VECTREN UTILITY HOLDINGS INC
Form 10-K
March 09, 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: 1-16739

VECTREN UTILITY HOLDINGS, INC.

(Exact name of registrant as specified in its charter)

INDIANA	35-2104850
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
One Vectren Square	47708
(Address of principal executive offices)	(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
Vectren Utility 6.10% SR NTS 12/1/2035	New York Stock Exchange

1

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

Title of each class	Name of each exchange on which registered
Common – Without Par	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 ¨
*Utility Holdings is a majority owned subsidiary of a well-known seasoned issuer, and well-known seasoned issuer status depends in part on the type of security being registered by the majority-owned subsidiary.

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 ¨ Accelerated filer ¨

Non-accelerated filer ý Smaller reporting company ¨
(Do not check if a 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 zero. All shares outstanding of the Registrant's common stock were held by Vectren Corporation.

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	10	February 28, 2017
Class	Number of Shares	Date

Omission of Information by Certain Wholly Owned Subsidiaries

The Registrant is a wholly owned subsidiary of Vectren Corporation and meets the conditions set forth in General Instructions (I)(1)(a) and (b) of Form 10-K and is therefore filing with the reduced disclosure format contemplated thereby.

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 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, including those of Vectren Utility Holdings, Inc., 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

3

Table of Contents

(A) – Omitted or amended as the Registrant is a wholly owned subsidiary of Vectren Corporation and meets the conditions set forth in General Instructions (I)(1)(a) and (b) of Form 10-K and is therefore filing with the reduced disclosure format contemplated thereby.

PART I
ITEM 1. BUSINESS

Description of the Business

Vectren Utility Holdings, Inc. (the Company, Utility Holdings or VUHI), an Indiana corporation, was formed on March 31, 2000 to serve as the intermediate holding company for Vectren Corporation’s (Vectren or the Company's parent) three operating 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). Herein, 'the Company' may also refer to Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Inc. and/or Vectren Energy Delivery of Ohio, Inc. The Company also has other assets that provide information technology and other services to the three utilities. Vectren, an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana and was organized on June 10, 1999. Both Vectren and the Company are holding companies as defined by the Energy Policy Act of 2005.

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.

Narrative Description of the Business

The Company has 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.

At December 31, 2016, the Company had $5.0 billion in total assets, with approximately $3.1 billion attributed to Gas Utility Services, $1.8 billion attributed to Electric Utility Services, and $0.1 billion attributed to Other Operations. Net income for the year ended December 31, 2016, was $173.6 million, with $76.1 million attributed to Gas Utility Services, $84.7 million attributed to Electric Utility Services, and $12.8 million attributed to Other Operations. Net income for the year ended December 31, 2015, was $160.9 million. For further information regarding the activities and assets of operating segments, refer to Note 13 in the Consolidated Financial Statements included in Item 8.

Following is a more detailed description of the Gas Utility Services and Electric Utility Services operating segments. Other Operations are not significant.

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; and ethanol. 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 has 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 Ohio service territory. As a result, substantially all of the 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, the Company 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. 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, Inc. (Vectren Fuels) and one other supplier to provide supply for its generating units. Vectren Fuels was also a wholly owned subsidiary of the Company's parent. 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 existing coal supply contracts as well as enter into new long-term contracts in order to secure coal with specifications that support SIGECO's 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 SIGECO 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, SIGECO 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, SIGECO 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" 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.

Personnel

As of December 31, 2016, the Company and its consolidated subsidiaries had approximately 1,600 employees, of which 700 are subject to collective bargaining arrangements.

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.

ITEM 1A. RISK FACTORS

Investors should consider carefully the following factors that could cause the Company's operating results and financial condition to be materially adversely affected.

The Company is a holding company and its assets consist primarily of investments in its subsidiaries.

The ability of the Company to pay dividends to the Company's parent and repay indebtedness depends on the earnings, financial condition, capital requirements and cash flow of its subsidiaries, SIGECO, Indiana Gas, and VEDO and the distribution of those earnings to the Company. Should the earnings, financial condition, capital requirements or cash flow of, or legal requirements applicable to them restrict their ability to pay dividends or make other payments to the Company, its ability to pay dividends to its parent could be limited. 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 interest costs, uncollectible accounts expense, and allocated pension costs.

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's parent 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.

The Company has long-term and short-term debt guaranteed by its subsidiaries.

The Company currently has outstanding long-term and short-term debt that is jointly and severally guaranteed by SIGECO, Indiana Gas, and VEDO. Such debt obligations are not guaranteed by the Company's parent. These guarantees do not represent incremental consolidated obligations; rather, they represent guarantees of the Company's obligations.

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

The following table shows the current ratings assigned to certain outstanding debt by Moody's and Standard & Poor's:

	Current Rating	
	Moody's	Standard & Poor's
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's parent 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.

The Company may need to raise additional capital in the future. The Company may raise additional funds through debt offerings and 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, or make investments.

The Company'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; and ethanol. 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.

The Company operates 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 the Company'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.

The Company's businesses are exposed to increasing regulation, including pipeline safety, environmental, and cybersecurity regulation.

The Company is 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 can charge customers, the rate of return that the Company is authorized to earn, and it's 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 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 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 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 the Company's utility rates charged to customers, its costs, and its profitability.

Any additional expenses or capital incurred by the Company, 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.

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 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.

The Company's 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 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.

The Company's 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 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 has 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.

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 derivative regulation 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.

From time to time, the Company 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 sponsored by the Company's parent and other factors impacting pension plan costs could impact the Company’s liquidity and results of operations.

The costs associated with retirement plans sponsored by the Company's parent, 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 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 the Company’s facilities and operations and corporate reputation.

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. 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 the Company'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 information 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 the Company'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.

The Company'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.

The Company 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.

The performance of the Company's parent and it's nonutility businesses may impact the Company.

Execution of Vectren’s nonutility business strategies, specifically Vectren Infrastructure Services Corporation (VISCO), are subject to a number of risks.

VISCO is wholly owned by the Company's parent and provides underground pipeline construction and repair services for customers including the Company. Risks specific to VISCO's strategies include, but are not limited to, success in bidding contracts; variations in the volume of contract work; unanticipated cost increases in completion of the contracted work; increases to funding requirements associated with multiemployer pension plans; the ability to attract and retain qualified employees; ability to obtain materials and equipment required to perform services from suppliers and manufacturers.

In addition, there are other risks impacting nonutility operations including the effects of weather; failure of installed performance contracting products to operate as planned; failure to develop or obtain gas storage field; creditworthiness of customers and joint venture partners; changes in federal, state or local legal requirements, such as changes in tax laws or rates; and changing market conditions.

The nonutility infrastructure services business supports the Company's utilities pursuant to infrastructure service contracts. In most instances, the ability to maintain these service contracts depends upon regulatory discretion and negotiation with interveners, and there can be no assurance that it will be able to obtain future service contracts, or that existing arrangements will not be revisited.

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.

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

Common Stock Market Price

All of the outstanding shares of the Company's common stock are owned by the Company's parent. The Company's common stock is not traded. There are no outstanding options or warrants to purchase the Company's common equity or securities convertible into the Company's common equity. Additionally, the Company has no plans to publicly offer its common equity securities.

Dividends Paid to Parent

In the first quarter of 2017, the Company paid a $30.6 million dividend to its parent company.

During 2016, the Company paid dividends of $29.0 million to its parent company in each quarter.

During 2015, the Company paid dividends of $27.6 million to its parent company in each quarter.

Dividends on shares of common stock are payable at the discretion of the Board of Directors out of legally available funds. Future payments of dividends, and the amounts of these dividends, will depend on the Company's financial condition, results of operations, capital requirements, and other factors.

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)	2016	2015	2014	2013	2012
Operating Data:					
Operating revenues	$1,377.8	$1,394.5	$1,569.7	$1,429.6	$1,333.6
Operating income	316.5	296.6	281.4	281.6	286.8
Net income	173.6	160.9	148.4	141.8	138.0
Balance Sheet Data:					
Total assets	$5,040.9	$4,592.7	$4,409.3	$4,127.1	$4,032.2
Long-term debt - net of current maturities & debt subject to tender	1,331.0	1,379.2	1,154.8	1,248.9	1,088.8
Common shareholder's equity	1,624.0	1,535.2	1,478.5	1,432.8	1,390.0

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

The Company generates revenue primarily from the delivery of natural gas and electric service to its customers. It's primary source of cash flow 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 utility operations between a Gas Utility Services operating segment and an Electric Utility Services operating segment.

The Company's parent has in place a disclosure committee that consists of senior management as well as financial management. The committee is actively involved in the preparation and review of the Company's SEC filings.

The following discussion and analysis should be read in conjunction with the consolidated financial statements and notes thereto.

Executive Summary of Consolidated Results of Operations

During 2016, the Company earned $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.

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.

The Company'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.

Operating Trends

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.

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, 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, the Company 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 the Company 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 Company's 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 requires 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.

On March 7, 2017, the Court of Appeals reversed the IURC’s finding that the four year cap on lost margin recovery was arbitrary and the IURC failed to properly interpret the governing statute requiring that it review the utility's entire DSM proposal and approve or reject it as a whole, including the proposed lost margin recovery. On remand, the IURC must complete its review and can only reject the Company’s lost margin recovery if found to be unreasonable. Once the Court’s decision is final, the Company will again seek IURC approval of its energy efficiency plan.

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 a corporate sustainability program in 2012 with the publication of the initial corporate sustainability report of the Company's parent. 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 a 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 sustainability policies and efforts, and in particular its policies and procedures designed to ensure compliance with applicable laws and regulations, are directly overseen by Vectren's Corporate Responsibility and Sustainability Committee, as well as vetted with Vectren's 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 is 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 (SO_2), nitrogen oxide (NO_x), 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

The Company, along with the Company's parent, 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;
- The Company’s parent's mission statement and purpose is focused on corporate sustainability and the need to help customers conserve and manage energy costs. The annual sustainability report received Core level certification by the Global Reporting Initiative and demonstrates commitment to sustainability and transparency in operations. The 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.

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.

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. 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. The Company does not have share-based compensation plans separate from the Company's parent; the Company is however allocated costs associated with the plans of the Company's parent. Pursuant to these plans, 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 allocate support services, assets, and its pension and postretirement benefit obligations from the Company's parent. 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.

Goodwill

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. 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 operating segment, and that estimated fair value was compared to its 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 segment's fair value also would have resulted in no impairment charge.

Intercompany Allocations

Support Services
The Company's parent provides corporate, general, and administrative services to the Company and allocates costs to the Company, including costs for share-based compensation and for pension and other postretirement benefits that are not directly charged to subsidiaries. These costs have been allocated using various allocators, including number of employees, number of customers, and/or the level of payroll, revenue contribution, and capital expenditures. Allocations are at cost. Management believes that the allocation methodology is reasonable and approximates the costs that would have been incurred had the Company secured those services on a stand-alone basis. The allocation methodology is not subject to near term changes.

Pension and Other Postretirement Obligations
The Company's parent satisfies the future funding requirements of its pension and other postretirement plans and the payment of benefits from general corporate assets and, as necessary, relies on the Company to support the funding of these obligations. However, the Company has no contractual funding commitment. The Company's parent allocates the periodic cost of its retirement plans calculated pursuant to US GAAP to its subsidiaries. Periodic cost, comprised of service cost and interest on that service cost, is directly charged to the Company based on labor at each measurement date and that cost is charged to operating expense and capital projects, using labor charges as the allocation method. Other components of periodic costs (such as interest cost, asset returns, and amortizations) and the service cost related to the Company's parent level operations are charged to subsidiaries through the allocation process discussed above. Any difference between funding requirements and allocated periodic costs is recognized as an asset or liability until reflected in periodic costs. Neither plan assets nor the ending liability is allocated to individual subsidiaries since these assets and obligations are derived from corporate level decisions. Management believes these direct charges when combined with benefit-related corporate charges discussed in “support services” above approximate costs that would have been incurred if the Company accounted for benefit plans on a stand-alone basis.

The Company's parent 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 pension and postretirement plans. The Company's parent used the following weighted average assumptions to develop 2016 periodic benefit cost: a discount rate of approximately 4.31 percent, an expected return on plan assets of 7.50 percent, a rate of compensation increase of 3.50 percent, and an inflation assumption of 2.50 percent. Due to higher interest rates, the discount rate is approximately 25 basis points higher from the assumption used in 2015. Inflation rates, expected return on plan assets, and rate of compensation increase remained the same from 2015 to 2016. To estimate 2017 costs, the following weighted average assumptions were used: 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. Management updated its mortality assumptions to incorporate this increase in life expectancy. Accordingly, management 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. Management 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. 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. Vectren’s management currently estimates a pension and postretirement cost of approximately $6.6 million in 2017, compared to approximately $5.5 million in 2016, $10 million in 2015, and $9 million in 2014. Approximately $5.5 million of the cost estimated for 2017 will be allocated to the Company.

Vectren's 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

The Company funds the short-term and long-term financing needs of its utility subsidiary operations. The Company's parent does not guarantee the Company's debt. Outstanding long-term and short-term borrowing arrangements are jointly and severally guaranteed by SIGECO, Indiana Gas, and VEDO. The guarantees are full and unconditional and joint and several, and the Company has no subsidiaries other than the subsidiary guarantors. Information about the subsidiary guarantors as a group is included in Note 14 to the consolidated financial statements. Long-term debt and short-term obligations outstanding at December 31, 2016 approximated $996 million and $194 million, respectively. Additionally, prior to the Company's 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 operations have historically been the primary source for Vectren's common stock dividends.

The credit ratings of the senior unsecured debt of the Company 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. The Company's 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 50-60 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 component was 54 percent and 52 percent of long-term capitalization at 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.

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 financing. However, the resources required for capital investment remain uncertain for a variety of factors including, but not limited to, expanded environmental regulations on power generation and regulatory initiatives involving gas pipeline infrastructure replacement. These regulations may result in the need to raise additional capital in the coming years.

The Company 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 the Company and thus receive some of the proceeds from various Company issuances to third parties on the same terms as those obtained by the Company. The majority of the long-term debt needs of the utilities is expected to be met through these debt issuances, 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 and expires in June 2017. On February 22, 2017, orders for long-term financing authority of $160 million and $200 million of long-term debt, and $120 million and $180 million of equity financing, were received from the IURC for SIGECO and Indiana Gas, respectively. These orders expire in March 2019.

Recent Company financings are explained in the discussion of financing cash flow beginning on page 44.

Consolidated Short-Term Borrowing Arrangements
At December 31, 2016, the Company had $350 million of short-term borrowing capacity. As reduced by borrowings outstanding at December 31, 2016, approximately $156 million was available. This short-term credit facility is available through October 31, 2019. The maximum limit of the facility remained unchanged. This facility is used to supplement working capital needs and also to fund capital investments and debt redemptions until financed on a long-term basis.

The Company has historically funded the short-term borrowing needs through the commercial paper market and expects to use the short-term borrowing facility in instances where the commercial paper market is not efficient. Following is certain information regarding these short-term borrowing arrangements.

(In millions)	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 %
Annual Average			
Balance Outstanding	$59.8	$53.8	$35.6
Weighted Average Interest Rate	0.71 %	0.38 %	0.34 %
Maximum Month End Balance Outstanding	$194.4	$121.5	$156.4

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

Proceeds from Stock Plans and Additional Capital Contributions
The Company's parent may periodically reallocate capital or issue new common shares to satisfy dividend reinvestment plan and other employee benefit plan requirements and contribute those proceeds to the Company. In 2016, additional capital of $25.0 million was received from the nonutility operations of the Company's parent to partially fund the Company's capital expenditure program. In addition, issues of new common shares for the Company's parent's dividend reinvestment plan in 2016, 2015, and 2014 added additional liquidity to the Company of $6.3 million, $6.2 million and $6.0 million, respectively.

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

Planned Capital Expenditures
During 2016, capital expenditures approximated $500 million, compared to $400 million in 2015 and $350 million in 2014. Planned 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; however, many environmental and pipeline safety standards are subject to change in the near term. Such changes could materially impact planned capital expenditures.

Pension and Postretirement Funding Obligations
As of December 31, 2016, assets related to the Company's parent's qualified pension plans were approximately 92 percent of the projected benefit obligation on a GAAP basis and 124 percent of the target liability for ERISA purposes. The Company's parent currently does not anticipate funding these plans in 2017.

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

	Total	2017	2018	2019	2020	2021	Thereafter
Long-term debt (1)	$ 1,380.1	$ 49.1	$ 100.0	$ —	$ 100.0	$ 55.0	$ 1,076.0
Short-term debt	194.4	$ 194.4	—	—	—	—	—
Long-term debt interest commitments	1,006.1	65.6	62.4	59.1	54.5	52.6	711.9
Plant purchase commitments	5.9	4.4	1.5	—	—	—	—
Operating leases	5.0	$ 0.8	$ 0.8	$ 0.6	$ 0.6	$ 0.6	$ 1.6
Total (2)	$ 2,591.5	$ 314.3	$ 164.7	$ 59.7	$ 155.1	$ 108.2	$ 1,789.5

(1) The debt due in 2017 is comprised of debt issued by SIGECO

(2) The Company has other long-term liabilities that total approximately $163 million. This amount is comprised of the following: allocated portions of Vectren's deferred compensation and share-based compensation $33 million, asset retirement obligations $107 million, allocated portions of Vectren's postretirement obligations totaling $12 million, investment tax credits $2 million, environmental remediation $3 million, and other obligations totaling $6 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 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 working capital requirements has been cash generated from operations, which totaled $397.4 million in 2016, compared to $492.9 million in 2015 and $337.5 million in 2014. The $95.5 million decrease in operating cash flow in 2016 compared to 2015 driven primarily by changes in certain working capital accounts that reflect weather impacts, including reduced collections from customers, and increased unrecovered fuel and natural gas costs. In addition, tax payments to the Company's parent increased in 2016 compared to 2015.

The $155.4 million increase in cash flow in 2015 compared to 2014 is primarily driven by weather related impacts on working capital and reduced tax payments. The decrease in tax payments in 2015 reflects the full impact of bonus depreciation. 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 used in financing activities for the year ended December 31, 2016 was an inflow of $82.1 million while cash flow from financing activities for the years ended December 31, 2015 and 2014 was an outflow of $104.8 million and an inflow of $23.9 million, respectively. Financing activity reflects the Company’s utilization of the long-term capital markets in the current low interest rate environment. During 2015 and 2014, financing activities reflect the issuance of debt for the purposes of refinancing maturing debt and paying down short term borrowings. The Company’s operating cash flow funded 65 percent of capital expenditures and dividends in 2016, 97 percent of capital expenditures and dividends in 2015, and 73 percent of capital expenditures and dividends 2014. Recently completed long-term financing transactions are more fully described below.

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 and Indiana Gas Debt Transactions

On December 15, 2015, the Company 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.

A portion of the proceeds received from this issuance was 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, and (ii)$5 and $10 million of 6.69 percent Indiana Gas senior unsecured notes that matured on December 21, 2015 and December 29, 2015, respectively.

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.

Investing Cash Flow
Cash flow required for investing activities was $476.3 million in 2016, $401.2 million in 2015, and $350.7 million in 2014. The primary use of cash in all years reflects expenditures for utility plant. The increase in capital expenditures over the years presented is attributable to greater expenditures for gas infrastructure improvement projects and environmental compliance.

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; 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; and higher operating expenses.
- 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.
- 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 performance of projects undertaken by Vectren's nonutility businesses, specifically Vectren's infrastructure services businesses.

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's parent 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.

46

Commodity Price Risk

Regulated Operations

The Company has 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 15 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 $95 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 both 2016 and 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. 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 Utility Holdings, Inc.’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, cash flows, and common shareholder's 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 Shareholder and Board of Directors of Vectren Utility Holdings, Inc.:

We have audited the accompanying consolidated balance sheets of Vectren Utility Holdings, Inc. and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of income, common shareholder's 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, 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 Utility Holdings, Inc. 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, present fairly in all material respects the information set forth therein.

/s/ DELOITTE & TOUCHE LLP
Indianapolis, Indiana
March 9, 2017

VECTREN UTILITY HOLDINGS. INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(In millions)

	At December 31,	
	2016	2015
ASSETS		
Current Assets		
Cash & cash equivalents	$9.4	$6.2
Accounts receivable - less reserves of $4.1 & $3.0, respectively	102.6	92.3
Accrued unbilled revenues	112.0	85.7
Inventories	119.0	125.3
Recoverable fuel & natural gas costs	29.9	—
Prepayments & other current assets	38.6	49.0
Total current assets	411.5	358.5
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	0.2	0.2
Other investments	21.3	20.1
Nonutility plant - net	164.8	149.7
Goodwill	205.0	205.0
Regulatory assets	206.2	152.1
Other assets	49.0	32.2
TOTAL ASSETS	$5,040.9	$4,592.7

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

VECTREN UTILITY HOLDINGS, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(In millions)

	At December 31,	
	2016	2015
LIABILITIES & SHAREHOLDER'S EQUITY		
Current Liabilities		
Accounts payable	$205.4	$168.5
Payables to other Vectren companies	25.4	25.7
Accrued liabilities	140.1	128.4
Short-term borrowings	194.4	14.5
Current maturities of long-term debt	49.1	13.0
Total current liabilities	614.4	350.1
Long-Term Debt - Net of Current Maturities	1,331.0	1,379.2
Deferred Credits & Other Liabilities		
Deferred income taxes	854.5	758.4
Regulatory liabilities	453.7	433.9
Deferred credits & other liabilities	163.3	135.9
Total deferred credits & other liabilities	1,471.5	1,328.2
Commitments & Contingencies (Notes 8-11)		
Common Shareholder's Equity		
Common stock (no par value)	831.2	799.9
Retained earnings	792.8	735.3
Total common shareholder's equity	1,624.0	1,535.2
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$5,040.9	$4,592.7

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

VECTREN UTILITY HOLDINGS, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
(In millions)

	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
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

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

VECTREN UTILITY HOLDINGS, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2016	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$173.6	$160.9	$148.4
Adjustments to reconcile net income to cash from operating activities:			
Depreciation & amortization	219.1	208.8	203.1
Deferred income taxes & investment tax credits	96.7	85.8	55.7
Expense portion of pension & postretirement benefit cost	4.0	4.8	4.7
Provision for uncollectible accounts	6.6	6.9	6.1
Other non-cash charges - net	3.5	7.0	3.2
Changes in working capital accounts:			
Accounts receivable, including to Vectren companies & accrued unbilled revenues	(48.8)	50.5	(15.8)
Inventories	6.3	(12.1)	(23.3)
Recoverable/refundable fuel & natural gas costs	(37.8)	15.2	(4.4)
Prepayments & other current assets	5.0	30.0	(34.4)
Accounts payable, including to Vectren companies & affiliated companies	23.9	(15.2)	7.5
Accrued liabilities	18.7	0.7	(2.2)
Cash to fund pension and postretirement plans	(15.0)	(19.6)	—
Changes in noncurrent assets	(46.5)	(23.7)	6.4
Changes in noncurrent liabilities	(11.9)	(7.1)	(17.5)
Net cash provided by operating activities	397.4	492.9	337.5
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from:			
Long-term debt, net of issuance costs	—	236.3	62.4
Additional capital contribution	31.3	6.2	6.0
Requirements for:			
Dividends to parent	(116.1)	(110.4)	(108.7)
Retirement of long-term debt	(13.0)	(95.0)	(63.6)
Net change in short-term borrowings	179.9	(141.9)	127.8
Net cash used in financing activities	82.1	(104.8)	23.9
CASH FLOWS FROM INVESTING ACTIVITIES			
Proceeds from other investing activities	15.3	3.9	0.3
Requirements for:			
Capital expenditures, excluding AFUDC equity	(496.6)	(399.2)	(351.0)
Changes in restricted cash	5.0	(5.9)	—
Net cash used in investing activities	(476.3)	(401.2)	(350.7)
Net change in cash & cash equivalents	3.2	(13.1)	10.7
Cash & cash equivalents at beginning of period	6.2	19.3	8.6
Cash & cash equivalents at end of period	$9.4	$6.2	$19.3

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

VECTREN UTILITY HOLDINGS, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY
(In millions)

	Common Stock	Retained Earnings	Total
Balance at January 1, 2014	$ 787.7	$ 645.1	$ 1,432.8
Net income		148.4	148.4
Common stock:			
Additional capital contribution	6.0		6.0
Dividends		(108.7)	(108.7)
Balance at December 31, 2014	793.7	684.8	1,478.5
Net income		160.9	160.9
Common stock:			
Additional capital contribution	6.2		6.2
Dividends		(110.4)	(110.4)
Balance at December 31, 2015	799.9	735.3	1,535.2
Net income		173.6	173.6
Common stock:			
Additional capital contribution	31.3		31.3
Dividends		(116.1)	(116.1)
Balance at December 31, 2016	$ 831.2	$ 792.8	$ 1,624.0

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

VECTREN UTILITY HOLDINGS, INC. AND SUBSIDIARY COMPANIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Nature of Operations

Vectren Utility Holdings, Inc. (the Company, Utility Holdings or VUHI), an Indiana corporation, was formed on March 31, 2000, to serve as the intermediate holding company for Vectren Corporation’s (Vectren or the Company's parent) three operating 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). Herein, 'the Company' may also refer to Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Inc. and/or Vectren Energy Delivery of Ohio, Inc. The Company also has other assets that provide information technology and other services to the three utilities. Vectren, an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana, and was organized on June 10, 1999. Both Vectren and the Company are holding companies as defined by the Energy Policy Act of 2005 (Energy Act).

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.

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 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.

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 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 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.

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 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.

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.

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.

Revenues
Revenues are recorded as products and services are delivered to customers. To more closely match revenues and expenses, the Company records revenues for all gas and electricity delivered to customers but not billed at the end of an accounting period in Accrued unbilled revenues. Substantially all revenue sources are subject to unbillled accruals.

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 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.

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’s operations consist of 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.

Fair Value Measurements
Certain assets and liabilities are valued and disclosed at fair value. 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.
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.

Earnings Per Share

Earnings per share are not presented as the Company's common stock is wholly owned by the Company's parent.

Other Significant Policies

Included elsewhere in these notes are significant accounting policies related to retirement plans and other postretirement benefits, intercompany allocations and income taxes (Note 5).

3. Utility & Nonutility Plant

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

	At and For the Year Ended 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	$120.5	$107.6
Land & buildings	37.6	35.0
All other	6.7	7.1
Nonutility plant - net	$164.8	$149.7

Nonutility plant is presented net of accumulated depreciation and amortization totaling $264.7 million and $248.0 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.

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:		
Net deferred income taxes	$(17.1)	$(16.9)
	(17.1)	(16.9)
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:		
Unamortized debt issue costs, reacquisition premiums & hedging proceeds	24.1	25.8
Indiana authorized trackers	64.2	42.6
Deferred coal costs	21.2	28.3
Ohio authorized trackers	22.2	17.6
Other base rate recoveries	—	0.1
	131.7	114.4
Total regulatory assets	$206.2	$152.1

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 future recovery is probable.

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. Transactions with Other Vectren Companies and Affiliates

Vectren Infrastructure Services Corporation (VISCO)

VISCO, a wholly owned subsidiary of the Company's parent, provides underground pipeline construction and repair services. VISCO's customers include the Company's utilities and fees incurred by the Company totaled $117.8 million in 2016, $109.5 million in 2015, and $94.0 million in 2014. Amounts owed to VISCO at December 31, 2016 and 2015 are included in Payables to other Vectren companies.

Vectren Fuels, Inc.
On August 29, 2014, the Company's parent closed on a transaction to sell its wholly-owned coal mining subsidiary, Vectren Fuels, Inc. (Vectren Fuels), to Sunrise Coal, LLC (Sunrise), an Indiana-based wholly-owned subsidiary of Hallador Energy Company. Prior to the sale date, SIGECO purchased coal used for electric generation from Vectren Fuels. The amount purchased for the year ended December 31, 2014 totaled $98.6 million. After the exit of the coal mining business by the Company's parent, Sunrise has assumed Vectren Fuels' supply contracts and has also negotiated new contracts for similar quality coal that will result in the Company purchasing most of its coal supply from Sunrise.

Support Services & Purchases
The Company's parent provides corporate and general and administrative services to the Company and allocates certain costs to the Company, including costs for share-based compensation and for pension and other postretirement benefits that are not directly charged to subsidiaries. These costs are allocated using various allocators, including number of employees, number of customers and/or the level of payroll, revenue contribution and capital expenditures. Allocations are at cost. The Company received corporate allocations totaling $57.6 million, $52.3 million, and $57.0 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Retirement Plans & Other Postretirement Benefits
At December 31, 2016, the Company's parent maintains three closed qualified defined benefit pension plans (Vectren Corporation Non-Bargaining Retirement Plan, The Indiana Gas Company, Inc. Bargaining Unit Retirement Plan, Pension Plan for Hourly Employees of Southern Indiana Gas and Electric Company), a nonqualified supplemental executive retirement plan (SERP), and a postretirement benefit plan. The defined benefit pension plans and postretirement benefit plan, which cover the Company's 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 Company's current and former employees comprise the vast majority of the participants and retirees covered by these plans.

The Company's parent satisfies the future funding requirements and the payment of benefits from general corporate assets and, as necessary, relies on the Company to support the funding of these obligations. Although the Company has no contractual funding obligation, the company contributed $15.0 million and $19.6 million to Vectren's defined benefit pension plans during 2016 and 2015, respectively. The combined funded status of the plans was approximately 92 percent at December 31, 2016 and 90 percent at December 31, 2015.

The Company's parent allocates the periodic cost of its retirement plans calculated pursuant to US GAAP to its subsidiaries. Periodic cost, comprised of service cost and interest on that service cost, is directly charged to the Company based on labor at each measurement date and that cost is charged to operating expense and capital projects, using labor charges as the allocation method. For the years ended December 31, 2016, 2015 and 2014, costs totaling $6.1 million, $7.0 million and $6.7 million, respectively, were directly charged to the Company. Other components of periodic costs (such as interest cost, asset returns, and amortizations) and the service cost related to Vectren Corporate operations are charged to subsidiaries through the allocation process discussed above. Any difference between funding requirements and allocated periodic costs is recognized as an asset or liability until reflected in periodic costs.

Neither plan assets nor the ending liability is allocated to individual subsidiaries since these assets and obligations are derived from corporate level decisions. The allocation methodology is consistent with FASB guidance related to "multiemployer" benefit accounting. As of December 31, 2016 and 2015, $12.2 million and $12.0 million, respectively, is included in Deferred credits & other liabilities and represents costs related to other postretirement benefits directly charged to the Company that is yet to be funded to the Company's parent. As impacted by increased funding of pension plans, at December 31, 2016 and 2015, the Company has $40.9 million, and $30.3 million, respectively, included in Other Assets representing defined benefit funding by the Company that is yet to be reflected in costs.

Share-Based Incentive Plans & Deferred Compensation Plans

The Company does not have share-based compensation plans separate from the Company's parent. The Company recognizes its allocated portion of expenses related to share-based incentive plans and deferred compensation plans in accordance with FASB guidance and to the extent these awards are expected to be settled in cash that liability is pushed down to the Company. As of December 31, 2016 and 2015, $42.3 million and $35.7 million, respectively, is included in Accrued liabilities and Deferred credits & other liabilities and represents obligations that are yet to be funded to the Company's parent.

Income Taxes

The Company does not file federal or state income tax returns separate from those filed by its parent, Vectren Corporation. The Company's parent files a consolidated U.S. federal income tax return, and Vectren and/or certain of its subsidiaries file income tax returns in various states. Pursuant to a tax sharing agreement and for financial reporting purposes, Vectren subsidiaries record income taxes on a separate company basis. The Company's allocated share of tax effects resulting from it being a part of this consolidated tax group are recorded at the parent company level. Current taxes payable/receivable are settled with the Company's parent in cash quarterly and after filing the consolidated federal and state income tax returns.

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.

The components of income tax expense and amortization of investment tax credits follow:

	Year Ended December 31,		
(In millions)	2016	2015	2014
Current:			
Federal	$(1.4)	$(1.9)	$16.6
State	4.2	4.2	10.9
Total current taxes	2.8	2.3	27.5
Deferred:			
Federal	93.5	81.7	57.8
State	3.7	4.6	(1.6)
Total deferred taxes	97.2	86.3	56.2
Amortization of investment tax credits	(0.5)	(0.5)	(0.5)
Total income tax expense	$99.5	$88.1	$83.2

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 and local taxes-net of federal benefit	2.6	2.8	3.3
Amortization of investment tax credit	(0.2)	(0.2)	(0.2)
Domestic production deduction	(0.5)	(0.9)	(0.9)
Research and development credit	(0.8)	(2.0)	(0.3)
All other - net	0.3	0.7	(1.0)
Effective tax rate	36.4 %	35.4 %	35.9 %

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	$821.6	$752.6
Regulatory assets recoverable through future rates	17.6	31.6
Alternative minimum tax carryforward	(29.3)	(34.5)
Employee benefit obligations	10.2	7.2
Regulatory liabilities to be settled through future rates	(15.9)	(29.9)
Deferred fuel costs	25.9	14.2
Other – net	24.4	17.2
Net noncurrent deferred tax liability	$854.5	$758.4

At December 31, 2016 and 2015, investment tax credits totaling $1.6 million and $2.1 million, respectively, are included in Deferred credits & other liabilities. At December 31, 2016, the Company has alternative minimum tax carryforwards of $29.3 million, which do not expire.

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 $1.1 million and $0.7 million, respectively, at December 31, 2016 and 2015.

The Company's parent 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 Vectren's U.S. federal income tax returns for tax years through December 31, 2012. The State of Indiana, Vectren'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 for tax years 2009 and 2011, and 2019 for the tax year 2012.

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.

6. Borrowing Arrangements

Short-Term Borrowings

At December 31, 2016, the Company had $350 million of short-term borrowing capacity. As reduced by borrowings outstanding at December 31, 2016, approximately $156 million was available. This short-term credit facility is available through October 2019. The maximum limit of the facility remained unchanged. This facility is used to supplement working capital needs and also to fund capital investments and debt redemptions until financed on a long-term basis. The facility has a letter of credit limit of $100 million. As of December 31, 2016, there was no letters of credit outstanding under the facility. The Company has historically funded the short-term borrowing needs through the commercial paper market and expects to use the short-term borrowing facility in instances where the commercial paper market is not efficient.

Following is certain information regarding these short-term borrowing arrangements:

(In millions)	2016	2015	2014
Year End			
Balance Outstanding	$194.4	$14.5	$156.4
Weighted Average Interest Rate	1.05 %	0.55 %	0.50 %
Annual Average			
Balance Outstanding	$59.8	$53.8	$35.6
Weighted Average Interest Rate	0.71 %	0.38 %	0.34 %
Maximum Month End Balance Outstanding	$194.4	$121.5	$156.4

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

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
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
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
Total long-term debt outstanding	1,388.7	1,401.7
Current maturities of long-term debt	(49.1)	(13.0)
Debt issuance costs	(7.9)	(8.6)
Unamortized debt premium & discount - net	(0.7)	(0.9)
Total long-term debt-net	$1,331.0	$1,379.2

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. The reclassification had no material impact on the Company's financial condition, results of operations, or cash flows as a result of the adoption.

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 and Indiana Gas Debt Transactions
On December 15, 2015, the Company 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.

A portion of the proceeds received from this issuance was 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, and (ii) $5 and $10 million of 6.69 percent Indiana Gas senior unsecured notes that matured on December 21, 2015 and December 29, 2015, respectively.

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 years following 2016 (in millions) are $49.1 in 2017, $100.0 in 2018, $100.0 in 2020, $55.0 in 2021, and $1,076.0 thereafter. There are no maturities of long-term debt in 2019.

Debt Guarantees
The Company's currently outstanding long-term and short-term debt is jointly and severally guaranteed by SIGECO, Indiana Gas, and VEDO. The Company’s long-term debt and short-term debt outstanding at December 31, 2016, totaled $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.

7. Common Shareholder’s Equity

During the years ended December 31, 2016, 2015, and 2014, the Company has cumulatively received additional capital of $43.5 million from the Company's parent, of which $18.5 million was funded by new share issues from its dividend reinvestment plan and $25.0 million was received during 2016 from the nonutility operations of the Company's parent to fund the Company's capital expenditure program.

8. 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 $0.8 in 2017, $0.8 in 2018, $0.6 in 2019, $0.6 in 2020, $0.6 in 2021, and $1.6 thereafter. Total lease expense (in millions) was $1.1 in 2016, $0.8 in 2015, and $1.5 in 2014. Firm purchase commitments for utility plant total $4.4 million in 2017 and $1.5 million in 2018.

The Company’s regulated utilities have both firm and non-firm commitments to purchase natural gas, coal, and electricity as well as certain transportation and storage rights and certain contracts are firm commitments under five and twenty year arrangements. 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.

Legal and 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.

9. 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, the Company 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.

10. 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 the Company 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 Company's 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 requires 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.

On March 7, 2017, the Court of Appeals reversed the IURC's finding that the four year cap on lost margin recovery was arbitrary and the IURC failed to properly interpret the governing statute requiring that it review the utility's entire DSM proposal and approve or reject it as a whole, including the proposed lost margin recovery. On remand, the IURC must complete its review and can only reject the Company's lost margin recovery if found to be unreasonable. Once the Court's decision is final, the Company will again seek IURC approval of its energy efficiency plan.

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.

11. Environmental and Sustainability Matters

The Company initiated a corporate sustainability program in 2012 with the publication of the initial corporate sustainability report of the Company's parent. 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 a 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 sustainability policies and efforts, and in particular its policies and procedures designed to ensure compliance with applicable laws and regulations, are directly overseen by Vectren's Corporate Responsibility and Sustainability Committee, as well as vetted with Vectren's 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 is 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 CO2 produced from electric generation. The Company's share of total tons of CO2 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 CO2 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 CO2 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 CO2 emission rate, since 2005 through 2015, the Company has lowered its CO2 emission rate (as measured in lbs CO2/MWh) from 1,967 lbs CO2/MWh to 1,922 lbs CO2/MWh, for a reduction of 3 percent. The Company's CO2 emission rate of 1,922 lbs CO2/MWh is basically the same as Indiana's average CO2 emission rate of 1,923 lbs CO2/MWh. The Company plans to consider these reductions in CO2 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.

12. 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	$1,380.1	$1,495.3	$1,392.2	$1,495.0
Short-term borrowings	194.4	194.4	14.5	14.5
Cash & cash equivalents	9.4	9.4	6.2	6.2
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.

13. Segment Reporting

The Company's operations consist of 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 Company is comprised of three operating segments: Gas Utility Services, Electric Utility Services, and Other Operations. Net income is the measure of profitability used by management for all operations.

Information related to the Company's business segments is summarized below:

	Year Ended December 31,		
(In millions)	2016	2015	2014
Revenues			
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 revenues	$1,377.8	$1,394.5	$1,569.7
Profitability Measure - 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 net income	$173.6	$160.9	$148.4
Amounts Included in Profitability Measures			
Depreciation & Amortization			
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 depreciation & amortization	$219.1	$208.8	$203.1
Interest Expense			
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 interest expense	$69.7	$66.3	$66.6
Income Taxes			
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 income taxes	$99.5	$88.1	$83.2
Capital Expenditures			
Gas Utility Services	$358.5	$291.2	$245.9
Electric Utility Services	106.4	87.6	92.4
Other Operations	39.0	25.7	22.8
Non-cash costs & changes in accruals	(7.3)	(5.3)	(10.1)
Total capital expenditures	$496.6	$399.2	$351.0

	At December 31,		
(In millions)	2016	2015	2014
Assets			
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 assets	$5,040.9	$4,592.7	$4,409.3

14. 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
Materials & supplies	38.1	38.4
Coal & oil for electric generation - at average cost	42.6	45.0
Other	1.3	1.4
Total inventories	$119.0	$125.3

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 that carrying value at December 31, 2015.

Prepayments & other current assets in the Consolidated Balance Sheets consist of the following:

	At December 31,	
(In millions)	2016	2015
Prepaid gas delivery service	$26.4	$30.0
Prepaid taxes	8.0	3.9
Other prepayments & current assets	4.2	15.1
Total prepayments & other current assets	$38.6	$49.0

Other investments in the Consolidated Balance Sheets consist of the following:

	At December 31,	
(In millions)	2016	2015
Cash surrender value of life insurance policies	$20.4	$19.2
Restricted cash & other investments	0.9	0.9
Total other investments	$21.3	$20.1

Accrued liabilities in the Consolidated Balance Sheets consist of the following:

	At December 31,	
(In millions)	2016	2015

Refunds to customers & customer deposits	$49.4	$51.4
Accrued taxes	44.8	36.7
Accrued interest	16.4	16.3
Accrued salaries & other	29.5	24.0
Total accrued liabilities	$140.1	$128.4

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	$81.9	$54.6
Accretion	3.8	3.3
Liabilities incurred in current period	—	24.2
Changes in estimates, net of cash payments	20.9	(0.2)
Asset retirement obligation, December 31	$106.6	$81.9

Other – net in the Consolidated Statements of Income consists of the following:

	Year Ended December 31,		
(In millions)	2016	2015	2014
AFUDC - borrowed funds	$20.3	$16.3	$10.8
AFUDC - equity funds	2.2	2.6	3.2
Nonutility plant capitalized interest	1.0	0.4	0.6
Interest income	0.3	0.6	0.7
Other income	2.5	(1.2)	1.5
Total other – net	$26.3	$18.7	$16.8

Supplemental Cash Flow Information:

	Year Ended December 31,		
(In millions)	2016	2015	2014
Cash paid (received) for:			
Interest	$69.6	$66.2	$66.7
Income taxes	6.7	(23.1)	63.2

As of December 31, 2016 and