income taxes.

Operating Segments

The Company's chief operating decision maker is the Chief Executive Officer. The Company uses net income calculated in accordance with generally accepted accounting principles as its most relevant performance measure. The Company has three operating segments within its Utility Group, three operating segments in its Nonutility Group, and a Corporate and Other segment.

Fair Value Measurements

Certain assets and liabilities are valued and disclosed at fair value. Financial assets include securities held in trust by the Company's pension plans. Nonfinancial assets and liabilities include the initial measurement of an asset retirement obligation or the use of fair value in goodwill, intangible assets, and long-lived assets impairment tests. FASB guidance provides the framework for measuring fair value. That framework provides a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). The three levels of the fair value hierarchy are described as follows:

Level 1	Inputs to the valuation methodology are unadjusted quoted prices for identical assets or liabilities in active markets that the Company has the ability to access.
Level 2	Inputs to the valuation methodology include · quoted prices for similar assets or liabilities in active markets; · quoted prices for identical or similar assets or liabilities in inactive markets; · inputs other than quoted prices that are observable for the asset or liability; · inputs that are derived principally from or corroborated by observable market data by correlation or other means If the asset or liability has a specified (contractual) term, the Level 2 input must be observable for substantially the full term of the asset or liability.
Level 3	Inputs to the valuation methodology are unobservable and significant to the fair value measurement.

The asset or liability's fair value measurement level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. Valuation techniques used maximize the use of observable inputs and minimize the use of unobservable inputs.

3. Utility & Nonutility Plant

The original cost of Utility Plant, together with depreciation rates expressed as a percentage of original cost, follows:

	At December 31,					
(In millions)	2016			2015		
	Original Cost	Depreciation Rates as a Percent of Original Cost		Original Cost	Depreciation Rates as a Percent of Original Cost	
Gas utility plant	$3,627.0	3.4	%	$3,279.7	3.4	%
Electric utility plant	2,799.1	3.4	%	2,695.8	3.3	%
Common utility plant	56.3	3.2	%	55.0	3.2	%
Construction work in progress	63.0	—		59.9	—	
Total original cost	$6,545.4			$6,090.4		

SIGECO and Alcoa Generating Corporation (AGC), a subsidiary of Alcoa, Inc. (Alcoa), own a 300 MW unit at the Warrick Power Plant (Warrick Unit 4) as tenants in common. SIGECO's share of the cost of this unit at December 31, 2016, is $190.4 million with accumulated depreciation totaling $110.8 million. AGC and SIGECO share equally in the cost of operation and output of the unit. SIGECO's share of operating costs is included in Other operating expenses in the Consolidated Statements of Income.

In the first quarter of 2016, Alcoa closed its smelter operations. Historically, on-site generation owned and operated by AGC has been used to provide power to the smelter, as well as other mill operations, which will continue. Generation from Alcoa's share of the Warrick Unit 4 has historically been sold into the MISO market. The Company is actively working with Alcoa on plans related to continued operation of this generation.

Nonutility Plant, net of accumulated depreciation and amortization follows:

	At December 31,	
(In millions)	2016	2015
Computer hardware & software	$121.8	$108.8
Land & buildings	77.9	86.4
Vehicles & equipment	207.4	203.0
All other	16.8	16.4
Nonutility plant - net	$423.9	$414.6

Nonutility Plant is presented net of accumulated depreciation and amortization totaling $460.8 million and $420.3 million as of December 31, 2016 and 2015, respectively. For the years ended December 31, 2016, 2015, and 2014, the Company capitalized interest totaling $1.0 million, $0.4 million, and $0.6 million, respectively, on nonutility plant construction projects.

In 2016, the estimated depreciable lives for certain pieces of equipment at Minnesota Limited, LLC were reevaluated and extended due to a change in service life of the equipment. As a result of this evaluation, the Company extended the estimated useful life of certain pieces of equipment effective January 1 of the current year. The effect of this change in estimate was a reduction of annual depreciation expense of approximately $9.6 million in 2016.

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4. Regulatory Assets & Liabilities

Regulatory Assets
Regulatory assets consist of the following:

	At December 31,	
(In millions)	2016	2015
Future amounts recoverable from ratepayers related to:		
Benefit obligations (See Note 11)	$102.6	$97.3
Net deferred income taxes (See Note 10)	(17.1)	(16.9)
	85.5	80.4
Amounts deferred for future recovery related to:		
Cost recovery riders & other	91.6	54.6
	91.6	54.6
Amounts currently recovered in customer rates related to:		
Loss on reacquired debt & hedging proceeds	24.1	25.8
Indiana authorized trackers	64.2	42.6
Deferred coal costs and other	21.2	28.3
Ohio authorized trackers	22.2	17.6
Other base rate recoveries	—	0.1
	131.7	114.4
Total regulatory assets	$308.8	$249.4

Of the $132 million currently being recovered in customer rates, no amounts are earning a return. The weighted average recovery period of regulatory assets currently being recovered in base rates, which totals $24 million, is 24 years. The remainder of the regulatory assets are being recovered timely through periodic recovery mechanisms. The Company has rate orders for all deferred costs not yet in rates and therefore believes that future recovery is probable.

Assets arising from benefit obligations represent the funded status of retirement plans less amounts previously recognized in the statement of income. The Company records a Regulatory asset for that portion related to its rate regulated utilities. See Note 11.

Regulatory Liabilities
At December 31, 2016 and 2015, the Company has approximately $453.7 million and $433.9 million, respectively, in Regulatory liabilities. Of these amounts most relate to cost of removal obligations.

5. Federal Business Unit Acquisition

On April 1, 2014, the Company, through Energy Systems Group, LLC (ESG), a subsidiary of the Energy Services operating segment, purchased the federal sector energy services unit of Chevron Energy Solutions from Chevron USA, referred to hereafter as the Federal Business Unit (FBU). FBU performs under several long-term operations and maintenance contracts (O&M), and has a construction project sales funnel. Included in the acquisition are several Indefinite Delivery / Indefinite Quantity contracts with federal government entities including Energy Savings Performance Contracts (ESPC) with the U.S. Department of Energy and U.S. Army Corps of Engineers. Also included are long-term O&M contracts with multiple Department of Defense installations. FBU is included in the Company's nonutility Energy Services operating segment.

The acquisition purchase price was $42.1 million, which included contingent consideration to be paid if certain new order targets were met in 2014. Those new order targets were not met in 2014 and therefore the contingent consideration was not earned. As such, the contingent consideration liability as of December 31, 2014 of $14.8 million was reversed as operating income. The initial new order target at the end of 2014 was dependent on the signing of contracts with sufficient revenue to meet the threshold. A single contract was targeted that would have been sufficient to meet the threshold but the signing of that contract was delayed by the customer. That contract was signed in August 2015.

Transaction costs associated with the acquisition and expensed by the Company totaled approximately $1.7 million, of which $0.8 million and $0.9 million are included in other operating expenses during the years ended December 31, 2014 and 2013, respectively. For the period from April 1, 2014 through December 31, 2014, FBU contributed an immaterial amount of revenue and net loss to the Company's revenue and net income.

For the year ended December 2014, unaudited proforma results of the combined companies, assuming the acquisition closed on January 1, 2014, would have added approximately $17.7 million to consolidated revenues. The impact to net income and earnings per share would have been de minimis. These proforma results may not be indicative of what actual results would have been if the acquisition had taken place on the proforma date or of future results.

6. Sale of Vectren Fuels, Inc. (Vectren Fuels)

On August 29, 2014 the Company sold its wholly owned coal mining subsidiary, Vectren Fuels, to Sunrise Coal, LLC (Sunrise Coal), an Indiana-based wholly owned subsidiary of Hallador Energy Company. Total cash received was approximately $311 million. The pre-tax loss on disposition of $32 million was reflected in the Consolidated Statement of Income as a $42 million charge to other operating expense, offset by $10 million in lower depreciation expense as depreciation for the assets ceased upon the announcement of the transaction on June 30, 2014. Results from Coal Mining for the year ended December 31, 2014, inclusive of the loss on sale, was a loss of $21.1 million, net of tax. The transaction did not meet the requirements under GAAP to qualify as discontinued operations since Vectren has significant continuing cash flows related to the purchase of coal from the buyer of these mines.

7. Investment in ProLiance Holdings, LLC

The Company has an investment in ProLiance Holdings, LLC (ProLiance or ProLiance Holdings), an affiliate of the Company and Citizens Energy Group (Citizens). Much of the ProLiance business was sold on June 18, 2013 when ProLiance exited the natural gas marketing business through the disposition of certain of the net assets of its energy marketing business, ProLiance Energy, LLC. The Company's remaining investment in ProLiance relates primarily to an investment in LA Storage, LLC (LA Storage). Consistent with its ownership percentage, the Company is allocated 61 percent of ProLiance’s profits and losses; however, governance and voting rights remain at 50 percent for each member, and therefore, the Company accounts for its investment in ProLiance using the equity method of accounting.

The Company's remaining investment at December 31, 2016, shown at its 61 percent ownership share of the individual net assets of ProLiance, is as follows.

(In millions)	As of December 31, 2016
Cash	$ 1.6
Investment in LA Storage	22.4
Other midstream asset investment	5.3
Total investment in ProLiance	$ 29.3
Included in:	
Investments in unconsolidated affiliates	19.2
Other nonutility investments	10.1

LA Storage, LLC Storage Asset Investment

ProLiance Transportation and Storage, LLC (PT&S), a subsidiary of ProLiance, and Sempra Energy International (SEI), a subsidiary of Sempra Energy (SE), through a joint venture, have a 100 percent interest in a development project for salt-cavern natural gas storage facilities known as LA Storage. PT&S is the minority member with an approximate 25 percent interest, which it accounts for using the equity method. The project, which includes a pipeline system, is expected to include 12-19 Bcf of storage capacity, and has the potential for further expansion. This pipeline system is currently connected with several interstate pipelines, including the Cameron Interstate Pipeline operated by Sempra Pipelines & Storage, and can connect area liquefied natural gas regasification terminals to an interstate natural gas transmission system and storage facilities.

Approximately 12 Bcf of the storage, which comprises three of the four FERC certified caverns, is fully tested but additional work is required to further develop the caverns. The timing and extent of development of these caverns and pipeline system is dependent on market conditions, including pricing, need for storage and transmission capacity, and development of the liquefied natural gas market, among other factors. To date, development activity has been modest due to the current low demand for storage facilities. The development of the storage market and related pricing are critical assumptions in the analysis of the recoverability of the investment's carrying value. At December 31, 2016 and 2015, ProLiance's investment in the joint venture was $36.7 million and $36.4 million, respectively.

8. Nonutility Legacy Holdings

Within the nonutility group, there are legacy investments involved in other ventures. As of both December 31, 2016 and 2015, total remaining legacy investments, other than the investment in ProLiance, included in the Other Businesses portfolio totaled $7.0 million.

During 2015, the Company sold its investment in commercial real estate property as well as an interest in a leveraged lease for approximate book value. For the period presented, the remaining investment relates to a debt security related to the sale of commercial real estate of $5.1 million and other investments of $1.9 million.

9. Intangible Assets

Intangible assets, which are included in Other assets, consist of the following:

(In millions)	At December 31,			
	2016		2015	
	Amortizing	Non-amortizing	Amortizing	Non-amortizing
Customer-related assets	$20.9	$ —	$23.1	$ —
Market-related assets	—	13.0	0.2	13.0
Intangible assets, net	$20.9	$ 13.0	$23.3	$ 13.0

As of December 31, 2016, the weighted average remaining life for amortizing customer-related assets is 11 years. These amortizing intangible assets have no significant residual values. Intangible assets are presented net of accumulated amortization totaling $12.0 million for customer-related assets and $4.5 million for market-related assets at December 31, 2016 and $9.8 million for customer-related assets and $4.3 million for market-related assets at December 31, 2015. Annual amortization associated with intangible assets totaled $2.5 million in 2016, $3.1 million in 2015 and $2.8 million in 2014. Amortization should approximate (in millions) $2.6, $2.6, $2.6, $2.6, and $2.6 in 2017, 2018, 2019, 2020, and 2021, respectively. Intangible assets are primarily in the Nonutility Group.

10. Income Taxes

A reconciliation of the federal statutory rate to the effective income tax rate follows:

	Year Ended December 31,		
	2016	2015	2014
Statutory rate:	35.0 %	35.0 %	35.0 %
State & local taxes-net of federal benefit	2.8	3.6	4.1
Amortization of investment tax credit	(0.3)	(0.2)	(0.3)
Depletion	—	—	(2.6)
Domestic production deduction	(0.4)	(1.0)	(1.1)
Energy efficiency building deductions	(1.7)	(2.3)	(1.6)
Research and development credit	(0.6)	(1.6)	(0.3)
Other tax credits	(0.1)	(0.1)	(0.2)
All other-net	0.1	0.2	(0.3)
Effective tax rate	34.8 %	33.6 %	32.7 %

Significant components of the net deferred tax liability follow:

	At December 31,	
(In millions)	2016	2015
Noncurrent deferred tax liabilities (assets):		
Depreciation & cost recovery timing differences	$902.4	$827.6
Regulatory assets recoverable through future rates	17.6	31.6
Alternative minimum tax carryforward	(29.3)	(34.5)
Employee benefit obligations	(8.1)	(9.3)
Net operating loss & other carryforwards	(3.2)	(3.7)
Regulatory liabilities to be settled through future rates	(15.9)	(29.9)
Impairments	(2.5)	(3.0)
Deferred fuel costs-net	25.9	14.2
Other-net	18.8	12.4
Net noncurrent deferred tax liability	$905.7	$805.4

At December 31, 2016 and 2015, investment tax credits totaling $1.6 million and $4.1 million respectively, are included in Deferred credits & other liabilities. At December 31, 2016, the Company has alternative minimum tax carryforwards which do not expire. In addition, the Company has $3.2 million in net operating loss and general business credit carryforwards, which will expire in 5 to 20 years. The net operating loss carryforward and other carryforwards were reduced for the impacts of unrecognized tax benefits and a valuation allowance relating primarily to state net operating loss carryforwards. At December 31, 2016 and 2015, the valuation allowance was $8.3 million and $8.1 million, respectively.

The components of income tax expense follow:

	Year Ended December 31,		
(In millions)	2016	2015	2014
Current:			
Federal	$6.8	$10.8	$24.7
State	6.0	8.5	18.5
Total current taxes	12.8	19.3	43.2
Deferred:			
Federal	97.6	79.0	42.7
State	3.6	2.0	(4.2)
Total deferred taxes	101.2	81.0	38.5
Amortization of investment tax credits	(1.1)	(0.6)	(0.6)
Total income tax expense	$112.9	$99.7	$81.1

Uncertain Tax Positions

Unrecognized tax benefits for all periods presented were not material to the Company. The net liability on the Consolidated Balance Sheet for unrecognized tax benefits inclusive of interest and penalties totaled $1.2 million and $0.9 million, respectively, at December 31, 2016 and 2015.

The Company and/or certain of its subsidiaries file income tax returns in the U.S. federal jurisdiction and various states. The Internal Revenue Service (IRS) has concluded examinations of the Company's U.S. federal income tax returns for tax years through December 31, 2012. The State of Indiana, the Company's primary state tax jurisdiction, has conducted examinations of state income tax returns for tax years through December 31, 2010. The statutes of limitations for assessment of federal income tax and Indiana income tax have expired with respect to tax years through 2012 except to the extent of refunds claimed on amended tax returns. The statutes of limitations for assessment of the 2009, 2011 and 2012 tax years related to the amended Indiana income tax returns will expire in 2018 and 2019.

Indiana Senate Bill 1

In March 2014, Indiana Senate Bill 1 was signed into law. This legislation phases in a 1.6 percent rate reduction to the Indiana Adjusted Gross Income Tax Rate for corporations over a six year period. Pursuant to this legislation, the tax rate will be lowered by 0.25 percent each year for the first five years and 0.35 percent in year six beginning on July 1, 2016 to the final rate of 4.9 percent effective July 1, 2021. Pursuant to FASB guidance, the Company accounted for the effect of the change in tax law on its deferred taxes in the first quarter of 2014, the period of enactment. The impact was not material to results of operations.

11. Retirement Plans & Other Postretirement Benefits

At December 31, 2016, the Company maintains three closed qualified defined benefit pension plans, a nonqualified supplemental executive retirement plan (SERP), and a postretirement benefit plan. The defined benefit pension plans and postretirement benefit plan, which cover eligible full-time regular employees, are primarily noncontributory. The postretirement health care and life insurance plans are a combination of self-insured and fully insured plans. The qualified pension plans and the SERP are aggregated under the heading “Pension Benefits.” The postretirement benefit plan is presented under the heading “Other Benefits.”

Net Periodic Benefit Costs

A summary of the components of net periodic benefit cost for the three years ended December 31, 2016 follows:

	Pension Benefits			Other Benefits		
(In millions)	2016	2015	2014	2016	2015	2014
Service cost	$7.0	$7.9	$7.4	$0.3	$0.4	$0.4
Interest cost	14.7	14.6	15.5	1.7	2.0	2.3
Expected return on plan assets	(22.8)	(22.5)	(22.7)	—	—	—
Amortization of prior service cost (benefit)	0.4	0.7	1.0	(2.9)	(3.0)	(3.0)
Amortization of actuarial loss	7.2	8.5	5.0	—	0.7	0.4
Settlement charge	—	0.6	3.1	—	—	—
Net periodic benefit cost (benefit)	$6.5	$9.8	$9.3	$(0.9)	$0.1	$0.1

A portion of the net periodic benefit cost disclosed in the table above is capitalized as Utility Plant following the allocation of current employee labor costs. Costs capitalized in 2016, 2015, and 2014 are estimated at $1.9 million, $3.1 million, and $2.8 million, respectively.

The Company increased the discount rate used to measure periodic cost from 4.05 percent in 2015 to 4.31 percent in 2016 due to higher benchmark interest rates that approximated the expected duration of the Company's benefit obligations as of that valuation date. The Company derives its discount rate by identifying a theoretical settlement portfolio of high quality corporate bonds sufficient to provide for the plans' projected benefit payments. For fiscal year 2017, the weighted average discount rate assumption will decrease to 4.07 percent for the defined benefit pension plans, based on decreased benchmark interest rates.

The weighted averages of significant assumptions used to determine net periodic benefit costs follow:

	Pension Benefits			Other Benefits		
	2016	2015	2014	2016	2015	2014
Discount rate	4.31%	4.05%	4.74%	4.21%	3.95%	4.66%
Rate of compensation increase	3.50%	3.50%	3.50%	N/A	N/A	N/A
Expected return on plan assets	7.50%	7.50%	7.75%	N/A	N/A	N/A
Expected increase in Consumer Price Index	N/A	N/A	N/A	2.50%	2.50%	2.75%

The Company uses a "building block" approach to develop an expected long-term rate of return. For fiscal year 2017, the Company has lowered the expected return on plan assets from 7.50 percent to 7.0 percent based on this approach. Health care cost trend rate assumptions do not have a material effect on the service and interest cost components of benefit costs. The Company's plans limit its exposure to increases in health care costs to annual changes in the Consumer Price Index (CPI). Any increase in health care costs in excess of the CPI increase is the responsibility of the plan participants.

Benefit Obligations

A reconciliation of the Company's benefit obligations at December 31, 2016 and 2015 follows:

	Pension Benefits		Other Benefits	
(In millions)	2016	2015	2016	2015
Benefit obligation, beginning of period	$348.3	$371.9	$43.5	$53.3
Service cost – benefits earned during the period	7.0	7.9	0.3	0.4
Interest cost on projected benefit obligation	14.7	14.6	1.7	2.0
Plan participants' contributions	—	—	1.1	1.0
Plan amendments	—	0.5	—	—
Actuarial loss (gain)	8.7	(17.0)	(1.6)	(8.6)
Benefit payments	(28.3)	(27.9)	(4.5)	(4.6)

Settlement payments	—	(1.7)	—	—
Benefit obligation, end of period	$350.4	$348.3	$40.5	$43.5

The accumulated benefit obligation for all defined benefit pension plans was $339.8 million and $336.1 million at December 31, 2016 and 2015, respectively. The increase in the pension benefit obligation in 2016 is primarily due to a decrease in the discount rate used to measure the obligation at year end.

Mortality Assumption Changes
In October 2014, the Society of Actuaries (SOA) released updated mortality estimates that reflect increased life expectancy. The Company updated its mortality assumptions to incorporate this increase in life expectancy. Accordingly, the Company updated its base mortality assumption to the SOA 2014 table as well as updated its projected mortality improvement. In October 2015 and 2016, the SOA released updated projected mortality improvement that reflect additional years of data. The Company continues to use the SOA 2014 base table and has updated to the projected mortality improvement data that was released in 2015 and 2016, respectively. These changes are reflected in the Company's benefit obligation as of December 31, 2016.

Other Material Assumptions
The benefit obligation as of December 31, 2016 and 2015 was calculated using the following weighted average assumptions:

	Pension Benefits		Other Benefits	
	2016	2015	2016	2015
Discount rate	4.07%	4.31%	4.04%	4.21%
Rate of compensation increase	3.50%	3.50%	N/A	N/A
Expected increase in Consumer Price Index	N/A	N/A	2.50%	2.50%

To calculate the 2016 ending postretirement benefit obligation, medical claims costs in 2017 were assumed to be 5.5 percent higher than those incurred in 2016. That trend, beginning at 8.0 percent in 2012, was assumed to reach its ultimate trending increase of 5.0 percent by 2018 and remain level thereafter. A one-percentage point change in assumed health care cost trend rates would have changed the benefit obligation by approximately $0.2 million.

Plan Assets
A reconciliation of the Company’s plan assets at December 31, 2016 and 2015 follows:

	Pension Benefits		Other Benefits	
(In millions)	2016	2015	2016	2015
Plan assets at fair value, beginning of period	$296.9	$305.6	$ —	$ —
Actual return on plan assets	19.7	(2.0)	—	—
Employer contributions	16.2	22.9	3.4	3.6
Plan participants' contributions	—	—	1.1	1.0
Benefit payments	(28.3)	(27.9)	(4.5)	(4.6)
Settlement payments	—	(1.7)	—	—
Fair value of plan assets, end of period	$304.5	$296.9	$ —	$ —

The Company’s overall investment strategy for its retirement plan trusts is to maintain investments in a diversified portfolio, comprised of primarily equity and fixed income investments, which are further diversified among various asset classes. The diversification is designed to minimize the risk of large losses while maximizing total return within reasonable and prudent levels of risk. The investment objectives specify a targeted investment allocation for the pension plans of 62 percent equities, 35 percent debt, and 3 percent for other investments, including real estate. Both the equity and debt securities have a blend of domestic and international exposures. Objectives do not target a specific return by asset class. The portfolios’ return is monitored in total. Following is a description of the valuation methodologies used for trust assets measured at fair value.

Mutual Funds
The fair values of mutual funds are derived from the daily closing price as reported by the fund as these instruments have active markets (Level 1 inputs).

Common Collective Trust Funds (CTF’s)
The Company’s plans have investments in trust funds similar to mutual funds in that they are created by pooling of funds from investors into a common trust and such funds are managed by a third party investment manager. These trust funds typically give investors a wider range of investment options through this pooling of funds than those generally available to investors on an individual basis. However, unlike mutual funds, these trusts are not publicly traded in an active market. The funds are valued at the net asset value of the underlying investments. The net asset value is used as a practical expedient to estimate fair value. In relation to these investments, there are no unfunded commitments. Also, the Plan can exchange shares with minimal restrictions, however, certain events may exist where share exchanges are restricted for up to 31 days.

In 2015, FASB issued Accounting Standards Update No. 2015-07, Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent). In accordance with this guidance, investments measured at net asset value per share as a practical expedient are no longer categorized within in the fair value hierarchy as shown in the tables below. The update was effective for plan years beginning after December 15, 2015. This change was applied retrospectively to all periods presented.

The fair values of the Company’s pension and other retirement plan assets at December 31, 2016 and December 31, 2015 by asset category and by fair value hierarchy are as follows:

	As of December 31, 2016			
(In millions)	Level 1	Level 2	Level 3	Total
Domestic equities & equity funds	$135.1	$ —	$ —	$135.1
International equities & equity funds	42.0	—	—	42.0
Domestic bonds & bond funds	44.6	—	—	44.6
Real estate, commodities & other	6.0	—	4.4	10.4
Investments measured at net asset value (a)	—	—	—	72.4
Total plan investments	$227.7	$ —	$ 4.4	$304.5

	As of December 31, 2015			
(In millions)	Level 1	Level 2	Level 3	Total
Domestic equities & equity funds	$113.5	$ —	$ —	$113.5
International equities & equity funds	38.2	—	—	38.2
Domestic bonds & bond funds	36.6	—	—	36.6
Real estate, commodities & other	4.8	—	4.3	9.1
Investments measured at net asset value (a)	—	—	—	99.5
Total plan investments	$193.1	$ —	$ 4.3	$296.9

(a) In accordance with Subtopic 820-10, certain investments that were measured at net asset value per share, or its equivalent, have not been classified in the fair value hierarchy.

Investments Measured Using the Net Asset Value per Share Practical Expedient
The Company's Plans invest in certain common trust funds for which fair value is measured using the net asset value per share practical expedient. The fair value of those funds totaled $72.4 million and $99.5 million as of December 31, 2016 and 2015, respectively.

Guaranteed Annuity Contract
One of the Company’s pension plans is party to a group annuity contract with John Hancock Life Insurance Company (John Hancock). At December 31, 2016 and 2015, the estimate of undiscounted funds necessary to satisfy John

Hancock's remaining obligation was $4.0 million and $3.9 million, respectively. If funds retained by John Hancock are not sufficient to satisfy retirement payments due to these retirees, the shortfall must be funded by the Company. The composite investment return, net of manager fees and other charges for the years ended December 31, 2016 and 2015 was 3.60 percent and 3.65 percent, respectively. The Company values this illiquid investment using long-term interest rate and mortality assumptions, among others, and is therefore considered a Level 3 investment. There is no unfunded commitment related to this investment.

A roll forward of the fair value of the guaranteed annuity contract calculated using Level 3 valuation assumptions follows:

(In millions)	2016	2015
Fair value, beginning of year	$4.3	$4.2
Unrealized gains related to investments still held at reporting date	0.2	0.2
Purchases, sales & settlements, net	(0.1)	(0.1)
Fair value, end of year	$4.4	$4.3

Funded Status

The funded status of the plans as of December 31, 2016 and 2015 follows:

	Pension Benefits		Other Benefits	
(In millions)	2016	2015	2016	2015
Qualified Plans				
Benefit obligation, end of period	$(329.7)	$(328.7)	$(40.5)	$(43.5)
Fair value of plan assets, end of period	304.5	296.9	—	—
Funded Status of Qualified Plans, end of period	(25.2)	(31.8)	(40.5)	(43.5)
Benefit obligation of SERP Plan, end of period	(20.6)	(19.6)	—	—
Total funded status, end of period	$(45.8)	$(51.4)	$(40.5)	$(43.5)
Accrued liabilities	$1.2	$1.2	$4.5	$4.6
Deferred credits & other liabilities	$44.6	$50.2	$36.0	$38.9

Expected Cash Flows

The Company currently does not anticipate making a contribution to the qualified pension plans in 2017. In addition, the Company expects to make contributions totaling approximately $1.2 million into the SERP plan and approximately $3.1 million into the postretirement plan.

Estimated retiree pension benefit payments, including the SERP, projected to be required during the years following 2016 are approximately (in millions) $26.3 in 2017, $38.0 in 2018, $26.8 in 2019, $29.1 in 2020, $26.6 in 2021, and $132.4 in years 2022-2026. Expected benefit payments projected to be required for postretirement benefits during the years following 2016 (in millions) are approximately $4.5 in 2017, $4.6 in 2018, $4.7 in 2019, $5.0 in 2020, $5.1 in 2021, and $24.0 in years 2022-2026.

Prior Service Cost, Actuarial Gains and Losses, and Transition Obligation Effects

Following is a roll forward of prior service cost and actuarial gains and losses.

	Pensions		Other Benefits	
(In millions)	Prior Service Cost	Net Gain or Loss	Prior Service Cost	Net Gain or Loss
Balance at January 1, 2014	$3.0	$67.3	$(20.1)	$8.1
Amounts arising during the period	—	49.4	—	3.2
Reclassification to benefit costs	(1.0)	(5.0)	3.0	(0.4)
Balance at December 31, 2014	$2.0	$111.7	$(17.1)	$10.9
Amounts arising during the period	0.5	6.9	—	(8.6)
Reclassification to benefit costs	(0.7)	(8.5)	3.0	(0.7)
Balance at December 31, 2015	$1.8	$110.1	$(14.1)	$1.6
Amounts arising during the period	—	11.7	—	(1.6)

Reclassification to benefit costs	(0.4)	(7.2)	2.9	—
Balance at December 31, 2016	$1.4	$114.6	$(11.2)	$—

Following is a reconciliation of the amounts in Accumulated other comprehensive income (AOCI) and Regulatory assets related to retirement plan obligations at December 31, 2016 and 2015.

(In millions)	2016		2015	
	Pensions	Other Benefits	Pensions	Other Benefits
Prior service cost	$1.4	$(11.2)	$1.8	$(14.1)
Unamortized actuarial gain/(loss)	114.6	—	110.1	1.6
	116.0	(11.2)	111.9	(12.5)
Less: Regulatory asset deferral	(113.6)	11.0	(109.6)	12.3
AOCI before taxes	$2.4	$(0.2)	$2.3	$(0.2)

Related to pension plans, $0.4 million of prior service cost and $7.6 million of actuarial gain/loss is expected to be amortized to cost in 2017. Related to other benefits, no actuarial gain/loss is expected to be amortized to periodic cost in 2017, and $2.4 million of prior service cost is expected to reduce costs in 2017.

Multiemployer Benefit Plan

The Company, through its Infrastructure Services operating segment, participates in several industry wide multiemployer pension plans for its union employees which provide for monthly benefits based on length of service. The risks of participating in multiemployer pension plans are different from the risks of participating in single-employer pension plans in the following respects: 1) assets contributed to the multiemployer plan by one employer may be used to provide benefits to employees of other participating employers, 2) if a participating employer stops contributing to the plan, the unfunded obligations of the plan allocable to such withdrawing employer may be borne by the remaining participating employers, and 3) if the Company stops participating in some of its multiemployer pension plans, the Company may be required to pay those plans an amount based on its allocable share of the underfunded status of the plan, referred to as a withdrawal liability.

Expense is recognized as payments are accrued for work performed or when withdrawal liabilities are probable and estimable. Expense associated with multiemployer plans was $35.0 million, $32.7 million and $32.4 million for the years ended December 31, 2016, 2015, and 2014, respectively. During 2016, the Company made contributions to these multiemployer plans on behalf of employees that participate in approximately 280 local unions. Contracts with these unions are negotiated with trade agreements through two primary contractor associations. These trade agreements have varying expiration dates ranging from 2017 through 2021. The average contribution related to these local unions was less than $0.2 million, and the largest contribution was $2.9 million. Multiple unions can contribute to a single multiemployer plan. The Company made contributions to at least 60 plans in 2016, six of which are considered significant plans based on, among other things, the amount of the contributions, the number of employees participating in the plan, and the funded status of the plan.

The Company's participation in the significant plans is outlined in the following table. The Employer Identification Number (EIN) / Pension Plan Number column provides the EIN and three digit pension plan numbers. The most recent Pension Protection Act Zone Status available in 2016 and 2015 is for the plan year end at February 1, 2015 and 2014 for the Central Pension Fund, January 1, 2015 and 2014 for the Pipeline Industry Benefit Fund, June 1, 2015 and 2014 for the Indiana Laborers Pension Fund, August 1, 2015 and 2014 for the Ohio Operating Engineers Pension Fund, January 1, 2015 and 2014 for the Minnesota Laborers Pension Fund, and January 1, 2015 and 2014 for the Laborers District Fund of Ohio, respectively. Generally, plans in the red zone are less than 65 percent funded, plans in the yellow zone are less than 80 percent funded and plans in the green zone are at least 80 percent funded. The FIP/RP Status Pending / Implemented column indicates plans for which a funding improvement plan ("FIP") or rehabilitation plan ("RP") is either pending or has been implemented. The multiemployer contributions listed in the table below are the Company's multiemployer contributions made in 2016, 2015, and 2014.

(In millions)

Pension Fund	EIN/Pension Plan Number	Pension Protection Act Zone Status		FIP/RP Status Pending/Implemented	Multiemployer Contributions			Surcharge Imposed
		2016	2015		2016	2015	2014	
Central Pension Fund	36-6052390-001	Green	Green	No	$7.4	$7.2	$7.7	No
Pipeline Industry Benefit Fund	73-0742835-001	Green	Green	No	3.0	4.0	5.1	No
Indiana Laborers Pension Fund (1)	35-6027150-001	Yellow	Yellow	Implemented	4.4	4.1	3.5	No
Ohio Operating Engineers Pension Fund	31-6129968-001	Green	Green	No	2.1	2.2	1.7	No
Minnesota Laborers Pension Fund	41-6159599-001	Green	Green	No	1.2	1.8	2.2	No
Laborers District Fund of Ohio	31-6129964-001	Green	Green	No	2.0	1.5	1.1	No
Other					14.9	11.9	11.1	
Total Contributions					$35.0	$32.7	$32.4	

(1) Federal law requires pension plans in endangered status to adopt a FIP aimed at restoring the financial health of the plan. In December 2014, the Multiemployer Pension Reform Act of 2014 was passed and permanently extended the Pension Protection Act of 2006 multiemployer plan critical and endangered status funding rules, among other things, including providing a provision for a plan sponsor to suspend or reduce benefit payments to preserve plans in critical and declining status. The Indiana Laborers Pension Fund (Fund) was not in "critical" status but rather in an “endangered” status in the Plan Year ending May 31, 2016 because of a funded ratio of 72 percent, no projected funding deficiency in the funding standard account, at least 8 years of benefit payments within plan assets and other results. In an effort to improve the Plan’s funding situation, the trustees adopted a FIP on December 17, 2015. The funding improvement period is June 1, 2017 to May 31, 2027 or the date the Fund’s actuary certifies it has emerged from endangered status.

While not considered significant to the Company, there are nine plans in red zone status receiving Company contributions. There are seven plans where Company contributions exceed 5 percent of each plan's total contributions and two of these plans were considered significant to the Company (Pipeline Industry Benefit Fund and Indiana Laborers Pension Fund).

Defined Contribution Plan

The Company also has defined contribution retirement savings plans qualified under sections 401(a) and 401(k) of the Internal Revenue Code and include an option to invest in Vectren common stock, among other alternatives. During 2016, 2015 and 2014, the Company made contributions to these plans of $12.1 million, $11.0 million, and $9.1 million, respectively.

12. Borrowing Arrangements

Long-Term Debt

Long-term senior unsecured obligations and first mortgage bonds outstanding by subsidiary follow:

	At December 31,	
(In millions)	2016	2015
Utility Holdings		
Fixed Rate Senior Unsecured Notes		
2018, 5.75%	$100.0	$100.0
2020, 6.28%	100.0	100.0
2021, 4.67%	55.0	55.0
2023, 3.72%	150.0	150.0
2026, 5.02%	60.0	60.0
2028, 3.20%	45.0	45.0
2035, 6.10%	75.0	75.0
2035, 3.90%	25.0	25.0
2041, 5.99%	35.0	35.0
2042, 5.00%	100.0	100.0
2043, 4.25%	80.0	80.0
2045, 4.36%	135.0	135.0
2055, 4.51%	40.0	40.0
Total Utility Holdings	1,000.0	1,000.0
Indiana Gas		
Fixed Rate Senior Unsecured Notes		
2025, Series E, 6.53%	10.0	10.0
2027, Series E, 6.42%	5.0	5.0
2027, Series E, 6.68%	1.0	1.0
2027, Series F, 6.34%	20.0	20.0
2028, Series F, 6.36%	10.0	10.0
2028, Series F, 6.55%	20.0	20.0
2029, Series G, 7.08%	30.0	30.0
Total Indiana Gas	96.0	96.0
SIGECO		
First Mortgage Bonds		
2016, 1986 Series, 8.875%	—	13.0
2022, 2013 Series C, 1.95%, tax-exempt	4.6	4.6
2024, 2013 Series D, 1.95%, tax-exempt	22.5	22.5
2025, 2014 Series B, current adjustable rate 1.045%, tax-exempt	41.3	41.3
2029, 1999 Series, 6.72%	80.0	80.0
2037, 2013 Series E, 1.95%, tax-exempt	22.0	22.0
2038, 2013 Series A, 4.00%, tax-exempt	22.2	22.2
2043, 2013 Series B, 4.05%, tax-exempt	39.6	39.6
2044, 2014 Series A, 4.00% tax-exempt	22.3	22.3
2055, 2015 Series Mt. Vernon, 2.375%, tax-exempt	23.0	23.0
2055, 2015 Series Warrick County, 2.375%, tax-exempt	15.2	15.2
Total SIGECO	292.7	305.7

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(In millions)	At December 31, 2016	2015
Vectren Capital Corp.		
Fixed Rate Senior Unsecured Notes		
2016, 6.92%	$—	$60.0
2017, 3.48%	75.0	75.0
2019, 7.30%	60.0	60.0
2022, 3.33%	75.0	75.0
2025, 4.53%	50.0	50.0
2030, 3.90%	75.0	75.0
Total Vectren Capital Corp.	335.0	395.0
Total long-term debt outstanding	1,723.7	1,796.7
Current maturities of long-term debt	(124.1)	(73.0)
Debt issuance costs	(9.0)	(9.9)
Unamortized debt premium & discount-net	(0.7)	(0.9)
Total long-term debt-net	$1,589.9	$1,712.9

Simplifying the Presentation of Debt Issuance Costs
In April 2015, the FASB issued new accounting guidance on accounting for debt issuance costs which changes the presentation of debt issuance costs in financial statements. This ASU requires an entity to present such costs in the balance sheet as a direct reduction from the related debt liability rather than as an asset. Amortization of the costs will continue to be reported as interest expense. This ASU is effective for annual reporting periods beginning after December 15, 2015. The guidance was adopted as of January 1, 2016 and has been applied retrospectively to all periods presented. The effect of the change on the December 31, 2015 balance sheet was the reclassification of $8.6 million from Regulatory assets to Long-term Debt and the reclassification of $1.3 million from Other assets to Long-term Debt. The reclassification had no material impact on the Company's financial condition, results of operations, or cash flows as a result of the adoption.

Vectren Capital Unsecured Note Retirement
On March 11, 2016, a $60 million Vectren Capital senior unsecured note matured. The Series B note, which was part of a private placement Note Purchase Agreement entered into on March 11, 2009, carried a fixed interest rate of 6.92 percent. The repayment of debt was funded from the Company's cash on hand.

SIGECO Bond Retirement
On June 1, 2016, a $13 million SIGECO bond matured. The First Mortgage Bond, which was a portion of an original $25 million public issuance sold on June 1, 1986, carried a fixed interest rate of 8.875 percent. The repayment of debt was funded from the Company’s commercial paper program.

Indiana Gas Unsecured Note Retirement
On March 15, 2015, a $5 million Indiana Gas senior unsecured note matured. The Series E note carried a fixed interest rate of 7.15 percent. The repayment of debt was funded by the Company's commercial paper program.

SIGECO Debt Issuance
On September 9, 2015, SIGECO completed a $38.2 million tax-exempt first mortgage bond issuance. The principal terms of the two new series of tax-exempt debt are: (i) $23.0 million in Environmental Improvement Revenue Bonds, Series 2015, issued by the City of Mount Vernon, Indiana and (ii) $15.2 million in Environmental Improvement Revenue Bonds, Series 2015, issued by Warrick County, Indiana. Both bonds were sold in a public offering at an initial interest rate of 2.375 percent per annum that is fixed until September 1, 2020 when the bonds will be remarketed. The bonds have a final maturity of September 1, 2055.

Vectren Utility Holdings, Vectren Capital, and Indiana Gas Debt Transactions
On December 15, 2015, Utility Holdings issued Guaranteed Senior Notes in a private placement to various institutional investors in the following tranches: (i) $25 million of 3.90 percent Guaranteed Senior Notes, Series A, due December 15, 2035, (ii) $135 million of 4.36 percent Guaranteed Senior Notes, Series B, due December 15, 2045, and (iii) $40 million of 4.51 percent

Guaranteed Senior Notes, Series C, due December 15, 2055. The notes are unconditionally guaranteed by Indiana Gas, SIGECO and VEDO.

Additionally, on December 15, 2015, Vectren Capital issued Guaranteed Senior Notes in a private placement to various institutional investors in the following tranches: (i) $75 million of 3.33 percent Guaranteed Senior Notes, Series A, due December 15, 2022 and (ii) $75 million of 3.90 percent Guaranteed Senior Notes, Series B, due December 15, 2030. The notes are guaranteed by Vectren Corporation.

A portion of the proceeds received from these issuances were used to finance the following retirements of debt: (i) $75 million of 5.45 percent Utility Holdings senior unsecured notes that matured on December 1, 2015, (ii) $75 million 5.31 percent Vectren Capital senior unsecured notes that matured on December 15, 2015, and (iii) $5 and $10 million of 6.69 percent Indiana Gas senior unsecured notes that matured on December 21, 2015 and December 29, 2015, respectively.

Vectren Capital Unsecured Note Retirement
On March 11, 2014, a $30 million Vectren Capital senior unsecured note matured. The Series A note, which was part of a private placement Note Purchase Agreement entered into on March 11, 2009, carried a fixed interest rate of 6.37 percent. The repayment of debt was funded from the Company's short-term credit facility.

SIGECO Debt Refund and Issuance
On September 24, 2014, SIGECO issued two new series of tax-exempt debt totaling $63.6 million. Proceeds from the issuance were used to retire three series of tax-exempt bonds aggregating $63.6 million at a redemption price of par plus accrued interest. The principal terms of the two new series of tax-exempt debt are: (i) $22.3 million sold in a public offering and bear interest at 4.00 percent per annum, due September 1, 2044 and (ii) $41.3 million, due July 1, 2025, sold in a private placement at variable rates through September 2019.

Mandatory Tenders
At December 31, 2016, certain series of SIGECO bonds, aggregating $87.3 million, currently bear interest at fixed rates, of which $49.1 million is subject to mandatory tender in September 2017 and $38.2 million is subject to mandatory tender in September 2020. Additionally, SIGECO Bond Series 2014B, in the amount of $41.3 million, with a variable interest rate that is reset monthly, is subject to mandatory tender in September 2019.

Future Long-Term Debt Sinking Fund Requirements and Maturities
The annual sinking fund requirement of SIGECO's first mortgage bonds is 1 percent of the greatest amount of bonds outstanding under the Mortgage Indenture. This requirement may be satisfied by certification to the Trustee of unfunded property additions in the prescribed amount as provided in the Mortgage Indenture. SIGECO met the 2016 sinking fund requirement by this means and, expects to also meet this requirement in 2017 in this manner. Accordingly, the sinking fund requirement is excluded from Current liabilities in the Consolidated Balance Sheets. At December 31, 2016, $1.4 billion of SIGECO's utility plant remained unfunded under SIGECO's Mortgage Indenture. SIGECO’s gross utility plant balance subject to the Mortgage Indenture approximated $3.3 billion at December 31, 2016.

Consolidated maturities of long-term debt during the five years following 2016 (in millions) are $124 in 2017, $100 in 2018, $60 in 2019, $100 in 2020, $55 in 2021, and $1,275 thereafter.

Debt Guarantees
Vectren Corporation guarantees Vectren Capital’s debt, but does not guarantee Utility Holdings' debt. Vectren Capital's long-term debt, including current maturities outstanding at December 31, 2016 approximated $334 million. Vectren Capital had no short-term obligations outstanding at December 31, 2016. Utility Holdings’ outstanding long-term and

short-term borrowing arrangements are jointly and severally guaranteed by its wholly owned subsidiaries and regulated utilities Indiana Gas, SIGECO, and VEDO. Utility Holdings' long-term debt and short-term obligations outstanding at December 31, 2016 approximated $996 million and $194 million, respectively.

Covenants
Both long-term and short-term borrowing arrangements contain customary default provisions; restrictions on liens, sale-leaseback transactions, mergers or consolidations, and sales of assets; and restrictions on leverage, among other restrictions. Multiple debt agreements contain a covenant that the ratio of consolidated total debt to consolidated total capitalization will not exceed 65 percent. As of December 31, 2016, the Company was in compliance with all debt covenants.

Short-Term Borrowings
At December 31, 2016, the Company had $600 million of short-term borrowing capacity, including $350 million for the Utility Group and $250 million for the wholly owned Nonutility Group and corporate operations. As reduced by borrowings currently outstanding, approximately $156 million was available for the Utility Group operations and $250 million was available for the wholly owned Nonutility Group and corporate operations. Both Vectren Capital's and Utility Holdings' short-term credit facilities are available through October 31, 2019. These facilities are used to supplement working capital needs and also to fund capital investments and debt redemptions.

The Company has historically funded the short-term borrowing needs of Utility Holdings' operations through the commercial paper market but maintains the ability to use the Utility Holdings' short-term borrowing facility when necessary. Following is certain information regarding these short-term borrowing arrangements.

	Utility Group Borrowings			Nonutility Group Borrowings		
(In millions)	2016	2015	2014	2016	2015	2014
As of Year End						
Balance Outstanding	$194.4	$14.5	$156.4	$—	$—	$—
Weighted Average Interest Rate	1.05 %	0.55 %	0.50 %	N/A	N/A	N/A
Annual Average						
Balance Outstanding	$59.8	$53.8	$35.6	$0.2	$24.8	$34.5
Weighted Average Interest Rate	0.71 %	0.38 %	0.34 %	1.60 %	1.33 %	1.29 %
Maximum Month End Balance Outstanding	$194.4	$121.5	$156.4	$6.3	$69.1	$76.3

Throughout the years presented, Utility Holdings has successfully placed commercial paper as needed.

13. Common Shareholders' Equity

Authorized, Reserved Common and Preferred Shares
At December 31, 2016 and 2015, the Company was authorized to issue 480 million shares of common stock and 20 million shares of preferred stock. Of the authorized common shares, approximately 4.6 million shares at December 31, 2016 and 5.1 million shares at December 31, 2015 were reserved by the board of directors for issuance through the Company's share-based compensation plans, benefit plans, and dividend reinvestment plan. At December 31, 2016 and 2015, there were 392.5 million and 392.1 million, respectively, of authorized shares of common stock and all authorized shares of preferred stock, available for a variety of general corporate purposes, including future public offerings to raise additional capital.

14. Earnings Per Share

The Company uses the two class method to calculate earnings per share (EPS). The two class method is an earnings allocation formula that treats a participating security as having rights to earnings that otherwise would have been available to common shareholders. Under the two class method, earnings for a period are allocated between common shareholders and participating security holders based on their respective rights to receive dividends as if all undistributed book earnings for the period were distributed.

Basic EPS is computed by dividing net income attributable to only the common shareholders by the weighted-average number of common shares outstanding for the period. Diluted EPS includes the impact of stock options and other equity based instruments to the extent the effect is dilutive.

The following table illustrates the basic and dilutive EPS calculations for the three years ended December 31, 2016:

	Year Ended December 31,		
(In millions, except per share data)	2016	2015	2014
Numerator:			
Reported net income (Numerator for Diluted EPS)	$211.6	$197.3	$166.9
Denominator:			
Weighted-average common shares outstanding (Basic and Diluted EPS)	82.8	82.7	82.5
Basic and diluted earnings per share	$2.55	$2.39	$2.02

As of December 31, 2016 the Company no longer has any stock options outstanding and all equity based instruments were dilutive and immaterial. For the years ended December 31, 2015 and 2014, all options and equity based instruments were dilutive and immaterial.

15. Accumulated Other Comprehensive Income

A summary of the components of and changes in Accumulated other comprehensive income for the past three years follows:

	2014			2015		2016	
(In millions)	Beginning of Year Balance	Changes During Year	End of Year Balance	Changes During Year	End of Year Balance	Changes During Year	End of Year Balance
Pension & other benefit costs	(1.2)	(1.0)	(2.2)	0.1	(2.1)	(0.1)	(2.2)
Deferred income taxes	0.5	0.4	0.9	—	0.9	—	0.9
Accumulated other comprehensive income (loss)	$(0.7)	$ (0.6)	$ (1.3)	$0.1	$ (1.2)	$(0.1)	$ (1.3)

16. Share-Based Compensation & Deferred Compensation Arrangements

The Company has share-based compensation programs to encourage corporate and subsidiary officers, key non-officer employees, and non-employee directors to remain with the Company and to more closely align their interests with those of the Company's shareholders. Under these programs, the Company issues both performance-based and time-vested awards. All share-based compensation programs are shareholder approved. Currently, awards issued to a majority of the officers are performance-based, accrue dividends that are also subject to performance measures, and are settled in cash. In addition, the Company maintains a deferred compensation plan for officers and non-employee directors where participants can invest earned compensation and vested share-based awards in phantom Company stock units, among other options. Certain vesting grants provide for accelerated vesting if there is a change in control or upon the participant's retirement.

Following is a reconciliation of the total cost associated with share-based awards recognized in the Company's financial statements to its after tax effect on net income:

Year Ended
December 31,

(In millions)	2016	2015	2014
Total cost of share-based compensation	$30.0	$19.4	$25.2
Less capitalized cost	7.0	4.8	5.3
Total in other operating expense	23.0	14.6	19.9
Less income tax benefit in earnings	9.0	5.7	7.9
After tax effect of share-based compensation	$14.0	$8.9	$12.0

Share-Based Awards & Other Awards
The vesting of awards issued to officers is contingent upon meeting total return and return on equity performance objectives. Historically, grants to officers generally vest at the end of a four-year period, with performance measured at the end of the third year. Grants issued to officers in 2015 and beyond will generally vest at the end of a three-year period, with performance continuing to be measured at the end of the third year. Based on performance objectives, the number of awards could double or could be entirely forfeited.

A limited number of awards to certain subsidiary officers and awards to non-officer employees are time-vested awards, vest ratably over a three or five-year period, and are primarily settled in cash. In addition, non-employee directors receive a portion of their fees in share-based awards. These awards to non-employee directors are not performance-based and generally vest over one year. The majority of officers and non-employee directors must choose between either settling awards in cash or deferring awards into a deferred compensation plan (where the value is eventually withdrawn in cash). A limited number of subsidiary officers may either settle awards in shares or defer awards into a deferred compensation plan at their discretion. The number of such awards that may settle in shares, but are accounted for as liability awards due to their potential to be taken in cash when withdrawn from the deferred compensation plan, was approximately 100,000 units as of December 31, 2016, and less than 100,000 as of December 31, 2015 and 2014.

Most officer, non-officer employee, and non-employee director awards are accounted for as liability awards at their settlement date fair value. The limited number of share awards to certain subsidiary officers that must be settled in shares are accounted for in equity at their grant date fair value.

A summary of the status of awards separated between those accounted for as liabilities and equity as of December 31, 2016 and 2015, and changes during the years ended December 31, 2016 and 2015, follow:

	Equity Awards		Liability Awards	
	Units	Wtd. Avg. Grant Date Fair value	Units	Fair value
Awards at January 1, 2015	34,273	$30.55	693,159	
Granted	13,657	30.39	394,967	
Vested	(29,232)	29.87	(389,331)	
Forfeited	(3,325)	30.95	(52,308)	
Awards at December 31, 2015	15,373	$31.63	646,487	$42.42
Granted	4,052	30.19	448,176	
Vested	(11,711)	30.19	(462,203)	
Forfeited	(1,382)	31.87	(20,880)	
Awards at December 31, 2016	6,332	$33.42	611,580	$52.15

As of December 31, 2016, there was $14.8 million of total unrecognized compensation cost associated with outstanding grants. That cost is expected to be recognized over a weighted-average period of 1.3 years. The total fair value of shares vested for liability awards during the years ended December 31, 2016, 2015, and 2014, was $23.7 million, $16.6 million, and $15.1 million, respectively. The total fair value of equity awards vesting during the years ended December 31, 2016, 2015, and 2014 was $0.6 million, $1.1 million, $0.9 million, respectively.

Deferred Compensation Plans
The Company has nonqualified deferred compensation plans, which permit eligible officers and non-employee directors to defer portions of their compensation and vested share-based compensation. A record keeping account is established for each participant, and the participant chooses from a variety of measurement funds for the deemed investment of their accounts. The measurement funds are similar to the funds in the Company's defined contribution plan and include an investment in phantom stock units of the Company. The account balance fluctuates with the investment returns on those funds. The liability associated with these plans totaled $40.9 million and $31.2 million at December 31, 2016 and 2015, respectively. Other than $0.9 million and $1.4 million which is classified in Accrued liabilities at December 31, 2016 and 2015, respectively, the liability is included in Deferred credits & other liabilities. The impact of these plans on Other operating expenses was expense of $4.3 million in 2016, $0.1 million in 2015 and $5.0 million in 2014. The amount recorded in earnings related to the investment activities in Vectren phantom stock associated with these plans during the years ended December 31, 2016, 2015, and 2014, was cost of $3.8 million, income of $0.4 million, and cost of $4.0 million, respectively.

The Company has certain investments currently funded primarily through corporate-owned life insurance policies. These investments, which are consolidated, are available to pay deferred compensation benefits. These investments are also subject to the claims of the Company's creditors. The cash surrender value of these policies included in Other corporate & utility investments on the Consolidated Balance Sheets were $33.1 million and $30.1 million at December 31, 2016 and 2015, respectively. Those investments generated earnings of $3.5 million in 2016, losses of $2.1 million in 2015, and earnings of $2.8 million in 2014. This activity is reflected in Other income - net.

17. Commitments & Contingencies

Commitments
Future minimum lease payments required under operating leases that have initial or remaining noncancelable lease terms in excess of one year during the five years following 2016 and thereafter (in millions) are $9.8 in 2017, $7.3 in 2018, $4.4 in 2019, $2.1 in 2020, $1.8 in 2021, and $3.9 thereafter. Total lease expense, for these type of commitments, (in millions) was $13.0 in 2016, $11.1 in 2015, and $13.2 in 2014.

The Company’s regulated utilities have both firm and non-firm commitments, some of which are between five and twenty year agreements, to purchase natural gas, coal, and electricity, as well as certain transportation and storage rights. Costs arising from these commitments, while significant, are pass-through costs, generally collected dollar-for-dollar from retail customers through regulator-approved cost recovery mechanisms.

Performance Guarantees & Product Warranties
In the normal course of business, wholly owned subsidiaries, such as Energy Systems Group, LLC (ESG), a subsidiary of the Energy Services operating segment, issue payment and performance bonds and other forms of assurance that commit them to timely install infrastructure, operate facilities, pay vendors and subcontractors, and support warranty obligations.

Specific to ESG's role as a general contractor in the performance contracting industry, at December 31, 2016, there are 54 open surety bonds supporting future performance. The average face amount of these obligations is $10.6 million, and the largest obligation has a face amount of $75.9 million. The maximum exposure from these obligations is limited to the level of uncompleted work and further limited by bonds issued to ESG by various contractors. At December 31, 2016, approximately 43 percent of work was yet to be completed on projects with open surety bonds. A significant portion of these open surety bonds will be released within one year. In instances where ESG operates facilities, project guarantees extend over a longer period. In addition to its performance obligations, ESG also warrants the functionality of certain installed infrastructure generally for one year and the associated energy savings over a specified number of years.

Based on a history of meeting performance obligations and installed products operating effectively, no liability or cost has been recognized for the periods presented as the Company assesses the likelihood of loss as remote. Since inception, ESG has paid a de minimis amount on energy savings guarantees.

Corporate Guarantees

The Company issues parent level guarantees to certain vendors and customers of its wholly owned subsidiaries. These guarantees do not represent incremental consolidated obligations; but rather, represent guarantees of subsidiary obligations in order to allow those subsidiaries the flexibility to conduct business without posting other forms of collateral. At December 31, 2016, parent level guarantees support a maximum of $319 million of ESG's performance contracting commitments, warranty obligations, project guarantees, and energy savings guarantees. Given the infrequent occurrence of any performance shortfalls historically on any of these commitments, no reserve for a potential liability has been deemed warranted.

Further, an energy facility operated by ESG and managed by Keenan Ft. Detrick Energy, LLC (Keenan), is governed by an operations agreement. Under this agreement, all payment obligations to Keenan are also guaranteed by the Company. The Company guarantee of the Keenan operations agreement does not state a maximum guarantee. Due to the nature of work performed under this contract, the Company cannot estimate a maximum potential amount of future payments but assesses the likelihood of loss as remote based on, primarily, the nature of the project.

In addition, the Company has other guarantees outstanding, including letters of credit, supporting other consolidated subsidiary operations.

The Company has not been called on to perform under these guarantees historically. While there can be no assurance that performance under these provisions will not be required in the future, the Company believes that the likelihood of a material amount being incurred under these provisions is remote given the nature of the projects, the manner in which the savings estimates are developed, and the fact that the value of the guarantees decrease over time as actual savings are achieved.

Legal & Regulatory Proceedings

The Company is party to various legal proceedings, audits, and reviews by taxing authorities and other government agencies arising in the normal course of business. In the opinion of management, there are no legal proceedings or other regulatory reviews or audits pending against the Company that are likely to have a material adverse effect on its financial position, results of operations or cash flows.

18. Gas Rate and Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement

The Company monitors and maintains its natural gas distribution system to ensure natural gas is delivered in a safe and efficient manner. The Company's natural gas utilities are currently engaged in programs to replace bare steel and cast iron infrastructure and other activities in both Indiana and Ohio to mitigate risk, improve the system, and comply with applicable regulations, many of which are the result of federal pipeline safety requirements. Laws passed in both Indiana and Ohio provide utilities the opportunity to timely recover costs of federally mandated projects and other infrastructure improvement projects outside of a base rate proceeding.

Indiana Senate Bill 251 (Senate Bill 251) provides a framework to recover 80 percent of federally mandated costs through a periodic rate adjustment mechanism outside of a general rate case. Such costs include a return on the federally mandated capital investment, based on the overall rate of return most recently approved by the IURC, along with recovery of depreciation and other operating costs associated with these mandates. The remaining 20 percent of those costs is deferred for future recovery in the utility's next general rate case.

Indiana Senate Bill 560 (Senate Bill 560) supplements Senate Bill 251 described above, and provides for cost recovery outside of a base rate proceeding for projects that either improve electric and gas system reliability and safety or are economic development projects that provide rural areas with access to gas service. Provisions of the legislation require that, among other things, requests for recovery include a seven-year project plan. Once the plan is approved by the IURC, 80 percent of such costs are eligible for current recovery using a periodic rate adjustment mechanism.

Recoverable costs include a return on the investment that reflects the current capital structure and associated costs, with the exception of the rate of return on equity, which remains fixed at the rate determined in the Company's last rate case. Recoverable costs also include recovery of depreciation and other operating expenses. The remaining 20 percent of project costs are deferred and recovered in the utility’s next general rate case, which must be filed before the expiration of the seven-year plan. The adjustment mechanism is capped at an annual increase in retail revenues of no more than two percent.

Ohio House Bill 95 (House Bill 95) permits a natural gas utility to apply for recovery of much of its capital expenditure program. This legislation also allows for the deferral of costs, such as depreciation, property taxes, and debt-related post-in-service carrying costs until recovery is approved by the PUCO.

Indiana Recovery and Deferral Mechanisms

The Company's Indiana natural gas utilities received Orders in 2008 and 2007 associated with the most recent base rate cases. These Orders authorized the deferral of financial impacts associated with bare steel and cast iron replacement activities. The Orders provide for the deferral of depreciation and post-in-service carrying costs on qualifying projects totaling $20 million annually at Indiana Gas and $3 million annually at SIGECO. The debt-related post-in-service carrying costs are currently recognized in the Consolidated Statements of Income. The recording of post-in-service carrying costs and depreciation deferral is limited by individual qualifying project to three years after being placed into service at SIGECO and four years after being placed into service at Indiana Gas. At December 31, 2016 and December 31, 2015, the Company has regulatory assets totaling $21.9 million and $19.9 million, respectively, associated with the deferral of depreciation and debt-related post-in-service carrying cost activities. Beginning in 2014, all bare steel and cast iron replacement activities are now part of the Company’s seven-year capital investment plan discussed below.

Requests for Recovery under Indiana Regulatory Mechanisms

In August 2014, the IURC issued an Order approving the Company’s seven-year capital infrastructure replacement and improvement plan (the Plan), beginning in 2014, and the proposed accounting authority and recovery. Compliance projects and other infrastructure improvement projects were approved pursuant to Senate Bill 251 and 560, respectively. As provided in the two laws, the Order approved semi-annual filings for rate recovery of 100 percent of the costs, inclusive of return, related to these capital investments and operating expenses, with 80 percent of the costs, including a return, recovered currently via an approved tracking mechanism and 20 percent of the costs deferred and recovered in the Company’s next base rate proceeding. In addition, the Order established guidelines to annually update the seven-year capital investment plan. Finally, the Order approved the Company’s proposal to recover eligible costs assigned to the residential customer class via a fixed monthly charge per residential customer.

In March 2016, the IURC issued an Order re-approving approximately $890 million of the Company’s gas infrastructure modernization projects requested in the third update of the Plan, and approving the inclusion in rates of actual investments made through June 30, 2015. While most of the proposed capital spend has been approved as proposed, approximately $80 million of projects were not approved for recovery through the mechanisms pursuant to these filings. Specifically, Vectren proposed to add a new project to its Plan pursuant to Senate Bill 560 totaling approximately $65 million. The project, which consists of a 20-mile transmission line and other related investments required to support industrial customer growth and ongoing system reliability in the Lafayette, Indiana area, as well as allows the Company to further diversify its gas supply portfolio via access to shale gas in the Marcellus and Utica reserves, was excluded for recovery under the Plan. The IURC stated because the project was not in the original plan filed in 2013, it does not qualify for cost recovery under this law. In the Order, the IURC did pre-approve the project for rate base inclusion upon the filing of the next base rate case. The Company believes such plan updates should be expected to accommodate new projects that emerge during the term of the plan as ongoing risk assessments determine new projects are required. The Company filed an appeal of the March 2016 Order on April 29, 2016 to challenge the IURC's finding which limits the scope of the Plan updates. The outcome of the appeal is expected in the first half of 2017.

Subsequent to the March 2016 Order, the Company has received two additional Orders approving plan investments. On June 29, 2016, the IURC issued an Order approving the inclusion in rates of investments made from July 2015 to December 2015. On January 25, 2017 the IURC issued an Order (January 2017 Order) approving the inclusion in rates of investments made from January 2016 to June 2016. Through the January 2017 Order, approximately $338 million of the approved capital investment plan has been incurred and included for recovery. The January 2017 Order also approved the Company's plan update, which is now $950 million through 2020. The plan increase of $60 million is due to additional investment related to pipeline safety and compliance requirements under Senate Bill 251.

At December 31, 2016 and December 31, 2015, the Company has regulatory assets related to the Plan totaling $51.1 million and $28.6 million, respectively.

Ohio Recovery and Deferral Mechanisms
The PUCO Order approving the Company's 2009 base rate case in the Ohio service territory authorized a distribution replacement rider (DRR). The DRR's primary purpose is recovery of investments in utility plant and related operating expenses associated with replacing bare steel and cast iron pipelines, as well as certain other infrastructure investments. This rider is updated annually for qualifying capital expenditures and allows for a return on those capital expenditures based on the rate of return approved in the 2009 base rate case. In addition, deferral of depreciation and the ability to accrue debt-related post-in-service carrying costs is also allowed until the related capital expenditures are included in the DRR. The Order also initially established a prospective bill impact evaluation on the annual deferrals. On February 19, 2014, the PUCO issued an Order approving a Stipulation entered into by the PUCO Staff and the Company which provided for the extension of the DRR for the recovery of costs incurred through 2017 and expanded the types of investment covered by the DRR to include recovery of certain other infrastructure investments. The Order limits the resulting DRR fixed charge per month for residential and small general service customers to specific graduated levels through 2017. The capital expenditure plan is subject to the graduated caps on the fixed DRR monthly charge applicable to residential and small general service customers approved in the Order. In the event the Company exceeds these caps, amounts in excess can be deferred for future recovery. The remaining capital expenditure plan to be included for recovery in future DRR filings is estimated to be approximately $100 million to $120 million. The Order also approved the Company's commitment that the DRR can only be further extended as part of a base rate case. In total, the Company has made capital investments on projects that are now in-service under the DRR totaling $259.6 million as of December 31, 2016, of which $204 million has been approved for recovery under the DRR through December 31, 2015. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $24.4 million and $18.2 million at December 31, 2016 and December 31, 2015, respectively. In August 2016, the Company received approval to adjust the DRR rates, effective September 1, 2016, for recovery of investments placed in-service through December 31, 2015.

The PUCO has also issued Orders approving the Company's filings under Ohio House Bill 95. These Orders approve deferral of the Company’s Ohio capital expenditure program for items not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. Ohio House Bill 95 Orders also established a prospective bill impact evaluation on the cumulative deferrals, limiting the total deferrals at a level which would equal $1.50 per residential and small general service customer per month. At December 31, 2016 and December 31, 2015, the Company has regulatory assets totaling $41.9 million and $24.1 million, respectively, associated with the deferral of depreciation, post-in-service carrying costs, and property taxes. As of December 31, 2016, the Company's deferrals have not reached this bill impact cap. On May 2, 2016, the Company submitted its most recent annual report required under its House Bill 95 Order. This report covers the Company's capital expenditure program through calendar year 2016.

Given the extension of the DRR through 2017, as discussed above, and the continued ability to defer other capital expenses under House Bill 95, it is anticipated that the Company will file a general rate case for the inclusion in rate base of the above costs in early 2018.

Pipeline and Hazardous Materials Safety Administration (PHMSA)
In March of 2016, PHMSA published a notice of proposed rulemaking (NPRM) on the safety of gas transmission and gathering lines. The proposed rule addresses many of the remaining requirements of the 2011 Pipeline Safety Act, with a particular focus on extending integrity management rules to address a much larger portion of the natural gas infrastructure and adds requirements to address broader threats to the integrity of a pipeline system. The Company is evaluating the impact that these proposed rules will have on its integrity management programs and transmission and distribution systems. In December of 2016, PHMSA issued final rules related to integrity management for storage operations. These rules are being evaluated with efforts underway to implement the new requirements. Further, the Company reviewed the Underground Natural Gas Storage Safety Recommendations from a joint Department of Energy and PHMSA led interagency task force. PHMSA has final rules pending that address requirements related to

plastic pipe, operator qualifications, valve installation and rupture detection, and incident notification. Each of these rules is expected to be published by PHMSA in 2017. Additionally, PHMSA has recently finalized a rule on excess flow valves, which will go into effect in April 2017. These rules will increase the potential for capital expenditures and increase operating and maintenance expenses. The Company believes that the cost to comply with these new rules should be recoverable using the regulatory recovery mechanisms referenced above.

19. Electric Rate and Regulatory Matters

Regulatory Treatment of Investments in Electric Infrastructure

On February 23, 2017, the Company filed for authority to recover costs related to its electric system modernization plan, using the mechanism allowed under Senate Bill 560. The electric system modernization plan includes investments to upgrade portions of the Company's network of substations, transmission and distribution systems, to enhance reliability and allow the grid to accept advanced technology to improve the information and service provided to customers. The filing requests the recovery of associated capital expenditures estimated to be approximately $500 million over the seven-year period beginning in 2017. A procedural schedule has not been set in this proceeding, but under Senate Bill 560, an order is expected within 210 days of filing.

Renewable Generation Resources

On February 22, 2017, the Company also filed for authority to recover costs related to the construction of three solar projects, using the mechanism allowed under Senate Bill 29, which allows for timely recovery of costs and expenses incurred during the construction and operation of clean energy projects. These investments, presented as part of the Company's Integrated Resource Plan (IRP) submitted in December 2016, allow the Company to add an initial 4 MW of universal solar generation, rooftop solar generation, and 1 MW of battery storage resources to its portfolio. See more information on the IRP below in Environmental and Sustainability Matters. The cost of the projects is estimated to be approximately $15 million. A procedural schedule has not been set in this proceeding, however an order is expected later in 2017.

SIGECO Electric Environmental Compliance Filing

In January 2015, the IURC issued an Order approving the Company's request for approval of capital investments in its coal-fired generation units to comply with new EPA mandates related to mercury and air toxic standards (MATS) effective in 2015 and to address an outstanding Notice of Violation (NOV) related to sulfur trioxide emissions from the EPA. As of December 31, 2016, $30 million has been spent on equipment to control mercury in both air and water emissions, and $40 million to address the issues raised in the NOV. The Order approved the Company's request for deferred accounting treatment, as supported by provisions under Indiana Senate Bill 29 and Senate Bill 251. The accounting treatment includes the deferral of depreciation and property tax expense related to these investments, accrual of post-in-service carrying costs, and deferral of incremental operating expenses related to compliance with these standards. The initial phase of the projects went into service in 2014, with the remaining investment going into service in 2016. As of December 31, 2016, the Company has approximately $6.9 million deferred related to depreciation and operating expense, and $2.8 million deferred related to post-in-service carrying costs.

In June 2015, Joint Appellants' Citizens Action Coalition of Indiana, Inc., Sierra Club, Inc., and Valley Watch, Inc. (the appellants) challenged the IURC's January Order. On October 29, 2015, the Indiana Court of Appeals issued an opinion that affirmed the IURC's findings with regard to equipment required to comply with MATS and certain national pollutant discharge elimination system rules (approximately $30 million) but remanded the case to the IURC to determine whether a certificate of public convenience and necessity (CPCN) should be issued for the equipment required by the NOV (approximately $40 million). On June 22, 2016, the IURC issued an Order granting Vectren a CPCN for the NOV-required equipment. On July 21, 2016, the appellants initiated an appeal of the IURC's June 22, 2016 Order challenging the findings made by the IURC. On February 14, 2017, the Court affirmed the IURC's June 22, 2016 Order.

SIGECO Electric Demand Side Management (DSM) Program Filing

On August 31, 2011, the IURC issued an Order approving an initial three-year DSM plan in the SIGECO electric service territory that complied with the IURC's energy saving targets. Consistent with the Company's proposal, the Order approved, among other items, the following: 1) recovery of costs associated with implementing the DSM Plan; 2) the recovery of a performance incentive mechanism based on measured savings related to certain DSM programs;

and 3) lost margin recovery associated with the implementation of DSM programs for large customers. On June 20, 2012, the IURC issued an Order approving a small customer lost margin recovery mechanism, inclusive of all previous deferrals. For the twelve months ended December 31, 2016, 2015, and 2014, the Company recognized electric utility revenue of $11.1 million, $10.1 million and $8.7 million, respectively, associated with this approved lost margin recovery mechanism.

On March 28, 2014, Indiana Senate Bill 340 was signed into law. The legislation allows for industrial customers to opt out of participating in energy efficiency programs and as a result of this legislation, most of the Company’s eligible industrial customers have since opted out of participation in the applicable energy efficiency programs.

Indiana Senate Bill 412 (Senate Bill 412) requires electricity suppliers to submit energy efficiency plans to the IURC at least once every three years. Senate Bill 412 also permits the recovery of all program costs, including lost revenues and financial incentives associated with those plans and approved by the IURC. The Company made its first filing pursuant to this bill in June 2015, which proposed energy efficiency programs for calendar years 2016 and 2017. On March 23, 2016, the IURC issued an Order approving the Company’s 2016-2017 energy efficiency programs. The Order provides for cost recovery of program and administrative expenses and includes performance incentives for reaching energy savings goals. The Order also included a lost margin recovery mechanism that now limits that recovery related to new programs to the shorter of four years or the life of the installed energy efficiency measure. Prior electric energy efficiency orders did not limit lost margin recovery in this manner. This ruling follows other recent IURC decisions implementing the same lost margin recovery limitation with respect to other electric utilities in Indiana. The Company is committed to continuing to promote and drive participation in its energy efficiency programs and has therefore appealed this lost margin recovery restriction. The Company expects a decision on its appeal in the first half of 2017.

FERC Return on Equity (ROE) Complaints

On November 12, 2013, certain parties representing a group of industrial customers filed a joint complaint with the FERC under Section 206 of the Federal Power Act against the MISO and various MISO transmission owners, including SIGECO (first complaint case). The joint parties sought to reduce the 12.38 percent ROE used in the MISO transmission owners’ rates, including SIGECO’s formula transmission rates, to 9.15 percent covering the refund period from November 12, 2013 through February 11, 2015 (first refund period). On September 28, 2016, the FERC issued a final order authorizing a 10.32 percent base ROE for the first refund period and prospectively through the date of the order in a second complaint case as detailed below.

A second customer complaint case was filed on February 11, 2015 covering the refund period from February 12, 2015 through May 11, 2016 (second refund period). An initial decision from the FERC administrative law judge on June 30, 2016, authorized a base ROE of 9.70 percent for the second refund period. The FERC is expected to rule on the proposed order in the second complaint case in 2017, which will authorize a base ROE for this period and prospectively from the date of the order.

Separately, on January 6, 2015, the FERC approved a MISO transmission owner joint request for an adder to the approved ROE. Under FERC regulations, transmission owners that are part of a Regional Transmission Organization (RTO) such as the MISO are authorized to earn an incentive of 50 basis points above the FERC approved ROE. The FERC deferred the implementation of this adder until the pending complaint is resolved. The adder will be applied retroactively from January 6, 2015 through May 11, 2016 and prospectively from the September 28, 2016 order in the first complaint case.

The Company has reflected these results in its financial statements. As of December 31, 2016, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $136.8 million at December 31, 2016.

20. Environmental and Sustainability Matters

The Company initiated its corporate sustainability program in 2012 with the publication of its initial corporate sustainability report. Since that time the Company continues to develop strategies that focus on those environmental, social and governance (ESG) factors that contribute to the long-term growth of the Company’s sustainable business model. As detailed further below and in the upcoming corporate sustainability report for 2016, the Company continues to set out its plans, among other things, to upgrade and diversify its generation portfolio. The Company's sustainability policies and efforts, and in particular its policies and procedures designed to ensure compliance with applicable laws and regulations, are directly overseen by the Board's Corporate Responsibility and Sustainability Committee, as well as vetted with the full Board of Directors. Further discussion of key goals, strategies, and governance practices can be found in the Company's latest sustainability report at www.vectren.com/sustainability, which received core level certification from the Global Reporting Initiative.

The Company's utility operations and properties are subject to extensive environmental regulation pursuant to a variety of federal, state, and municipal laws and regulations. These environmental regulations impose, among other things, restrictions, liabilities, and obligations in connection with the storage, transportation, treatment, and disposal of hazardous substances and limit airborne emissions from electric generating facilities including particulate matter, sulfur dioxide (SO2), nitrogen oxide (NOx), and mercury, among others. Environmental legislation and regulation also requires that facilities, sites, and other properties associated with the Company's operations be operated, maintained, abandoned, and reclaimed to the satisfaction of applicable regulatory authorities. The Company's current costs to comply with these laws and regulations are significant to its results of operations and financial condition. Similar to the costs associated with federal mandates in the Pipeline Safety Law, Senate Bill 251 is also applicable to federal environmental mandates impacting SIGECO's electric operations.

Integrated Resource Planning Process
As required by the state of Indiana, the Company completed its 2016 Integrated Resource Plan (IRP) and submitted to the IURC for review on December 16, 2016. The Company anticipates the IURC will, likely in the summer of 2017, release a director’s report to the other state utilities that filed their IRPs in 2016. The state requires each electric utility to perform and submit an IRP that uses economic modeling to consider the costs and risks associated with available resource options to provide reliable electric service for the next twenty year period. During 2016, the Company held three public stakeholder meetings to gather input and feedback as well as communicate results of the IRP process as it progressed. In developing its IRP, the Company considered both the cost to continue operating its existing generation units in a manner that complies with current and anticipated future environmental requirements, as well as various resource alternatives, such as the use of energy efficiency programs and renewable resources as part of its overall generation portfolio.

Currently, the Company operates approximately 1,000 MW of coal-fired generation, 245 MW of natural gas peaking units, and 3 MW via a landfill-gas-to-electricity facility. The Company also has 80 MW of wind power through two long-term power purchase agreements and 32 MW of coal generation through its ownership in OVEC. The Company’s 2016 IRP preferred portfolio illustrates a future less reliant on coal. The twenty year plan reflects the retirement of a portion of the Company’s current coal-fired fleet, transitions a significant portion of generation to natural gas and includes new renewable energy sources, specifically universal solar. The detailed plan would introduce approximately 54 MW of universal solar installed by 2019. The plan suggests the Company will exit its joint operations of Warrick Unit 4, a 300 MW unit shared with Alcoa, by 2020. The Company would complete upgrades to its existing coal-fired Culley Unit 3, a 270-megawatt unit, to comply with federal water regulations specific to the Effluent Limitations Guidelines (ELG) around 2023 in order to keep the unit in operation. In 2024, the plan points to the retirement of coal-fired AB Brown plant Units 1 & 2 along with Culley Unit 2, collectively representing 580 MW. This generation would be replaced by a newly constructed combined cycle natural gas plant, with the capability of producing approximately 890 MW by 2024. In addition, the Company intends to continue to offer energy efficiency programs annually.

The Company’s plan considered a broad range of potential resources and variables and is focused on ensuring it offers a reliable, reasonably priced generation portfolio as well as a balanced energy mix. The Company plans to finalize this generation portfolio transition plan and submit a regulatory filing, including construction timelines and costs of new generation resources, to the IURC in late 2017 to begin the generation transition process. The Company believes that all compliance costs, including cost of new generation as well as the cost of retiring generation, would be considered a federally mandated cost of providing electricity and therefore should be recoverable either from customers through Senate Bill 251 as referenced above, Senate Bill 29 used by the Company to recover its initial pollution control investments, or through other forms of rate recovery.

Coal Ash Waste Disposal, Ash Ponds and Water

Coal Combustion Residuals Rule

In December 2014, the EPA released its final Coal Combustion Residuals (CCR) rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). On April 17, 2015, the final rule was published in the Federal Register. The final rule allows beneficial reuse of ash and the majority of the ash generated by the Company’s generating plants will continue to be reused. As it relates to the CCR rule, legislation was passed in December 2016 by Congress that would provide for enforcement of the federal program by states rather than through citizen suits. Additionally, the CCR rule is currently being challenged by multiple parties in judicial review proceedings.

Under the final CCR rule, the Company is required to complete a series of integrity assessments, including seismic modeling given the Company’s facilities are located within two seismic zones, and groundwater monitoring studies to determine the remaining service life of the ponds and whether a pond must be retrofitted with liners or closed in place, with bottom ash handling conversions completed. In late 2015, using general utility industry data, the Company prepared cost estimates for the retirement of the ash ponds at the end of their useful lives, based on its interpretation of the closure alternatives contemplated in the final rule. The resulting estimates ranged from approximately $35 million to $80 million. These estimates contemplated final capping and monitoring costs of the ponds at both F.B. Culley and A.B. Brown generating stations. These rules are not applicable to the Company's Warrick generating unit, as this unit has historically been part of a larger generating station that predominantly serves an adjacent industrial facility.

Throughout 2016, the Company has continued to refine site specific estimates and now estimates the costs to be in the range of $45 million to $100 million. Significant factors impacting the resulting cost estimates include the closure time frame and the method of closure. Current estimates contemplate additional beneficial reuse of the ash, as well as implications of the Company’s preferred IRP. Ongoing analysis, the continued refinement of assumptions, or the inability to beneficially reuse the ash may result in estimated costs in excess of the current range.

As of December 31, 2016, the Company had recorded an approximate $40 million asset retirement obligation (ARO). The recorded ARO reflects the present value of the approximate $45 million in estimated costs in the range above. These assumptions and estimations are subject to change in the future and could materially impact the amount of the estimated ARO.

In order to maintain current operations of the ponds, the Company has spent approximately $17 million on the reinforcement of the ash pond dams and other operational changes in 2016 to meet the more stringent 2,500 year seismic event structural and safety standard in the CCR rule.

Effluent Limitation Guidelines (ELGs)
Under the Clean Water Act, the EPA sets technology-based guidelines for water discharges from new and existing electric generation facilities. On September 30, 2015, the EPA released final revisions to the existing steam electric ELGs setting stringent technology-based water discharge limits for the electric power industry. The EPA focused this rulemaking on wastewater generated primarily by pollution control equipment necessitated by the comprehensive air regulations, specifically setting strict water discharge limits for arsenic, mercury and selenium for scrubber waste waters. The ELGs will be implemented when existing water discharge permits for the plants are renewed, with compliance activities expected to commence where operations continue, within the 2018-2023 time frame. The ELGs work in tandem with the aforementioned CCR requirements, effectively prohibiting the use of less costly lined sediment basin options for disposal of coal combustion residuals, and virtually mandate conversions to dry bottom ash handling.

The current wastewater discharge permit for the A.B. Brown power plant had an expiration date of October 2016 and, for the F.B. Culley plant, a date of December 2016. The Company is continuing ongoing discussions with the state environmental agency during the first half of 2017 and anticipates final permits will be issued in the second quarter of 2017. During the renewal process, existing permits remain in place. As part of the permit renewals, the Company requested alternate compliance dates for ELGs. Compliance with the ELGs will not be required prior to November 2018, but no later than December 31, 2023. For plants identified in the Company’s preferred IRP to be retired prior to December 31, 2023, the Company has requested those plants would not require new treatment technology. For the F.B. Culley plant, the Company has proposed a 2020 compliance date for dry bottom ash and 2023 compliance date for flue gas desulfurization wastewater. The Company anticipates acceptance of the proposed schedule.

Cooling Water Intake Structures

Section 316(b) of the Clean Water Act requires generating facilities use the “best technology available” (BTA) to minimize adverse environmental impacts on a body of water. More specifically, Section 316(b) is concerned with impingement and entrainment of aquatic species in once-through cooling water intake structures used at electric generating facilities. A final rule was issued by the EPA on May 19, 2014. The final rule does not mandate cooling water tower retrofits but requires a state level case-by-case assessment of BTA for each facility. The final rule lists seven presumptive technologies which would qualify as BTA. These technologies range from intake screen modifications to cooling water tower retrofits. Ecological and technology assessment studies must be completed prior to determining BTA for the Company's facilities. The Company is currently undertaking the required ecological studies and anticipates timely compliance in 2021-2022. To comply, the Company believes capital investments will likely be in the range of $4 million to $8 million.

Air Quality

Mercury and Air Toxics (MATS) Rule

On December 21, 2011, the EPA finalized the utility MATS rule. The MATS rule sets emission limits for hazardous air pollutants for existing and new coal-fired power plants and identifies the following broad categories of hazardous air pollutants: mercury, non-mercury hazardous air pollutants (primarily arsenic, chromium, cobalt, and selenium), and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride). The rule imposes mercury emission limits for two sub-categories of coal and proposed surrogate limits for non-mercury and acid gas hazardous air pollutants.

In July 2014, a coalition of twenty-one states, including Indiana, filed a petition with the U.S. Supreme Court seeking review of the decision of the appellate court that found the EPA appropriately based its decision to list coal and oil fired generation units as a source of the pollutants at issue solely on those pollutants' impact on public health. On June 29, 2015, the U.S. Supreme Court reversed the appellate court decision on the basis of the EPA's failure to consider costs before determining whether it was appropriate and necessary to regulate steam electric generating units under Section 112 of the Clean Air Act. The Court did not vacate the rule, but remanded the MATS rule to the appellate court for further proceedings consistent with the opinion. In April 2016, in response to the Court's remand, the EPA affirmed its earlier conclusion in a Supplemental Finding, and in June 2016, a coalition of states and other stakeholders filed challenges to the Supplemental Finding. MATS compliance was required to commence April 16, 2015, and the Company continues to operate in full compliance with the MATS rule.

Notice of Violation for A.B. Brown Power Plant

The Company received a NOV from the EPA in November 2011 pertaining to its A.B. Brown generating station. The NOV asserts when the facility was equipped with Selective Catalytic Reduction (SCR) systems, the correct permits were not obtained or the best available control technology to control incidental sulfuric acid mist was not installed. While the Company did not agree with the notice, it reached a final settlement with the EPA to resolve the NOV in December 2015.

As noted previously, on January 28, 2015, the IURC issued an Order approving the Company's request for approval of capital investments on its coal-fired generation units to comply with new EPA mandates related to MATS effective in 2015 and to address the outstanding NOV. The total investment was $70 million of which $30 million was spent to control mercury in both air and water emissions, and the remaining investment was made to address the issues raised in the NOV.

In June 2015, Joint Appellants' Citizens Action Coalition of Indiana, Inc., Sierra Club, Inc., and Valley Watch, Inc. (the appellants) challenged the IURC's January Order. On October 29, 2015, the Indiana Court of Appeals issued an opinion that affirmed the IURC's findings with regard to equipment required to comply with MATS and certain national pollutant discharge elimination system rules (approximately $30 million) but remanded the case to the IURC to determine whether a certificate of public convenience and necessity (CPCN) should be issued for the equipment required by the NOV (approximately $40 million). On June 22, 2016, the IURC issued an Order granting Vectren a CPCN for the NOV-required equipment. On July 21, 2016, the appellants initiated an appeal of the IURC's June 22, 2016 Order challenging the findings made by the IURC. On February 14, 2017, the Court affirmed the IURC's June 22, 2016 Order.

Ozone NAAQS
On November 26, 2014, the EPA proposed to tighten the current National Ambient Air Quality Standard (NAAQS) for ozone from the current standard of 75 parts per billion (ppb) to a level with the range of 65 to 70 ppb. On October 1, 2015, the EPA finalized a new NAAQS for ozone at the high end of the range, or 70 ppb. On September 16, 2016, Indiana submitted its initial determination to the EPA recommending that counties in southwest Indiana, specifically Vanderburgh, Posey and Warrick, be declared in attainment of the new more stringent ozone standard based upon air monitoring data from 2014-2016. The EPA is expected to make final determinations as to whether a region is in attainment for the new NAAQS in 2017. While it is possible that counties in southwest Indiana could be declared in non-attainment with the new standard, and thus could have an effect on future economic development activities in the Company's service territory, the Company does not anticipate any significant compliance cost impacts from the determination given its previous investment in SCR technology for NOx control on its units. In September 2016, the EPA finalized a supplement to the Cross State Air Pollution Rule (CSAPR) that requires further NOx reductions during the ozone season (May - September). The Company is positioned to comply with these NOx reduction requirements through its current investment in SCR technology.

One Hour SO2 NAAQS
On February 16, 2016, the EPA notified states of the commencement of a 120 day consultation period between the state and the EPA with respect to the EPA's recommendations for new non-attainment designations for the 2010 One Hour SO2 NAAQS. Identified on the list was Posey County, Indiana, where the Company's A.B. Brown Generating Station is located. While the Company is in compliance with all applicable SO2 limits in its permits, the Company reached an agreement with the state of Indiana on voluntary measures that the Company was able to implement without significant incremental costs to ensure that Posey County remains in attainment with the 2010 One Hour SO2 NAAQS. The Company's coal-fired generating fleet is 100 percent scrubbed for SO2 and 90 percent controlled for NOx.

Climate Change

On August 3, 2015, the EPA released its final CPP rule which requires a 32 percent reduction in carbon emissions from 2005 levels. This results in a final emission rate goal for Indiana of 1,242 lb CO2/MWh to be achieved by 2030. The new rule gives states the option of seeking a two-year extension from the initial deadline of September 2016 to submit a final state implementation plan (SIP). Under the CPP, states have the flexibility to include energy efficiency and other measures should they choose to implement a SIP as provided in the final rule. While states are given an interim goal (1,451 lb CO2/MWh for Indiana), the final rule gives states the flexibility to shape their own emissions reduction over the 2022-2029 time period. The final rule was published in the Federal Register on October 23, 2015 and that action was immediately followed by litigation initiated by Indiana and 23 other states as a coalition challenging the rule. In January of 2016, the reviewing court denied the states' and other parties requests to stay the implementation of the CPP pending completion of judicial review. On January 26, 2016, 29 states and state agencies, including the 24 state coalition referenced above, filed a request for immediate stay with the U.S. Supreme Court. On February 9, 2016, the U.S. Supreme Court granted a stay to delay the regulation while being challenged in court. Extensive oral argument was held in September. The stay will remain in place while the lower court concludes its review. Among other things, the stay delays the requirement to submit a final SIP by the original September 2016 deadline and could extend implementation to 2024.

In the event a state does not submit a SIP, the EPA also released a proposed federal implementation plan (FIP), which would be imposed on those states without an approved SIP. The proposed FIP would apply an emission rate requirement directly on generating units. Under the proposed FIP, the CO2 emission rate limit for coal-fired units would start at 1,671 lbs CO2/MWh in 2022 and decrease to a final emission rate cap of 1,305 lbs CO2/MWh by 2030. While the FIP emission rate cap appears to be slightly less stringent than the state reduction goal for Indiana, the cap would apply directly to generating units and these units would not have the benefit of averaging emission rates with rates from zero-carbon sources as would be available in a SIP. Purchases of emission credits from zero-carbon sources can be made for compliance. The FIP will be subject to extensive public comments prior to finalization. Whether Indiana will file a SIP has yet to be determined. Pending that determination, the electric utilities in Indiana will continue to encourage the state's designated agency to analyze various compliance options and the possible integration into a state plan submittal.

At the time of release of the CPP, Indiana was the 5th largest carbon emitter in the nation in tons of CO_2 produced from electric generation. The Company’s share of total tons of CO_2 generated by Indiana's electric utilities has historically been less than 6 percent. Since 2005 through 2015, the Company has achieved a reduction in emissions of CO_2 of 31 percent (on a tonnage basis) through the retirement of F.B. Culley Unit 1, expiration of municipal wholesale power contracts, electric conservation, the addition of renewable generation, and the installation of more efficient dense pack turbine technology. Since emissions are further impacted by coal burn reductions and energy efficiency programs, the Company's emissions of CO_2 can vary year to year. With respect to renewable generation, in 2008 and 2009, the Company executed long-term purchase power commitments for a total of 80 MW of wind energy. The Company currently has approximately 4 percent of its electricity being provided by energy sources other than coal and natural gas, due to the long-term wind contracts and landfill gas investment. With respect to CO_2 emission rate, since 2005 through 2015, the Company has lowered its CO_2 emission rate (as measured in lbs CO_2/MWh) from 1,967 lbs CO_2/MWh to 1,922 lbs CO_2/MWh, for a reduction of 3 percent. The Company’s CO_2 emission rate of 1,922 lbs CO_2/MWh is basically the same as Indiana's average CO_2 emission rate of 1,923 lbs CO_2/MWh. The Company plans to consider these reductions in CO_2 emissions and renewable generation in future discussions with the state to develop a possible state implementation plan.

Impact of Legislative Actions & Other Initiatives is Unknown
At this time, compliance costs and other effects associated with reductions in GHG emissions or obtaining renewable energy sources remain uncertain. The Company has gathered preliminary estimates of the costs to control GHG emissions. A preliminary investigation demonstrated costs to comply would be significant, first with regard to operating expenses and later for capital expenditures as technology becomes available to control GHG emissions. However, these compliance cost estimates were based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. The Company is undertaking a detailed review of the requirements of the CPP and the proposed FIP and a review of potential compliance options. The Company will also continue to remain engaged with the Indiana legislators and regulators to assess the final rule and to develop a plan that is the least cost to its customers.

In addition to the federal programs, the United States and 194 other countries agreed by consensus to limit GHG emissions beginning after 2020 in the 2015 United Nations Framework Convention on Climate Change Paris Agreement. The United States has proposed a 26-28 percent GHG emission reduction from 2005 levels by 2025. As previously noted, since 2005 through 2015, the Company has achieved reduced emissions of CO_2 by 31 percent (on a tonnage basis). While the legislative outcome of the CPP rules remains uncertain, the Company will continue to monitor regulatory activity regarding GHG emission standards that may affect its electric generating units.

Manufactured Gas Plants
In the past, the Company operated facilities to manufacture natural gas. Given the availability of natural gas transported by pipelines, these facilities have not been operated for many years. Under current environmental laws and regulations, those that owned or operated these facilities may now be required to take remedial action if certain contaminants are found above the regulatory thresholds.

In the Indiana Gas service territory, the existence, location, and certain general characteristics of 26 gas manufacturing and storage sites have been identified for which the Company may have some remedial responsibility. A remedial investigation/ feasibility study (RI/FS) was completed at one of the sites under an agreed upon order between Indiana Gas and the IDEM, and a Record of Decision was issued by the IDEM in January 2000. The remaining sites have been submitted to the IDEM's Voluntary Remediation Program (VRP). The Company has identified its involvement in five manufactured gas plant sites in SIGECO’s service territory, all of which are currently enrolled in the IDEM’s VRP. The Company is currently conducting some level of remedial activities, including groundwater monitoring at certain sites.

The Company has accrued the estimated costs for further investigation, remediation, groundwater monitoring, and related costs for the sites. While the total costs that may be incurred in connection with addressing these sites cannot be determined at this time, the Company has recorded cumulative costs that it has incurred or reasonably expects to incur totaling approximately $44.2 million ($23.9 million at Indiana Gas and $20.3 million at SIGECO). The estimated accrued costs are limited to the Company's share of the remediation efforts and are therefore net of exposures of other potentially responsible parties (PRP).

With respect to insurance coverage, Indiana Gas has received approximately $20.8 million from all known insurance carriers under insurance policies in effect when these plants were in operation. Likewise, SIGECO has settlement agreements with all known insurance carriers and has received approximately $15.2 million of the expected $15.8 million in insurance recoveries.

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company’s utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of December 31, 2016 and December 31, 2015, approximately $2.9 million and $3.3 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

21. Fair Value Measurements

The carrying values and estimated fair values using primarily Level 2 assumptions of the Company's other financial instruments follow:

	At December 31,			
	2016		2015	
(In millions)	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	$1,714.0	$1,835.8	$1,785.9	$1,899.6
Short-term borrowings & notes payable	194.4	194.4	14.5	14.5
Cash & cash equivalents	68.6	68.6	74.7	74.7
Restricted cash	0.9	0.9	5.9	5.9

For the balance sheets dates presented in these financial statements, the Company had no material assets or liabilities marked to fair value.

Certain methods and assumptions must be used to estimate the fair value of financial instruments. The fair value of the Company's long-term debt was estimated based on the quoted market prices for the same or similar issues or on the current rates offered to the Company for instruments with similar characteristics. Because of the maturity dates and variable interest rates of short-term borrowings and cash & cash equivalents, those carrying amounts approximate fair value. Because of the inherent difficulty of estimating interest rate and other market risks, the methods used to estimate fair value may not always be indicative of actual realizable value, and different methodologies could produce different fair value estimates at the reporting date.

Under current regulatory treatment, call premiums on reacquisition of utility-related long-term debt are generally recovered in customer rates over the life of the refunding issue. Accordingly, any reacquisition of this debt would not be expected to have a material effect on the Company's results of operations.

Because of the nature of certain other investments and lack of a readily available market, it is not practical to estimate the fair value of these financial instruments at specific dates without considerable effort and cost. At December 31, 2016 and 2015, the fair value for these financial instruments was not estimated. The carrying value of these investments at December 31, 2016 and 2015 was approximately $16.1 million.

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22. Segment Reporting

The Company segregates its operations into three groups: 1) Utility Group, 2) Nonutility Group, and 3) Corporate and Other.

The Utility Group is comprised of Vectren Utility Holdings, Inc.’s operations, which consist of the Company’s regulated operations and other operations that provide information technology and other support services to those regulated operations. The Company segregates its regulated operations between a Gas Utility Services operating segment and an Electric Utility Services operating segment. The Gas Utility Services segment provides natural gas distribution and transportation services to nearly two-thirds of Indiana and to west central Ohio. The Electric Utility Services segment provides electric distribution services primarily to southwestern Indiana, and includes the Company’s power generating and wholesale power operations. Regulated operations supply natural gas and/or electricity to over one million customers. In total, the Utility Group is comprised of three operating segments: Gas Utility Services, Electric Utility Services, and Other operations.

During the periods presented, the Nonutility Group had the following operating segments: Infrastructure Services, Energy Services, Coal Mining, and Other Businesses. Energy Services, through the wholly owned subsidiary Energy Systems Group, LLC, provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects. The Infrastructure Services segment, through wholly owned subsidiaries Miller Pipeline, LLC and Minnesota Limited, LLC, provides underground pipeline construction and repair services for customers that include Vectren Utility Holdings' utilities. Fees incurred by Vectren Utility Holdings and its subsidiaries for these pipeline construction and repair services totaled $117.8 million in 2016, $109.5 million in 2015, and $94.0 million in 2014.

In its 2016 periodic reports, the 2014 results for the Coal Mining segment include the results of Vectren Fuels through August 29, 2014 when it exited the coal mining business through the sale of Vectren Fuels (see Note 6 for more details of this transaction).

Corporate and Other includes proceeds from life insurance policies offset by unallocated corporate expenses such as advertising and certain charitable contributions, among other activities, that benefit the Company’s other operating segments. Total assets in all periods presented reflect the retrospective impacts of the adoption in 2015 of ASU 2015-17, Balance Sheet Classification of Deferred Taxes and the retrospective impacts of the adoption in 2016 of ASU 2015-03, Presentation of Debt Issuance Costs. Net income is the measure of profitability used by management for all operations. Information related to the Company’s business segments is summarized as follows:

(In millions)	Year Ended December 31, 2016	2015	2014
Revenues			
Utility Group			
Gas Utility Services	$771.7	$792.6	$944.6
Electric Utility Services	605.8	601.6	624.8
Other Operations	42.2	40.7	38.3
Eliminations	(41.9)	(40.4)	(38.0)
Total Utility Group	1,377.8	1,394.5	1,569.7
Nonutility Group			
Infrastructure Services	813.3	843.3	779.0
Energy Services	260.0	199.9	129.8
Coal Mining	—	—	234.3
Total Nonutility Group	1,073.3	1,043.2	1,143.1
Eliminations, net of Corporate & Other Revenues	(2.8)	(3.0)	(101.1)
Consolidated Revenues	$2,448.3	$2,434.7	$2,611.7
Profitability Measures - Net Income			
Utility Group Net Income			
Gas Utility Services	$76.1	$64.4	$57.0
Electric Utility Services	84.7	82.6	79.7
Other Operations	12.8	13.9	11.7
Total Utility Group Net Income	173.6	160.9	148.4
Nonutility Group Net Income (Loss)			
Infrastructure Services	25.0	29.7	43.1
Energy Services	12.5	7.3	(3.2)
Coal Mining	—	—	(21.1)
Other Businesses	(0.6)	(0.7)	(0.8)
Total Nonutility Group Net Income	36.9	36.3	18.0
Corporate & Other Net Income	1.1	0.1	0.5
Consolidated Net Income	$211.6	$197.3	$166.9

	Year Ended December 31,		
(In millions)	2016	2015	2014
Amounts Included in Profitability Measures			
Depreciation & Amortization			
Utility Group			
Gas Utility Services	$108.1	$98.6	$93.3
Electric Utility Services	87.1	85.6	85.7
Other Operations	23.9	24.6	24.1
Total Utility Group	219.1	208.8	203.1
Nonutility Group			
Infrastructure Services	38.2	44.5	36.2
Energy Services	2.5	2.7	3.9
Coal Mining	—	—	29.9
Other Businesses	0.2	0.3	0.3
Total Nonutility Group	40.9	47.5	70.3
Consolidated Depreciation & Amortization	$260.0	$256.3	$273.4
Interest Expense			
Utility Group			
Gas Utility Services	$40.1	$35.8	$34.9
Electric Utility Services	27.0	27.8	29.0
Other Operations	2.6	2.7	2.7
Total Utility Group	69.7	66.3	66.6
Nonutility Group			
Infrastructure Services	12.8	16.0	11.1
Energy Services	1.9	1.2	1.3
Coal Mining	—	—	7.5
Other Businesses	0.9	1.2	0.9
Total Nonutility Group	15.6	18.4	20.8
Corporate & Other	0.2	(0.2)	(0.7)
Consolidated Interest Expense	$85.5	$84.5	$86.7
Income Taxes			
Utility Group			
Gas Utility Services	$47.1	$40.8	$35.7
Electric Utility Services	50.1	49.3	48.1
Other Operations	2.3	(2.0)	(0.6)
Total Utility Group	99.5	88.1	83.2
Nonutility Group			
Infrastructure Services	17.9	19.6	28.9
Energy Services	(3.5)	(7.7)	(7.8)
Coal Mining	—	—	(21.8)
Other Businesses	0.3	1.5	(0.3)
Total Nonutility Group	14.7	13.4	(1.0)
Corporate & Other	(1.3)	(1.8)	(1.1)
Consolidated Income Taxes	$112.9	$99.7	$81.1

	Year Ended December 31,		
(In millions)	2016	2015	2014
Capital Expenditures			
Utility Group			
Gas Utility Services	$358.5	$291.2	$245.9
Electric Utility Services	106.4	87.6	92.4
Other Operations	39.0	25.7	23.3
Non-cash costs & changes in accruals	(7.1)	(6.2)	(10.9)
Total Utility Group	496.8	398.3	350.7
Nonutility Group			
Infrastructure Services	43.2	78.1	54.1
Energy Services	1.8	0.5	1.6
Coal Mining	—	—	41.9
Other Businesses, net of eliminations	0.2	—	—
Total Nonutility Group	45.2	78.6	97.6
Consolidated Capital Expenditures	$542.0	$476.9	$448.3

	At December 31,		
(In millions)	2016	2015	2014
Assets			
Utility Group			
Gas Utility Services	$3,091.0	$2,706.9	$2,604.6
Electric Utility Services	1,788.4	1,778.3	1,656.2
Other Operations, net of eliminations	161.5	107.5	148.5
Total Utility Group	5,040.9	4,592.7	4,409.3
Nonutility Group			
Infrastructure Services	513.9	554.5	538.5
Energy Services	182.7	160.3	87.1
Other Businesses, net of eliminations and reclassifications	53.3	64.0	120.3
Total Nonutility Group	749.9	778.8	745.9
Corporate & Other	628.4	742.4	654.9
Eliminations	(618.5)	(713.9)	(672.3)
Consolidated Assets	$5,800.7	$5,400.0	$5,137.8

23. Additional Balance Sheet & Operational Information

Inventories consist of the following:

	At December 31,	
(In millions)	2016	2015
Gas in storage – at LIFO cost	$37.0	$40.5
Coal & oil for electric generation - at average cost	42.6	45.0
Materials & supplies	48.9	46.9
Other	1.4	1.3
Total inventories	$129.9	$133.7

Based on the average cost of gas purchased during December, the cost of replacing inventories carried at LIFO cost exceeded carrying value at December 31, 2016 by $1.0 million. Based on the average cost of gas purchased during December, the cost of replacing inventories carried at LIFO cost approximated carrying value at December 31, 2015.

Prepayments & other current assets consist of the following:

	At December 31,	
(In millions)	2016	2015
Prepaid gas delivery service	$26.4	$30.0
Prepaid taxes	8.2	25.3
Other prepayments & current assets	18.1	25.7
Total prepayments & other current assets	$52.7	$81.0

Investments in unconsolidated affiliates consist of the following:

	At December 31,	
(In millions)	2016	2015
ProLiance Holdings, LLC	$19.2	$19.7
Other nonutility partnerships & corporations	1.0	1.0
Other utility investments	0.2	0.2
Total investments in unconsolidated affiliates	$20.4	$20.9

Other utility & corporate investments consist of the following:

	At December 31,	
(In millions)	2016	2015
Cash surrender value of life insurance policies	$33.1	$30.1
Restricted cash & other investments	1.0	1.1
Total other utility & corporate investments	$34.1	$31.2

Goodwill by operating segment follows:

	At December 31,	
(In millions)	2016	2015
Utility Group		
Gas Utility Services	$205.0	$205.0
Nonutility Group		
Infrastructure Services	58.8	58.8
Energy Services	29.7	29.7
Consolidated goodwill	$293.5	$293.5

Accrued liabilities consist of the following:

	At December 31,	
(In millions)	2016	2015
Refunds to customers & customer deposits	$49.4	$51.4
Accrued taxes	46.5	39.9
Accrued interest	18.2	19.4
Deferred compensation & post-retirement benefits	6.6	7.2
Accrued salaries & other	87.0	65.7

Total accrued liabilities	$207.7	$183.6

Asset retirement obligations included in Deferred credits and other liabilities in the Consolidated Balance Sheets roll forward as follows:

(In millions)	2016	2015
Asset retirement obligation, January 1	$82.0	$55.0
Accretion	3.8	3.2
Liabilities incurred in current period	—	24.2
Changes in estimates, net of cash payments	20.9	(0.4)
Asset retirement obligation, December 31	106.7	82.0

Equity in earnings (losses) of unconsolidated affiliates consists of the following:

	Year Ended December 31,		
(In millions)	2016	2015	2014
ProLiance Holdings, LLC	$(0.5)	$(0.8)	$(0.3)
Other	0.3	0.2	0.8
Total equity in earnings (losses) of unconsolidated affiliates	$(0.2)	$(0.6)	$0.5

Other income (expense) – net consists of the following:

	Year Ended December 31,		
(In millions)	2016	2015	2014
AFUDC – borrowed funds	$20.3	$16.3	$11.4
AFUDC – equity funds	2.2	2.6	3.2
Nonutility plant capitalized interest	1.0	0.4	—
Interest income, net	1.3	1.3	1.1
Other nonutility investment impairment charges	—	(0.1)	(1.0)
All other income	3.9	(0.2)	5.0
Total other income (expense) – net	$28.7	$20.3	$19.7

Supplemental Cash Flow Information:

	Year Ended December 31,		
(In millions)	2016	2015	2014
Cash paid (received) for:			
Interest	$86.6	$84.2	$87.5
Income taxes	(3.6)	4.8	69.4

As of December 31, 2016 and 2015, the Company has accruals related to utility and nonutility plant purchases totaling approximately $30.0 million and $19.4 million, respectively.

24. Impact of Recently Issued Accounting Guidance

Revenue Recognition Guidance

In May 2014, the FASB issued new accounting guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for GAAP. The amendments in this guidance state that an entity should recognize revenue to depict the transfer of promised 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. This new guidance requires improved disclosures to help users of financial statements better understand the nature, amount, timing, and uncertainty of revenue that is recognized. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). While the Company continues to assess the standard and initial conclusions could change based on completion of that assessment, the Company preliminarily plans to adopt the guidance under the modified retrospective method.

On July 9, 2015, the FASB approved a one year deferral that became effective through an ASU in August and changed the effective date to annual reporting periods beginning after December 15, 2017, including interim periods, with early adoption permitted, but not before the original effective date of December 15, 2016.

The Company is currently assessing the impacts this guidance may have on the Consolidated Balance Sheets, Consolidated Statements of Operations, and disclosures including the ability to recognize revenue for certain contracts, and its accounting for contributions in aid of construction (CIAC). While management will continue to analyze the impact of this new standard and the related ASUs that clarify guidance in the standard, at this time, management does not believe adoption of the standard will have a significant impact on the Company's pattern of revenue recognition. The Company plans to adopt the guidance effective January 1, 2018.

Simplifying the Presentation of Debt Issuance Costs
In April 2015, the FASB issued new accounting guidance on accounting for debt issuance costs which changes the presentation of debt issuance costs in financial statements. This ASU requires an entity to present such costs in the balance sheet as a direct reduction from the related debt liability rather than as an asset. Amortization of the costs will continue to be reported as interest expense. This ASU is effective for annual reporting periods beginning after December 15, 2015. The guidance was adopted as of January 1, 2016 and has been applied retrospectively to all periods presented. The effect of the change on the December 31, 2015 balance sheet was the reclassification of $8.6 million from Regulatory assets to Long-term Debt and the reclassification of $1.3 million from Other assets to Long-term Debt. The reclassification had no material impact on the Company's financial condition, results of operations, or cash flows as a result of the adoption.

Leases
In February 2016, the FASB issued new accounting guidance for the recognition, measurement, presentation and disclosure of leasing arrangements. This ASU requires the recognition of lease assets and liabilities for those leases currently classified as operating leases while also refining the definition of a lease. In addition, lessees will be required to disclose key information about the amount, timing, and uncertainty of cash flows arising from leasing arrangements. This ASU is effective for the interim and annual reporting periods beginning January 1, 2019, although it can be early adopted, with a modified retrospective approach for leases that commenced prior to the date of adoption. The Company is currently evaluating the standard to determine the impact it will have on the financial statements.

Stock Compensation
In March 2016, the FASB issued new accounting guidance which is intended to simplify several aspects of accounting for share-based payment transactions, including the income tax consequences. This ASU is effective for annual periods beginning after December 15, 2016, and relevant interim periods. Early application is permitted. Most of the Company's share based awards are settled via cash payments and are therefore not impacted by this standard. The Company does not anticipate adoption of the standard to have a significant impact on the financial statements.

Other Recently Issued Standards
Management believes that other recently issued standards, which are not yet effective, will not have a material impact on the Company's financial position, results of operations, or cash flows upon adoption.

25. Quarterly Financial Data (Unaudited)

Information in any one quarterly period is not indicative of annual results due to the seasonal variations common to the Company’s utility operations. Summarized quarterly financial data for 2016 and 2015 follows:

(In millions, except per share amounts)	Q1	Q2	Q3	Q4
2016				
Operating revenues	$584.8	$533.7	$631.0	$699.0
Operating income	92.2	63.9	105.5	120.7
Net income	48.3	32.3	61.4	69.6
Earnings per share:				
Basic and Diluted	$0.58	$0.39	$0.74	$0.84
2015				
Operating revenues	$706.2	$551.0	$573.5	$604.0
Operating income	106.1	72.9	79.9	103.0
Net income	57.0	35.8	39.3	65.2
Earnings per share:				
Basic and Diluted	$0.69	$0.43	$0.48	$0.79

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Changes in Internal Controls over Financial Reporting

During the quarter ended December 31, 2016, there have been no changes to the Company’s internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of December 31, 2016, the Company conducted an evaluation under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer of the effectiveness and the design and operation of the Company's disclosure controls and procedures. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective as of December 31, 2016, to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is:

1) recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and
2) accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Management’s Report on Internal Control over Financial Reporting

Vectren Corporation’s management is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision and with the participation of management, including the Chief Executive

Officer and Chief Financial Officer, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation under the framework in Internal Control — Integrated Framework (2013), the Company concluded that its internal control over financial reporting was effective as of December 31, 2016.

The effectiveness of internal control over financial reporting as of December 31, 2016, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included in Item 8 of this annual report.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by Part III, Item 10 of this Form 10-K is incorporated by reference herein, and made part of this Form 10-K, from the Company's Proxy Statement for its 2017 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission pursuant to Regulation 14A, within 120 days after the end of the fiscal year. The Company’s executive officers are the same as those named executive officers detailed in the Proxy Statement.

Corporate Code of Conduct

The Company’s Corporate Governance Guidelines; the charters for each committee of the Board of Directors; its Corporate Code of Conduct that covers the Company’s Board members, officers and employees; and its Board Code of Ethics and Code of Conduct that also applies to the Company’s Board members are available in the Corporate Governance section of the Company’s website, www.vectren.com. The Corporate Code of Conduct (titled “Corp Code of Conduct”) contains specific acknowledgments pertaining to executive officers. A separate code of conduct (titled “Board Code of Ethics & Code of Conduct”) contains specific codes of ethics pertaining to the Board of Directors. A copy will be mailed upon request to Investor Relations, One Vectren Square, Evansville, Indiana 47708. The Company will disclose any amendments to the Corporate Code of Conduct/Board Code of Ethics & Code of Conduct or waivers of the Corporate Code of Conduct on behalf of the Company’s directors or officers including, but not limited to, the principal executive officer, principal financial and accounting officer, and persons performing similar functions on the Company’s website at the Internet address set forth above promptly following the date of such amendment or waiver and such information will also be available by mail upon request to the address listed above.

ITEM 11. EXECUTIVE COMPENSATION

Information required by Part III, Item 11 of this Form 10-K is incorporated by reference herein, and made part of this Form 10-K, from the Company's Proxy Statement for its 2017 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission pursuant to Regulation 14A, within 120 days after the end of the fiscal year.

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

Except with respect to equity compensation plan information of the Registrant, which is included herein, the information required by Part III, Item 12 of this Form 10-K is incorporated by reference herein, and made part of this Form 10-K, from the Company's Proxy Statement for its 2017 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission pursuant to Regulation 14A, within 120 days after the end of the fiscal year.

Shares Issuable under Share-Based Compensation Plans

As of December 31, 2016, the following shares were authorized to be issued under share-based compensation plans:

	A	B	C
Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	—	$ —	3,273,540 (1)
Equity compensation plans not approved by security holders	—	—	—
Total	—	$ —	3,273,540

(1) After December 31, 2016, and as of February 21, 2017, the following share-based units were issued under the Plan: 185,290 to named and non-named executive officers of the Company, and 18,600 to members of the Board of Directors. Based upon the performance measure of the 2014 grant, as approved by the Compensation and Benefits Committee of the Board of Directors on February 21, 2017, 151,414 share-based units were issued to named and non-named executive officers, including former retirees whose 2014 grants also remained subject to performance.

The At-Risk Compensation Plan was approved by Vectren Corporation common shareholders after the merger forming Vectren and was most recently amended and reapproved at the 2016 annual meeting of shareholders.

ITEM 13. CERTAIN RELATIONSHIPS, RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information required by Part III, Item 13 of this Form 10-K is incorporated by reference herein, and made part of this Form 10-K, from the Company's Proxy Statement for its 2017 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission pursuant to Regulation 14A, within 120 days after the end of the fiscal year.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required by Part III, Item 14 of this Form 10-K is incorporated by reference herein, and made part of this Form 10-K, from the Company's Proxy Statement for its 2017 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission pursuant to Regulation 14A, within 120 days after the end of the fiscal year.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

List of Documents Filed as Part of This Report

Consolidated Financial Statements
The consolidated financial statements and related notes, together with the reports of Deloitte & Touche LLP, appear in Part II "Item 8 Financial Statements and Supplementary Data" of this Form 10-K.

Supplemental Schedules
For the years ended December 31, 2016, 2015, and 2014, the Company's Schedule II -- Valuation and Qualifying Accounts Consolidated Financial Statement Schedules is presented herein. The report of Deloitte & Touche LLP on the schedule may be found in Item 8. All other schedules are omitted as the required information is inapplicable or the information is presented in the Consolidated Financial Statements or related notes in Item 8.

SCHEDULE II
Vectren Corporation and Subsidiaries
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Year	Charged to Expenses	Charged to Other Accounts	Deductions from Reserves, Net	Balance at End of Year
(In millions)					
VALUATION AND QUALIFYING ACCOUNTS:					
Year 2016 – Accumulated provision for uncollectible accounts	$ 5.6	$ 6.9	$ —	$ 6.5	$ 6.0
Year 2015 – Accumulated provision for uncollectible accounts	$ 6.0	$ 8.1	$ —	$ 8.5	$ 5.6
Year 2014 – Accumulated provision for uncollectible accounts	$ 6.8	$ 7.3	$ —	$ 8.1	$ 6.0
Year 2016 – Reserve for impaired notes receivable	$ 0.2	$ 0.4	$ —	$ —	$ 0.6
Year 2015 – Reserve for impaired notes receivable	$ —	$ 0.2	$ —	$ —	$ 0.2
Year 2014 – Reserve for impaired notes receivable	$ 0.6	$ —	$ —	$ 0.6	$ —
OTHER RESERVES:					
Year 2016 - Restructuring costs	$ —	$ —	$ —	$ —	$ —
Year 2015 - Restructuring costs	$ —	$ —	$ —	$ —	$ —
Year 2014 - Restructuring costs	$ 0.2	$ —	$ —	$ 0.2	$ —

List of Exhibits

The Company has incorporated by reference herein certain exhibits as specified below pursuant to Rule 12b-32 under the Exchange Act. Exhibits for the Company attached to this filing filed electronically with the SEC are listed below. Exhibits for the Company are listed in the Index to Exhibits.

Vectren Corporation
Form 10-K
Attached Exhibits

The following Exhibits were filed electronically with the SEC with this filing.

Exhibit Number	Document
10.11	Vectren Corporation Executive Severance Plan as amended and restated February 21, 2017
10.24	Vectren Corporation At Risk Compensation Plan (specimen unit award agreement for officers, effective January 1, 2017)
21.1	List of Company's Significant Subsidiaries
23.1	Consent of Independent Registered Public Accounting Firm
31.1	Chief Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Chief Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Calculation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase

INDEX TO EXHIBITS

3. Articles of Incorporation and By-Laws

3.1	Amended and Restated Articles of Incorporation of Vectren Corporation effective March 31, 2000. (Filed and designated in Current Report on Form 8-K filed April 14, 2000, File No. 1-15467, as Exhibit 4.1.)
3.2	Code of By-Laws of Vectren corporation as most recently amended as of February 1, 2017 (filed and designated in Form 8-K, dated February 1, 2017, File No. 1-15467, as Exhibit 3.1)

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4. Instruments Defining the Rights of Security Holders, Including Indentures

4.1	Mortgage and Deed of Trust dated as of April 1, 1932 between Southern Indiana Gas and Electric Company and Bankers Trust Company, as Trustee, and Supplemental Indentures thereto dated August 31, 1936, October 1, 1937, March 22, 1939, July 1, 1948, June 1, 1949, October 1, 1949, January 1, 1951, April 1, 1954, March 1, 1957, October 1, 1965, September 1, 1966, August 1, 1968, May 1, 1970, August 1, 1971, April 1, 1972, October 1, 1973, April 1, 1975, January 15, 1977, April 1, 1978, June 4, 1981, January 20, 1983, November 1, 1983, March 1, 1984, June 1, 1984, November 1, 1984, July 1, 1985, November 1, 1985, June 1, 1986. (Filed and designated in Registration No. 2-2536 as Exhibits B-1 and B-2; in Post-effective Amendment No. 1 to Registration No. 2-62032 as Exhibit (b)(4)(ii), in Registration No. 2-88923 as Exhibit 4(b)(2), in Form 8-K, File No. 1-3553, dated June 1, 1984 as Exhibit (4), File No. 1-3553, dated March 24, 1986 as Exhibit 4-A, in Form 8-K, File No. 1-3553, dated June 3, 1986 as Exhibit (4).) July 1, 1985 and November 1, 1985 (Filed and designated in Form 10-K, for the fiscal year 1985, File No. 1-3553, as Exhibit 4-A.) November 15, 1986 and January 15, 1987. (Filed and designated in Form 10-K, for the fiscal year 1986, File No. 1-3553, as Exhibit 4-A.) December 15, 1987. (Filed and designated in Form 10-K, for the fiscal year 1987, File No. 1-3553, as Exhibit 4-A.) December 13, 1990. (Filed and designated in Form 10-K, for the fiscal year 1990, File No. 1-3553, as Exhibit 4-A.) April 1, 1993. (Filed and designated in Form 8-K, dated April 13, 1993, File No. 1-3553, as Exhibit 4.) June 1, 1993 (Filed and designated in Form 8-K, dated June 14, 1993, File No. 1-3553, as Exhibit 4.) May 1, 1993. (Filed and designated in Form 10-K, for the fiscal year 1993, File No. 1-3553, as Exhibit 4(a).) July 1, 1999. (Filed and designated in Form 10-Q, dated August 16, 1999, File No. 1-3553, as Exhibit 4(a).) March 1, 2000. (Filed and designated in Form 10-K for the year ended December 31, 2001, File No. 1-15467, as Exhibit 4.1.) August 1, 2004. (Filed and designated in Form 10-K for the year ended December 31, 2004, File No. 1-15467, as Exhibit 4.1.) October 1, 2004. (Filed and designated in Form 10-K for the year ended December 31, 2004, File No. 1-15467, as Exhibit 4.2.) April 1, 2005 (Filed and designated in Form 10-K for the year ended December 31, 2007, File No 1-15467, as Exhibit 4.1) March 1, 2006 (Filed and designated in Form 10-K for the year ended December 31, 2007, File No 1-15467, as Exhibit 4.2) December 1, 2007 (Filed and designated in Form 10-K for the year ended December 31, 2007, File No 1-15467, as Exhibit 4.3) August 1, 2009 (Filed and designated in Form 10-K, for the year ended December 31, 2009, File No. 1-15467, as Exhibit 4.1) April 1, 2013 (filed and designated in Form 8-K, dated April 30, 2013, File No. 1-15467, as Exhibit 4.1) September 1, 2014 (filed and designated in Form 8-K dated September 25, 2014 File No. 1-15467, as Exhibit 4.1) September 1, 2015 (filed and designated in Form 8-K dated September 10, 2015 File No. 1-15467, as Exhibit 4.1)
4.2	Indenture dated February 1, 1991, between Indiana Gas and U.S. Bank Trust National Association (formerly known as First Trust National Association, which was formerly known as Bank of America Illinois, which was formerly known as Continental Bank, National Association. Inc.'s. (Filed and designated in Current Report on Form 8-K filed February 15, 1991, File No. 1-6494.); First Supplemental Indenture thereto dated as of February 15, 1991. (Filed and designated in Current Report on Form 8-K filed February 15, 1991, File No. 1-6494, as Exhibit 4(b).); Second Supplemental Indenture thereto dated as of September 15, 1991, (Filed and designated in Current Report on Form 8-K filed September 25, 1991, File No. 1-6494, as Exhibit 4(b).); Third supplemental Indenture thereto dated as of September 15, 1991 (Filed and designated in Current Report on Form 8-K filed September 25, 1991, File No. 1-6494, as Exhibit 4(c).); Fourth Supplemental Indenture thereto dated as of December 2, 1992, (Filed and designated in Current Report on Form 8-K filed December 8, 1992, File No. 1-6494, as Exhibit 4(b).); Fifth Supplemental Indenture thereto dated as of December 28, 2000, (Filed and designated in Current Report on Form 8-K filed December 27, 2000, File No. 1-6494, as Exhibit 4.)

4.3	Indenture dated October 19, 2001, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated October 19, 2001, File No. 1-16739, as Exhibit 4.1); First Supplemental Indenture, dated October 19, 2001, between Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated October 19, 2001, File No. 1-16739, as Exhibit 4.2); Second Supplemental Indenture, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated November 29, 2001, File No. 1-16739, as Exhibit 4.1); Third Supplemental Indenture, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated July 24, 2003, File No. 1-16739, as Exhibit 4.1); Fourth Supplemental Indenture, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated November 18, 2005, File No. 1-16739, as Exhibit 4.1). Form of Fifth Supplemental Indenture, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas & Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated October 16, 2006, File No. 1-16739, as Exhibit 4.1). Sixth Supplemental Indenture, dated March 10, 2008, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank National Association (Filed and designated in Form 8-K, dated March 10, 2008, File No. 1-16739, as Exhibit 4.1)
4.4	Note Purchase Agreement, dated March 11, 2009, among Vectren Corporation, Vectren Capital, Corp. and each of the purchasers named therein. (Filed and designated in Form 8-K dated March 16, 2009 File No. 1-15467, as Exhibit 4.5)
4.5	Note Purchase Agreement, dated April 7, 2009, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company and Vectren Energy Delivery of Ohio, Inc. and the purchasers named therein. (Filed and designated in Form 8-K dated April 7, 2009 File No. 1-15467, as Exhibit 4.5)
4.6	Note Purchase Agreement, dated September 9, 2010, among Vectren Capital, Corp. and the purchasers named therein. (Filed and designated in Form 8-K dated September 10, 2010 File No. 1-15467, as Exhibit 4.1)
4.7	Note Purchase Agreement, dated April 5, 2011, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company and Vectren Energy Delivery of Ohio, Inc. and the purchasers named therein. (Filed and designated in Form 8-K dated April 8, 2011 File No. 1-15467, as Exhibit 4.1)
4.8	Note Purchase Agreement, dated November 15, 2011, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company and Vectren Energy Delivery of Ohio, Inc. and the purchasers named therein. (Filed and designated in Form 8-K dated November 17, 2011 File No. 1-15467, as Exhibit 4.1)
4.9	Note Purchase Agreement, dated December 20, 2012, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company and Vectren Energy Delivery of Ohio, Inc. and the purchasers named therein. (Filed and designated in Form 8-K dated December 21, 2012 File No. 1-15467, as Exhibit 4.1)
4.10	Note Purchase Agreement, dated August 22, 2013, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, and Vectren Energy Delivery of Ohio, Inc., and the purchasers named therein. (Filed and designated in Form 8-K dated August 2, 2013, File No. 1-15467, as Exhibit 4.1)
4.11	Note Purchase Agreement, dated June 11, 2015, between Vectren Utility Holding, Inc. and each of the purchasers named therein. (Filed and designated in Form 8-K dated June 12, 2015 File No. 1-15467, as Exhibit 4.1).

4.12	Note Purchase Agreement, dated June 11, 2015, between Vectren Capital, Corp. and each of the purchasers named therein. (Filed and designated in Form 8-K dated June 12, 2015 File No. 1-15467, as Exhibit 4.2).

10. Material Contracts

10.1	Vectren Corporation At Risk Compensation Plan effective May 1, 2001, (as most recently amended and restated as of May 24, 2016). (Filed and designated in Form 10-Q for the quarter ended June 30, 2016, File No. 1-15467, as Exhibit 10.1.)
10.2	Vectren Corporation Non-Qualified Deferred Compensation Plan, as amended and restated effective January 1, 2001. (Filed and designated in Form 10-K, for the year ended December 31, 2001, File No. 1-15467, as Exhibit 10.32.)
10.3	Vectren Corporation Non-Qualified Deferred Compensation Plan, effective January 1, 2005. (Filed and designated in Form 8-K dated September 29, 2008, File No. 1-15467, as Exhibit 10.3.)
10.4	Vectren Corporation Unfunded Supplemental Retirement Plan for a Select Group of Management Employees (As Amended and Restated Effective January 1, 2005). (Filed and designated in Form 8-K dated December 17, 2008, File No. 1-15467, as Exhibit 10.1.)
10.5	Vectren Corporation Specimen Waiver, effective October 3, 2013, to the Vectren Corporation Unfunded Supplemental Retirement Plan for a Select Group of Management Employees. (Filed and designated in Form 10-Q for the quarter ended September 30, 2013, File No. 1-15467, as Exhibit 10.1)
10.6	Vectren Corporation Nonqualified Defined Benefit Restoration Plan (As Amended and Restated Effective January 1, 2005). (Filed and designated in Form 8-K dated December 17, 2008, File No. 1-15467, as Exhibit 10.2.)
10.7	Vectren Corporation At Risk Compensation Plan specimen unit award agreement for officers, effective January 31, 2013. (Filed and designated in Form 10-K for the year ended December 31, 2012, File No. 1-15467, as Exhibit 10.2)
10.8	Vectren Corporation At Risk Compensation Plan specimen unit award agreement for officers, effective January 17, 2014. (Filed in Form 10-K herewith as Exhibit 10.14)
10.9	Vectren Corporation specimen change in control agreement dated December 31, 2011. (Filed and designated in Form 8-K, dated January 5, 2012, File No. 1-15467, as Exhibit 10.1)
10.10	Amendment Number One to the Vectren Corporation specimen change in control agreement dated December 31, 2012. (Filed and designated in Form 10-K for the year ended December 31, 2012, File No. 1-15467, as Exhibit 10.1)
10.11	Vectren Corporation Executive Severance Plan dated December 31, 2011, as most recently amended and restated as of February 21, 2017. (Filed in Form 10-K herewith as Exhibit 10.11). The severance plan differs among the named executive officers only to the extent where severance benefits are provided in the amount of two times base salary for Mr. Chapman and one and one half times base salary for Messer's Schach and Christian and Ms. Hardwick.
10.12	Gas Sales and Portfolio Administration Agreement between Indiana Gas Company, Inc. and ProLiance Energy, LLC, effective April 1, 2012. (Filed and designated in Form 10-K for the year ended December 31, 2012, File No. 1-15467, as Exhibit 10.3)
10.13	Gas Sales and Portfolio Administration Agreement between Southern Indiana Gas and Electric Company and ProLiance Energy, LLC, effective April 1, 2012. (Filed and designated in Form 10-K for the year ended December 31, 2012, File No. 1-15467, as Exhibit 10.4)
10.14	Formation Agreement among Indiana Energy, Inc., Indiana Gas Company, Inc., IGC Energy, Inc., Indiana Energy Services, Inc., Citizens Energy Group, Citizens Energy Services Corporation and ProLiance Energy, LLC, effective March 15, 1996. (Filed and designated in Form 10-Q for the quarterly period ended March 31, 1996, File No. 1-9091, as Exhibit 10-C.)

10.15	Amendment Number Two to the Vectren Corporation Change in Control Agreement (specimen), dated October 1, 2014. The specimen agreement differs among the named executive officers only to the extent change in control benefits are provided in the amount of three times base salary and bonus for Mr. Chapman and two times base salary and bonus for Mr. Christian, Mr. Schach and Ms. Hardwick. (Filed and designated in Form 8-K, dated September 29, 2014, File No. 1-5467, as Exhibit 10.1)
10.16	Credit Agreement, dated as of October 31, 2014, among Vectren Utility Holdings, Inc., as borrower (Vectren Utility); certain subsidiaries of Vectren Utility, as guarantors; Bank of America, N.A., as administrative agent, swing line lender and a letter of credit issuer; Wells Fargo Bank, National Association, JPMorgan Chase Bank, N.A. and MUFG Union Bank, N.A., as co-syndication agents and letter of credit issuers; and the other lenders named therein. (Filed and designated in Form 8-K, dated November 5, 2014, File No. 1-5467, as Exhibit 10.1)
10.17	Credit Agreement, dated as of October 31, 2014, among Vectren Capital, Corp., as borrower; Vectren Corporation, as guarantor; Wells Fargo Bank, National Association, as administrative agent, swing line lender and a letter of credit issuer; Bank of America, N.A., JPMorgan Chase Bank, N.A. and MUFG Union Bank, N.A., as co-syndication agents and letter of credit issuers; and the other lenders named therein. (Filed and designated in Form 8-K, dated November 5, 2014, File No. 1-5467, as Exhibit 10.2)
10.18	Vectren Corporation At Risk Compensation Plan Stock Unit Awards Award Agreement (Officer) - specimen. (Filed and designated in Form 8-K, dated December 23, 2014, File No. 1-5467, as Exhibit 10.1)
10.19	Grant Agreement for Non-Employee Director Stock Grant - specimen, dated December 31, 2014. (Filed and designated in Form 8-K, dated January 2, 2015, File No. 1-5467, as Exhibit 10.1)
10.20	Coal Supply Agreement for A.B. Brown Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., effective January 1, 2015. Contract assigned to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 10-Q dated March 31, 2015, File No. 1-15467, as Exhibit 10.2.) Portions of the document have been omitted and filed separately pursuant to a request for confidential treatment filed with the Securities and Exchange Commission which was granted.
10.21	Coal Supply Agreement for F.B. Culley Generating Station between Southern Indiana Gas and Vectren Fuels, Inc., effective January 1, 2015. Contract assigned to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 10-Q dated March 31, 2015, File No. 1-15467, as Exhibit 10.3.) Portions of the document have been omitted and filed separately pursuant to a request for confidential treatment filed with the Securities and Exchange Commission which was granted.
10.22	Coal Supply Agreement for Warrick 4 Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., effective January 1, 2015. Contract assigned to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 10-Q dated March 31, 2015, File No. 1-15467, as Exhibit 10.4.) Portions of the document have been omitted and filed separately pursuant to a request for confidential treatment filed with the Securities and Exchange Commission which was granted.
10.23	Vectren Director and Officer Indemnification Agreement (specimen) Deferred Compensation Plan, as amended and restated effective January 1, 2001. (Filed and designated in Form 10-K, for the year ended December 31, 2015, File No. 1-15467, as Exhibit 10.26)
10.24	

Vectren Corporation At Risk Compensation Plan specimen unit award agreement for officers, effective January 1, 2017. (Filed in Form 10-K herewith as Exhibit 10.24)

21. Subsidiaries of the Company
The list of the Company's significant subsidiaries is attached hereto as Exhibit 21.1. (Filed herewith.)

23. Consents of Experts and Counsel
The consents of Deloitte & Touche LLP are attached hereto as Exhibit 23.1. (Filed herewith.)

31. Certification Pursuant To Section 302 of the Sarbanes-Oxley Act of 2002
Chief Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act Of 2002 is attached hereto as Exhibit 31.1 (Filed herewith.)

Chief Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act Of 2002 is attached hereto as Exhibit 31.2 (Filed herewith.)

32. Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
Certification Pursuant To Section 906 of the Sarbanes-Oxley Act Of 2002 is attached hereto as Exhibit 32 (Filed herewith.)

101 Interactive Data File

101.INS XBRL Instance Document (Filed herewith.)

101.SCH XBRL Taxonomy Extension Schema (Filed herewith.)

101.CAL XBRL Taxonomy Extension Calculation Linkbase (Filed herewith.)

101.DEF XBRL Taxonomy Extension Definition Linkbase (Filed herewith.)

101.LAB XBRL Taxonomy Extension Labels Linkbase (Filed herewith.)

101.PRE XBRL Taxonomy Extension Presentation Linkbase (Filed herewith.)

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

VECTREN CORPORATION

Dated February 23, 2017 /s/ Carl L.
Chapman
Carl L. Chapman,
Chairman, President, and Chief Executive Officer

Pursuant to the requirements of the Securities and Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in capacities and on the dates indicated.

Signature	Title	Date
/s/ Carl L. Chapman Carl L. Chapman	Chairman, President, and Chief Executive Officer (Principal Executive Officer)	February 23, 2017
/s/ M. Susan Hardwick M. Susan Hardwick	Executive Vice President and Chief Financial Officer (Principal Accounting and Financial Officer)	February 23, 2017
/s/ James H. DeGraffenreidt James H. DeGraffenreidt	Director	February 23, 2017
/s/ John D. Engelbrecht John D. Engelbrecht	Director	February 23, 2017
/s/ Anton H. George Anton H. George	Director	February 23, 2017
/s/ Martin C. Jischke Martin C. Jischke	Director	February 23, 2017

/s/ Robert G. Jones Robert G. Jones	Director	February 23, 2017
/s/ Patrick K. Mullen Patrick K. Mullen	Director	February 23, 2017
/s/ R. Daniel Sadlier R. Daniel Sadlier	Director	February 23, 2017
/s/ Michael L. Smith Michael L. Smith	Director	February 23, 2017
/s/ Teresa J. Tanner Teresa J. Tanner	Director	February 23, 2017
/s/ Jean L. Wojtowicz Jean L. Wojtowicz	Director	February 23, 2017