VECTREN CORP
Form 10-K
February 23, 2016

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, 2015
OR

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

For the transition period from __________________ to ________________________

Commission file number: 1-15467

VECTREN CORPORATION

(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

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

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

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

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

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of June 30, 2015, was $3,174,747,149.

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

Common Stock - Without Par Value	82,772,393	January 29, 2016
Class	Number of Shares	Date

Documents Incorporated by Reference

Certain information in the Company's definitive Proxy Statement for the 2016 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission pursuant to Regulation 14A, not later than 120 days after the end of the fiscal year, is incorporated by reference in Part III of this Form 10-K.

Definitions

AFUDC: allowance for funds used during construction

ASC: Accounting Standards Codification

ASU: Accounting Standards Update

BTU / MMBTU: British thermal units / millions of BTU

DOT: Department of Transportation

EPA: Environmental Protection Agency

FAC: Fuel Adjustment Clause

FASB: Financial Accounting Standards Board

FERC: Federal Energy Regulatory Commission

IDEM: Indiana Department of Environmental Management

IURC: Indiana Utility Regulatory Commission

IRC: Internal Revenue Code

kV: Kilovolt

GAAP: Generally Accepted Accounting Principles

GCA: Gas Cost Adjustment

MDth / MMDth: thousands / millions of dekatherms

MISO: Midcontinent Independent System Operator

MCF / BCF: thousands / billions of cubic feet

MW: megawatts

MWh / GWh: megawatt hours / thousands of megawatt hours (gigawatt hours)

NERC: North American Electric Reliability Corporation

OCC: Ohio Office of the Consumer Counselor

OUCC: Indiana Office of the Utility Consumer Counselor

PUCO: Public Utilities Commission of Ohio

Throughput: combined gas sales and gas transportation volumes

XBRL: eXtensible Business Reporting Language

Access to Information

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

Mailing Address:
One Vectren Square
Evansville, Indiana 47708

Phone Number:
(812) 491-4000

Investor Relations Contact:
M. Naveed Mughal
Treasurer and Vice President, Investor Relations
vvcir@vectren.com

Table of Contents

PART I

ITEM 1. BUSINESS

Description of the Business

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

Indiana Gas provides energy delivery services to approximately 580,000 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 314,000 natural gas customers located near Dayton in west central Ohio.

The Company, through Vectren Enterprises, Inc. (Enterprises), is involved in nonutility activities in two primary business areas: Infrastructure Services and Energy Services. Infrastructure Services provides underground pipeline construction and repair services. Energy Services provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects. Prior to August 29, 2014, the Company had activities in a coal mining business through Vectren Fuels, Inc. (Vectren Fuels). Results in the financial statements include the results of Coal Mining through the date of sale of August 29, 2014, when the Company exited the coal mining business. Further, prior to June 18, 2013, the Company had activities in its Energy Marketing business. Energy Marketing marketed and supplied natural gas and provided energy management services through ProLiance Holdings, LLC (ProLiance or ProLiance Holdings). In June 2013, ProLiance exited the gas marketing business through the disposition of certain of the net assets of its energy marketing subsidiary, ProLiance Energy, LLC (ProLiance Energy). Other minor operating results of the remaining ProLiance investment and Coal Mining are reflected in Other Businesses. Enterprises also has other legacy businesses that have investments in energy-related opportunities and services, among other investments. All of the above is collectively referred to as the Nonutility Group. Enterprises supports the Company's regulated utilities by providing infrastructure services.

Narrative Description of the Business

The Company segregates its operations into three groups: the Utility Group, the Nonutility Group, and Corporate and Other. At December 31, 2015, the Company had $5.4 billion in total assets, with $4.6 billion attributed to the Utility Group, and $0.8 billion attributed to the Nonutility Group. Net income for the year ended December 31, 2015, was $197.3 million, or $2.39 per share of common stock, with net income of $160.9 million attributed to the Utility Group, $36.3 million attributed to the Nonutility Group, and $0.1 million attributed to Corporate and Other. Net income for the year ended December 31, 2014, was $166.9 million, or $2.02 per share of common stock. For further information regarding the activities and assets of operating segments within these Groups, refer to Note 22 in the Company's

Consolidated Financial Statements included in Item 8. Following is a more detailed description of the Utility Group and Nonutility Group.

Utility Group

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

Gas Utility Services

At December 31, 2015, the Company supplied natural gas service to approximately 1,016,900 Indiana and Ohio customers, including 929,600 residential, 85,600 commercial, and 1,700 industrial and other contract customers. Average gas utility customers served were approximately 1,004,800 in 2015; 998,200 in 2014; and 992,100 in 2013.

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, aluminum products, polycarbonate resin (Lexan®) and plastic products; gypsum products; electrical equipment, metal specialties, glass and steel finishing; pharmaceutical and nutritional products; gasoline and oil products; ethanol; and coal mining. The largest Indiana communities served are Evansville, Bloomington, Terre Haute, suburban areas surrounding Indianapolis and Indiana counties near Louisville, Kentucky. The largest community served outside of Indiana is Dayton, Ohio.

Revenues

The Company receives gas revenues by selling gas directly to customers at approved rates or by transporting gas through its pipelines at approved rates to customers that have purchased gas directly from other producers, brokers, or marketers. Total throughput was 230.2 MMDth for the year ended December 31, 2015. Gas sold and transported to residential and commercial customers was 104.9 MMDth representing 46 percent of throughput. Gas transported or sold to industrial and other contract customers was 125.3 MMDth representing 54 percent of throughput. Rates for transporting gas generally provide for the same margins earned by selling gas under applicable sales tariffs.

For the year ended December 31, 2015, gas utility revenues were $792.6 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.

Availability of Natural Gas

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

Natural Gas Purchasing Activity in Indiana

The Indiana utilities enter into short-term and long-term contracts with third party suppliers to purchase natural gas. Certain contracts are firm commitments under five and ten-year arrangements. Prior to June 18, 2013, the Company contracted with a wholly owned subsidiary of ProLiance Holdings, LLC. ProLiance is an unconsolidated, nonutility affiliate of the Company and Citizens Energy Group (Citizens). On June 18, 2013, ProLiance exited the natural gas marketing business through the disposition of certain net assets of its energy marketing business, ProLiance Energy, LLC (ProLiance Energy) (See the discussion of ProLiance in Note 7 in the Company's Consolidated Financial Statements included in Item 8). During 2015, the

Company, through its utility subsidiaries, purchased all of its gas supply from third parties and 78 percent is from a single third party.

Natural Gas Purchasing Activity in Ohio
On April 30, 2008, the PUCO issued an order which approved the first two phases of a three phase plan to exit the merchant function in the Company's Ohio service territory. As a result, substantially all of the Company's Ohio customers now purchase natural gas directly from retail gas marketers rather than from the Company.

The PUCO provided for an Exit Transition Cost rider, which allows the Company to recover costs associated with the first two phases of the transition process. Exiting the merchant function has not had a material impact on earnings or financial condition. It, however, has and will continue to reduce Gas utility revenues and have an equal and offsetting impact to Cost of gas sold as VEDO, for the most part, no longer purchases gas for resale.

Total Natural Gas Purchased Volumes
In 2015, Utility Holdings purchased 72.7 MMDth volumes of gas at an average cost of $3.96 per Dth inclusive of demand charges. The average cost of gas per Dth purchased for the previous four years was $5.42 in 2014, $4.60 in 2013, $4.47 in 2012, and $5.30 in 2011.

Electric Utility Services

At December 31, 2015, the Company supplied electric service to approximately 144,000 Indiana customers, including approximately 125,400 residential, 18,500 commercial, and 100 industrial and other customers. Average electric utility customers served were approximately 143,600 in 2015; 142,900 in 2014; and 142,300 in 2013.

The principal industries served include polycarbonate resin (Lexan®) and 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, 2015, retail electricity sales totaled 5,458.1 GWh, resulting in revenues of approximately $559.4 million. Residential customers accounted for 36 percent of 2015 revenues; commercial 27 percent; industrial 34 percent; and other 3 percent. In addition, in 2015 the Company sold 337.8 GWh through wholesale activities principally to the MISO. Wholesale revenues, including transmission-related revenue, totaled $42.2 million in 2015.

System Load

Total load for each of the years 2011 through 2015 at the time of the system summer peak, and the related reserve margin, is presented below in MW.

Date of summer peak load	7/29/2015	8/27/2014	8/30/2013	7/24/2012	7/21/2011
Total load at peak	1,088	1,095	1,102	1,259	1,220
Generating capability	1,248	1,298	1,298	1,298	1,298
Purchase supply	37	38	38	136	136
Interruptible contracts & direct load control	72	71	48	60	60
Total power supply capacity	1,357	1,407	1,384	1,494	1,494
Reserve margin at peak	25 %	22 %	25 %	19 %	22 %

The winter peak load for the 2014-2015 season of approximately 933 MW occurred on January 7, 2015. The prior year winter peak load for the 2013-2014 season was approximately 953 MW, occurring on January 6, 2014.

Generating Capability
Installed generating capability as of December 31, 2015, 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 2015 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 4,882 GWh in 2015. 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 2.5 million tons were purchased for generating electricity during 2015. This compares to 2.9 million tons and 1.9 million tons purchased in 2014 and 2013, respectively. The utility's coal inventory was approximately 800 thousand tons and 600 thousand tons at December 31, 2015 and 2014, respectively.

Coal Purchases
The average cost of coal per ton purchased and delivered for the last five years was $55.22 in 2015, $55.18 in 2014, $58.38 in 2013, $68.65 in 2012, and $75.04 in 2011. Entering 2014, SIGECO had in place staggered term coal contracts with Vectren Fuels and one other supplier to provide supply for its generating units. During 2014, SIGECO entered into separate negotiations with Vectren Fuels and Sunrise Coal to modify its existing contracts as well as enter into new long-term contracts in order to secure its supply of coal with specifications that support its compliance with the Mercury and Air Toxins Rule. Subsequent to the sale of Vectren Fuels to Sunrise Coal in August 2014, all such contracts have been assigned to Sunrise Coal. Approximately 90 percent of the coal purchased in 2015 was from Sunrise Coal.

Firm Purchase Supply
The Company, through SIGECO, has a 1.5 percent interest in the Ohio Valley Electric Corporation (OVEC). OVEC is owned by several electric utility companies, including SIGECO, and supplies power requirements to the United States Department of Energy's (DOE) uranium enrichment plant near Portsmouth, Ohio. The participating companies can receive from OVEC, and are obligated to pay for, any available power in excess of the DOE contract demand. At the present time, the DOE contract demand is essentially zero. The Company's 1.5 percent interest in OVEC makes available approximately 30 MW of capacity. The Company purchased approximately 144 GWh from OVEC in 2015.

In April 2008, the Company executed a capacity contract with Benton County Wind Farm, LLC to purchase as much as 30 MW from a wind farm located in Benton County, Indiana, with the approval of the IURC. The contract expires in 2029. In 2015, the Company purchased approximately 75 GWh under this contract.

In December 2009, the Company executed a 20 year power purchase agreement with Fowler Ridge II Wind Farm, LLC to purchase as much as 50 MW of energy from a wind farm located in Benton and Tippecanoe Counties in Indiana, with the approval of the IURC. In 2015, the Company purchased 144 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 that of 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 2015, in hours when purchases from the MISO were in excess of generation sold to the MISO, the net purchases were 732 GWh. During 2015, in hours when sales to the MISO were in excess of purchases from the MISO, the net sales were 338 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.

Competition

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

Regulatory and Environmental Matters

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

Nonutility Group

The Company is involved in nonutility activities in two primary business areas: Infrastructure Services and Energy Services. Prior to August 29, 2014, the Company had activities in its Coal Mining business and, prior to June 18, 2013, in its Energy Marketing business.

Infrastructure Services

Infrastructure Services provides underground pipeline construction and repair to utility infrastructure through its wholly owned subsidiaries Miller Pipeline, LLC (Miller or Miller Pipeline) and Minnesota Limited, LLC (Minnesota Limited). Infrastructure Services provides services to many utilities, including the Company’s utilities, as well as other industries. Infrastructure Services generated approximately $843 million in gross revenues for 2015, compared to $779 million in 2014 and $784 million in 2013.

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

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

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

Energy Services

Performance-based energy contracting operations and sustainable infrastructure, such as distributed generation and combined heat and power projects, are performed through Energy Systems Group, LLC (ESG), which is a wholly owned subsidiary of the Company. In 2014, the Company, through ESG, purchased the federal business unit of Chevron Energy Solutions (CES) (see Note 5 in the Company's Consolidated Financial Statements included in Item 8). ESG assists schools, hospitals, governmental facilities, and other private institutions with reducing energy and maintenance costs by upgrading their facilities with energy-efficient equipment. ESG is also involved in developing sustainable infrastructure projects, including projects to process landfill gas into usable natural gas and electricity. ESG's customer base is primarily located throughout the Midwest, Mid-Atlantic, Southern and Southwestern United States. ESG generated revenues of approximately $200 million in 2015, compared to $130 million in 2014 and $91 million in 2013. ESG's backlog of fixed price construction projects at December 31, 2015 was $226 million, compared to $144 million at December 31, 2014.

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

Coal Mining

Prior to August 29, 2014, Coal Mining owned, and through its contract miners, mined and sold coal to the Company's utility operations and to third parties through its wholly owned subsidiary, Vectren Fuels. On July 1, 2014, the Company announced that it had reached an agreement to sell its wholly owned coal mining subsidiary, Vectren Fuels, to Sunrise Coal, LLC (Sunrise Coal) an Indiana-based wholly owned subsidiary of Hallador Energy Company. Sunrise Coal owns and operates coal mines in the Illinois Basin. On August 29, 2014, the transaction closed. Prior to the sale of Vectren Fuels, Coal Mining generated revenues of approximately $234 million in 2014 and $293 million in 2013.

ProLiance

The Company has an investment in and loans to ProLiance Holdings, a nonutility affiliate of the Company and Citizens Energy Group. On June 18, 2013, ProLiance Holdings exited the natural gas marketing business through the disposition of certain of the net assets, along with the long-term pipeline and storage commitments, of its energy marketing business, ProLiance Energy, LLC to a subsidiary of Energy Transfer Partners, ETC Marketing, Ltd. ProLiance Energy provided services to a broad range of municipalities, utilities, industrial operations, schools, and healthcare institutions located throughout the Midwest and Southeast United States. ProLiance Energy's customers included, among others, the Company's Indiana utilities as well as Citizens' utilities. The Company's remaining investment in ProLiance relates primarily to an investment in LA Storage, LLC. Consistent with its ownership percentage, the Company is allocated 61 percent of ProLiance's profits and losses; however, governance and voting rights remain at 50 percent for each member; and therefore, the Company accounts for its investment in ProLiance using the equity method of accounting. Additional information regarding the investment in ProLiance is included in Note 7 in the Company's Consolidated Financial Statements included in Item 8.

Other Businesses

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

Personnel

As of December 31, 2015, the Company and its consolidated subsidiaries had approximately 5,600 employees. Of those employees, 700 are subject to collective bargaining arrangements negotiated by Utility Holdings and 3,000 are subject to collective bargaining arrangements negotiated by Infrastructure Services.

Utility Holdings

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.

In June 2013, the Company reached a three-year labor agreement with Local 702 of the International Brotherhood of Electrical Workers, ending June 30, 2016. This labor agreement relates to employees of SIGECO.

Infrastructure Services

The Company, through its Infrastructure Services subsidiaries, negotiates various trade agreements through contractor associations. The two primary associations are the Distribution Contractors Association (DCA) and the Pipeline Contractors Association (PLCA). These trade agreements are with a variety of construction unions including Laborer's International Union of North America, International Union of Operating Engineers, United Association of Journeymen and Apprentices of the Plumbing and Pipe Fitting Industry, and Teamsters. The trade agreements through the DCA have varying expiration dates in 2016, 2017 and 2020. The trade agreements through the PLCA expire at various times in 2017. In addition, these subsidiaries have various project agreements and small local agreements. These agreements expire upon completion of a specific project or on various dates throughout the year.

ITEM 1A. RISK FACTORS

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

Corporate Risks

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

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

Deterioration in general economic conditions may have adverse impacts.

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

Financial market volatility could have adverse impacts.

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

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

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

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

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

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

Utility Operating Risks

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

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

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

The utility industry has been undergoing structural change for several years, resulting in increasing competitive pressure faced by electric and gas utility companies. Increased competition, including those from cogeneration, private generation, solar, and other renewables opportunities for customers, may create greater risks to the stability of the Company’s earnings generally and may in the future reduce its earnings from retail electric and gas sales. In this regard, the deployment and commercialization of technologies, such as renewable energy sources and cogeneration facilities, 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 implemented this choice for its gas customers in Ohio and is currently in the second of the three phase process to exit the merchant function in its Ohio service territory. The state of Indiana has not adopted any regulation requiring gas choice in the Company’s Indiana service territories; however, the Company operates under approved tariffs permitting certain industrial and commercial large volume customers to choose their commodity supplier. The Company cannot provide any assurance that increased competition or other changes in legislation, regulation or policies will not have a material adverse effect on its business, financial condition or results of operations.

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

The Company’s electric utility sales are sensitive to variations in weather conditions. In this regard, many customers rely on electricity to heat 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. 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 gas sales.

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

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

Trends Toward Stricter Standards

With the trend toward stricter standards, greater regulation, more extensive permit requirements, and an increase in the number and types of assets operated that are subject to regulation, the Company's investment in infrastructure and the associated operating costs have increased and are expected to increase in the future. As examples of the trend toward stricter regulation, the EPA has passed regulations involving fly ash disposal, cooling tower intake facilities, wastewater discharges, and greenhouse gases and continues to implement increasingly more stringent air quality standards.

Pipeline Safety Considerations
The Company monitors and maintains its natural gas distribution system to ensure that natural gas is delivered in a safe, efficient, and reliable manner. The Company's natural gas utilities are currently engaged in replacement programs in both Indiana and Ohio, the primary purpose of which is preventive maintenance and continual renewal and improvement. The Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (Pipeline Safety Law) was signed into law on January 3, 2012. While some compliance costs remain uncertain, the Pipeline Safety Law resulted in further investment in pipeline inspections, and where necessary, additional investments in pipeline infrastructure; and therefore, result in both increased levels of operating expenses and capital expenditures associated with the Company's natural gas distribution businesses as evidenced by recent regulatory filings and resulting Commission Orders in Indiana and Ohio by 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 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 (NOx), mercury, and non-hazardous substances such as coal combustion residuals, among others. Environmental legislation/regulation also requires that facilities, sites, and other properties associated with the Company's operations be operated, maintained, abandoned, and reclaimed to the satisfaction of applicable regulatory authorities. The Company's current costs to comply with these laws and regulations are significant to its results of operations and financial condition. Moreover, these compliance costs could substantially change the nature of the Company's generation fleet.

Climate Change and Renewable Energy Considerations
The Company and the State of Indiana are subject to the requirements 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 plants and natural gas distribution businesses. 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 greenhouse gas (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. At this time compliance costs and other effects associated with reductions in GHG emissions or obtaining renewable energy sources remain uncertain.

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

confidential information. The ultimate effects, which are difficult to quantify with any certainty, are partially limited through insurance.

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

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

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

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

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

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

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

The Company’s electric generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses, and increased purchase power costs. Such operational risks can arise from circumstances such as facility shutdowns due to equipment failure or operator error; interruption of fuel supply or increased prices of fuel as contracts expire; disruptions in the delivery of electricity; inability to comply with regulatory or permit requirements; labor disputes; and natural disasters. A recent change in operation announced by Alcoa could impact the future operations of a 300 MW unit at the Warrick Power Plant that is jointly owned with Alcoa Generating Corporation (AGC) as tenants in common. See Note 3 to the Company's Consolidated Financial Statements included in Item 8 for additional information. Finally, 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.

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 that of 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, which is currently under review based on joint complaints filed against the MISO and various MISO transmission owners, including the Company. The FERC has yet to rule on the cases and the Company is currently unable to predict the outcome of the proceeding.

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

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

The Company's regulated operations have limited exposure to commodity price risk for transactions involving purchases and sales of natural gas, coal, and purchased power for the benefit of retail customers due to current state regulations, which, subject to compliance with those regulations, allow for recovery of the cost of such purchases through natural gas and fuel cost adjustment mechanisms. However, significant volatility in the price of natural gas, coal, or purchased power may cause existing customers to conserve or motivate them to switch to alternate sources of energy as well as cause new home developers, builders, and new customers to select alternative sources of energy. Decreases in volumes sold could reduce earnings. The decrease would be more significant in the absence of constructive regulatory orders, such as those authorizing revenue decoupling, lost margin recovery, and other innovative rate designs. A decline in new customers could impede growth in future earnings. In addition, during periods when commodity prices are higher than historical levels, working capital costs could increase due to higher carrying costs of inventories and cost recovery mechanisms, and customers may have trouble paying higher bills leading to increased bad debt expenses. Additionally, significant oil price fluctuations and their economic impact on the ability to continue shale gas drilling may impact the prices 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. In addition, the Company's customers, especially large commercial and industrial customers, may choose to employ various technological advances to develop alternative energy sources, such as the construction and development of wind power, solar technology, or electric cogeneration facilities. Increased conservation efforts and the utilization of technological advances to increase energy efficiency or to develop alternate energy sources could lead to a reduction in demand for the Company's energy products and services, which could have an adverse effect on its revenues and overall results of operations.

Nonutility Operating Risks

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

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

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

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

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

Specific to low oil prices, the current low oil price environment has increased the amount of competition in the transmission construction sector. This increase in competition is due to other contractors adjusting crews and work load where some large exploration projects are being canceled. A sustained low oil price environment could impact results of operations.

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

Energy Services results are dependent on a number of factors. The industry is competitive and many of the contracts are subject to a bidding process. Should Energy Services be unsuccessful in bidding contracts or lose certain federal licensing, results of operations could be impacted. Through competitive bidding, the volume of contracted work could vary significantly from year to year. Further, to the extent there are unanticipated cost increases in completion of the contracted work, the profit margin realized on any single project could be reduced. Changes in legislation and regulations impacting the industries in which the customers served by Energy Services operate could impact operating results. Other risks include, but are not limited to: the inability to source outside financing for projects; risks associated with projects owned or operated; failure to appropriately design, construct, or operate projects; and cancellation of projects by customers and/or reductions in the scope of the projects.

Other Corporate Operating Risks

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

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

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

Increased derivatives regulations could impact results.

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

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

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

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

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

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

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

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

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

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

Catastrophic events, such as terrorist attacks, acts of civil unrest, and acts of God, may adversely affect Vectren's facilities and operations 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. Additionally, an act against the Company's nonutility businesses could result in the Company being unable to provide utility infrastructure services or performance-based energy contracting services. In the event of a severe disruption resulting from such events, the Company has contingency plans and employs crisis management to respond and recover operations. Despite these measures, if such an occurrence were to occur, results of operations and financial condition could be materially adversely affected.

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

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

Workforce risks could affect Vectren's financial results.

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

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

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

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

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Gas Utility Services

Indiana Gas owns and operates four active gas storage fields located in Indiana covering 58,100 acres of land with an estimated ready delivery from storage capability of 5.6 BCF of gas with maximum peak day delivery capabilities of 155,500 MCF per day. Indiana Gas also owns and operates three propane 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 13,000 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 3,200 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 it 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, 2015, 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 the Brown Station; 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 currently in operation is 245 MW, and they are generally used only for reserve, peaking, or emergency purposes due to the higher per unit cost of generation. 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 1,027 circuit miles of 345Kv, 138Kv and 69Kv lines. The transmission system also includes 36 substations with an installed capacity of 4,828 megavolt amperes (Mva). The electric distribution system includes 4,550 circuit miles of lower voltage overhead lines and 418 trench miles of conduit containing 2,208 circuit miles of underground distribution cable. The distribution system also includes 91 distribution substations with an installed capacity of 1,987 Mva and 54,767 distribution transformers with an installed capacity of 2,347 Mva.

SIGECO owns utility property outside of Indiana approximating 24 miles of 138Kv and 345Kv electric transmission lines, which are included in the 1,027 circuit miles discussed above. These assets are located in Kentucky and interconnect with Louisville Gas and Electric Company's transmission system at Cloverport, Kentucky and with Big Rivers Electric Cooperative at Sebree, Kentucky.

Other Properties

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

Property Serving as Collateral

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

ITEM 3. LEGAL PROCEEDINGS

The Company is party to various legal proceedings and audits and reviews by taxing authorities and other government agencies arising in the normal course of business. In the opinion of management, there are no legal proceedings or other regulatory reviews or audits pending against the Company that are 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 relate 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 and the Company in federal district court requesting that a class be certified and for various relief including that the Combined Plan be reformed and benefits thereunder be recalculated. The Company denied the allegations set forth in the complaint and has moved to dismiss the claim.

The Company is unable to quantify any potential impact of the claims. The Company does not expect, however, the outcome would have a material adverse effect on the Company's liquidity, results of operations or financial condition.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

PART II

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

Market Data, Dividends Paid, and Holders of Record

The Company's common stock trades on the New York Stock Exchange under the symbol ''VVC.'' For each quarter in 2015 and 2014, the high and low sales prices for the Company's common stock as reported on the New York Stock Exchange and dividends paid are presented below.

		Cash Dividend	Common Stock Price Range High	Low
2015				
	First Quarter	$0.380	$49.47	$42.47
	Second Quarter	$0.380	$45.24	$38.41
	Third Quarter	$0.380	$43.08	$37.26
	Fourth Quarter	$0.400	$47.00	$39.98
2014				
	First Quarter	$0.360	$39.59	$34.60
	Second Quarter	$0.360	$42.52	$38.20
	Third Quarter	$0.360	$42.74	$35.11
	Fourth Quarter	$0.380	$48.28	$39.67

On November 5, 2015 the board of directors declared a dividend of $0.40 per share, payable on December 1, 2015, to common shareholders of record on November 16, 2015.

As of January 31, 2016, there were 8,217 registered shareholders of the Company's common stock.

Quarterly Share Purchases

Periodically, the Company purchases shares from the open market to satisfy share requirements associated with the Company's share-based compensation plans; however, no such open market purchases were made during the quarter ended December 31, 2015.

Dividend Policy

Common stock dividends are payable at the discretion of the Board of Directors, out of legally available funds. The Company's policy is to target a 60 percent payout; however, this percentage has varied and could continue to vary due to short-term earnings volatility. The Company has increased its dividend for 56 consecutive years. While the Company is under no contractual obligation to do so, it intends to continue to pay dividends and to increase the dividend annually. Nevertheless, should the Company's financial condition, operating results, capital requirements, or other relevant factors change, future dividend payments, and the amounts of these dividends, will be reassessed.

ITEM 6. SELECTED FINANCIAL DATA

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

	Year Ended December 31,				
(In millions, except per share data)	2015	2014	2013	2012	2011
Operating Data:					
Operating revenues	$2,434.7	$2,611.7	$2,491.2	$2,232.8	$2,325.2
Operating income	$361.8	$314.5	$333.6	$352.5	$370.0
Net income	$197.3	$166.9	$136.6	$159.0	$141.6
Weighted average common shares outstanding	82.7	82.5	82.3	82.0	81.8
Fully diluted common shares outstanding	82.7	82.5	82.4	82.1	81.8
Basic earnings per share on common stock	$2.39	$2.02	$1.66	$1.94	$1.73
Diluted earnings per share on common stock	$2.39	$2.02	$1.66	$1.94	$1.73
Dividends per share on common stock	$1.540	$1.460	$1.425	$1.405	$1.385
Balance Sheet Data:					
Total assets	$5,409.9	$5,146.0	$5,088.7	$5,089.1	$4,862.9
Long-term debt, net	$1,722.8	$1,407.3	$1,777.1	$1,553.4	$1,559.6
Common shareholders' equity	$1,683.8	$1,606.6	$1,554.3	$1,526.1	$1,465.5

Results include the loss on disposition and operating results of Coal Mining in 2014 and the loss on disposition and operating results attributable to the Company's investment in ProLiance in 2013. Total assets in all periods presented reflect the retrospective impacts of the adoption in 2015 of ASU 2015-17, Balance Sheet Classification of Deferred Taxes.

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

Executive Summary of Consolidated Results of Operations

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

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

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

Results for the year ended December 31, 2015 were earnings of $197.3 million, or $2.39 per share, compared to earnings of $166.9 million, or $2.02 per share for the year ended December 31, 2014 and $136.6 million, or $1.66 per share for the year ended December 31, 2013. Results include the operating results and the loss on the sale of Vectren Fuels, through the date of sale of August 29, 2014, when the Company exited the coal mining business. In June 2013, ProLiance Holdings, LLC (ProLiance or ProLiance Holdings) exited the gas marketing business through the disposition of certain net assets of its energy marketing subsidiary, ProLiance Energy, LLC (ProLiance Energy). In 2014, excluding the loss on the disposition and operating results attributable to Vectren Fuels, consolidated net income for the year was $188.0 million, or $2.28 per share. In 2013, excluding the impact of the loss on disposition and operating results attributable to the Company's investment in ProLiance, consolidated net income was $174.1 million, or $2.12 per share.

Losses Related to the Exit of the Coal Mining Business and Gas Marketing Business

On August 29, 2014, the Company sold its wholly owned coal mining subsidiary, Vectren Fuels, to Sunrise Coal, LLC (Sunrise Coal), an Indiana-based wholly owned subsidiary of Hallador Energy Company. Sunrise Coal owns and operates coal mines in the Illinois Basin. Results from the Coal Mining segment (Coal Mining) for the year ended December 31, 2014, inclusive of the loss on the sale, were a loss of $21.1 million, net of tax, compared to a loss of $16.0 million for the year ended December 31, 2013.

Through June 18, 2013, the Company recorded its share of losses related to the sale of certain assets of ProLiance's subsidiary, ProLiance Energy. In the Consolidated Statements of Income, the loss on the disposition of these assets was a $41.9 million impact to Equity in losses of unconsolidated affiliates, a $1.7 million charge to Operating expense, and an income tax benefit reflected in Income taxes of $16.8 million. More detailed information about ProLiance Energy's sale of certain assets is included in Note 7 to the Company's Consolidated Financial Statements included in Item 8. In addition to the losses associated with the sale of certain assets, the Company recorded its share of operating losses from ProLiance through June 18, 2013 totaling $10.7 million, net of tax. In total, the Company's share of ProLiance's results reflects a net loss of $37.5 million, net of tax, for the period January 1, 2013 through June

18, 2013. Subsequent to the sale and through December 31, 2013, there were minor charges related to the wind down of the ProLiance operations. This final true-up from the ProLiance sale and other minor operating results of the remaining ProLiance investments and remaining Coal Mining business are reflected in the Other Businesses segment.

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

Net income (loss) and earnings per share, excluding results from Coal Mining in 2014 and ProLiance in 2013, the years of disposition, in total and by group, for the years ended December 31, 2015, 2014, and 2013 follow:

	Year Ended December 31,		
(In millions, except per share data)	2015	2014	2013
Net income (loss)*	$197.3	$188.0	$174.1
Attributed to:			
Utility Group	$160.9	$148.4	$141.8
Nonutility Group*	36.3	39.1	33.0
Corporate & Other	0.1	0.5	(0.7)
Basic EPS*	$2.39	$2.28	$2.12
Attributed to:			
Utility Group	$1.95	$1.80	$1.72
Nonutility Group*	0.44	0.47	0.41
Corporate & Other	—	0.01	(0.01)

*Excludes Coal Mining results in 2014 and ProLiance results in 2013.

Utility Group

For the year ended December 31, 2015, the Utility Group earnings were $160.9 million, compared to $148.4 million in 2014 and $141.8 million in 2013. The improved results in 2015 compared to 2014 are largely driven by returns earned on the Indiana and Ohio infrastructure replacement programs, offset somewhat by a decrease in electric margin primarily due to the favorable impacts of weather in the fourth quarter of 2014. Decreases in operating expenses related to performance-based compensation and the timing of power plant maintenance costs also favorably impacted earnings, as did increased research and development tax credits for certain qualifying information technology assets. Results in 2014 compared to 2013 reflect increased gas and electric margins. However, these increased margins were partially offset by higher operating expenses related to an increase in performance-based compensation expense and gas system maintenance resulting from the harsh winter in the first part of 2014.

Gas utility services

The gas utility segment earned $64.4 million during the year ended December 31, 2015, compared to $57.0 million in 2014 and $55.7 million in 2013. The improved results in the periods presented are primarily due to increased returns on the Indiana and Ohio infrastructure replacement programs as the investment in those programs continues to increase. Increased earnings in 2015 also resulted from growth in small customer count and a decrease in performance-based compensation expense. These increases were somewhat offset by the unfavorable impacts of weather on the Company's Ohio business in 2015. The increased margin in 2014 compared to 2013 was partially offset by higher operating expenses from increased performance-based compensation expense and increased weather-related maintenance of the gas system during the first half of 2014.

Electric utility services

The electric operations earned $82.6 million during 2015, compared to $79.7 million in 2014 and $75.8 million in 2013. Results in 2014 reflected the favorable impact of weather on retail electric margin, which management estimated the after tax impact to be approximately $2.2 million compared to 2015. Lower wholesale margin due primarily to lower market pricing also reduced 2015 results when compared to 2014. Lower operating expenses in 2015 driven primarily by decreases in power plant maintenance costs and performance-based compensation, favorably impacted 2015 results. Improved 2014 results compared to 2013 were due primarily to the impact of weather on retail electric margin, which management estimates the after tax impact to be approximately $1.1 million favorable compared to 2013 as well as an increase in lost revenue recovery margin related to electric conservation programs, which had an after tax favorable impact of $2.3 million. These improved results were offset somewhat by higher operating costs, including higher performance-based compensation and the acceleration of power supply maintenance projects completed in 2014.

Other utility operations
In 2015, earnings from other utility operations were $13.9 million, compared to $11.7 million in 2014 and $10.3 million in 2013. An increase in earnings was driven by a lower effective income tax rate in 2015, from increased research and development tax credits for certain qualifying information technology assets. Approximately $3.5 million of this increase was related to research and development tax credits for prior periods as the Internal Revenue Service recently issued guidance that provided clarifications of internal-use software that qualifies for the credit. The revaluation of Utility Group deferred income taxes related to the sale of Vectren Fuels and the rate reduction from a change in the Indiana tax legislation passed in 2014, resulted in higher earnings in 2014 compared to 2013.

Nonutility Group
Reported results for the Nonutility Group were earnings of $36.3 million in 2015, $18.0 million in 2014 and a loss of $4.5 million in 2013. Excluding Coal Mining results in 2014 and ProLiance results in 2013, the respective years of disposition, the Nonutility Group earned $39.1 million in 2014, compared to earnings of $33.0 million in 2013. Results in 2015 reflect a decrease in earnings from Infrastructure Services as certain bid projects were not renewed in 2015 and lower margin work was completed. This was due to an increasingly competitive environment as other contractors work to adjust crews and work load in the current lower oil price environment. Offsetting part of this decrease in earnings is an increase in earnings from Energy Services from increased revenues and increased tax deductions associated with energy efficiency projects. Results in 2014 compared to 2013 were unfavorably impacted by decreased results from Infrastructure Services due to the inability of work crews to complete work as planned because of the adverse winter weather in the early and latter parts of 2014. Energy Services results in 2014 compared to 2013 reflect reduced tax deductions associated with energy efficiency projects as well as a gain of $8.9 million after tax due to the reversal of the contingent consideration liability associated with the April 1, 2014 acquisition of the federal business unit of Chevron Energy Solutions, which resulted from the failure to meet certain earn out thresholds. These non-recurring earnings at Energy Services were used to fund the Vectren Foundation, a 501(c)(3) charitable organization, in an amount totaling $14.0 million, or $9.1 million after tax, which is reflected in Other operating expenses in the consolidated financial statements. Results in 2013 reflect losses at Coal Mining of $16.0 million.

Dividends

Dividends declared for the year ended December 31, 2015 were $1.540 per share, compared to $1.460 per share in 2014 and $1.425 per share in 2013. In December 2015, the Company's board of directors increased its quarterly dividend to $0.400 per share from $0.380 per share. The increase marks the 56th consecutive year Vectren and predecessor companies have increased annual dividends paid.

Use of Non-GAAP Performance Measures and Per Share Measures

Results Excluding Coal Mining and ProLiance
This discussion and analysis contains non-GAAP financial measures that exclude the results related to Coal Mining in 2014 and ProLiance in 2013, the respective years of disposition.

Management uses consolidated net income, consolidated earnings per share, and Nonutility Group net income (loss), excluding the results from Coal Mining in 2014 and ProLiance in 2013, to evaluate its results. Coal Mining and ProLiance results that are excluded from the GAAP measures are inclusive of holding company costs (corporate allocations, interest and taxes). Management believes analyzing underlying and ongoing business trends is aided by the removal of Coal Mining and ProLiance results and the rationale for using such non-GAAP measures is that the Company has now exited the coal mining and gas marketing businesses. Management believes this presentation provides the best representation of the overall results of the ongoing operations.

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

Contribution to Vectren's basic EPS

Per share earnings contributions of the Utility Group, Nonutility Group excluding Coal Mining results in 2014 and ProLiance results in 2013, and Corporate and Other are presented and are non-GAAP measures. Such per share amounts are based on the earnings contribution of each group included in the Company's consolidated results divided by the Company's basic average shares outstanding during the period. The earnings per share of the groups do not represent a direct legal interest in the assets and liabilities allocated to the groups; instead they represent a direct equity interest in the Company's assets and liabilities as a whole. These non-GAAP measures are used by management to evaluate the performance of individual businesses. In addition, other items giving rise to period over period variances, such as weather, may be presented on an after tax and per share basis. These amounts are calculated at a statutory tax rate divided by the Company's basic average shares outstanding during the period. Accordingly, management believes these measures are useful to investors in understanding each business' contribution to consolidated earnings per share and in analyzing consolidated period to period changes and the potential for earnings per share contributions in future periods. Per share amounts of the Utility Group and the Nonutility Group are reconciled to the GAAP financial measure of basic EPS by combining the two. Any resulting differences are attributable to results from Corporate and Other operations. The non-GAAP financial measures disclosed by the Company should not be considered a substitute for, or superior to, financial measures calculated in accordance with GAAP, and the financial results calculated in accordance with GAAP.

The following table reconciles consolidated net income, consolidated basic EPS, and Nonutility Group net income (loss) to those results excluding Coal Mining results in 2014 and ProLiance results in 2013, the respective years of disposition.

	Twelve Months Ended December 31, 2014		
(In millions, except EPS)	GAAP Measure	Exclude Coal Mining Losses	Non-GAAP Measure
Consolidated			
Net Income	$166.9	$21.1	$188.0
Basic EPS	$2.02	$0.26	$2.28
Nonutility Group Net Income	$18.0	$21.1	$39.1

	Twelve Months Ended December 31, 2013		
(In millions, except EPS)	GAAP Measure	Exclude ProLiance Losses	Non-GAAP Measure
Consolidated			
Net Income	$136.6	$37.5	$174.1
Basic EPS	$1.66	$0.46	$2.12
Nonutility Group Net Income (Loss)	$(4.5)	$37.5	$33.0

Detailed Discussion of Results of Operations

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

Results of Operations of the Utility Group

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

	Year Ended December 31,		
(In millions, except per share data)	2015	2014	2013
OPERATING REVENUES			
Gas utility	$792.6	$944.6	$810.0
Electric utility	601.6	624.8	619.3
Other	0.3	0.3	0.3
Total operating revenues	1,394.5	1,569.7	1,429.6
OPERATING EXPENSES			
Cost of gas sold	305.4	468.7	358.1
Cost of fuel & purchased power	187.5	201.8	202.9
Other operating	339.1	354.5	333.4
Depreciation & amortization	208.8	203.1	196.4
Taxes other than income taxes	57.1	60.2	57.2
Total operating expenses	1,097.9	1,288.3	1,148.0
OPERATING INCOME	296.6	281.4	281.6
Other income - net	18.7	16.8	10.5
Interest expense	66.3	66.6	65.0
INCOME BEFORE INCOME TAXES	249.0	231.6	227.1
Income taxes	88.1	83.2	85.3
NET INCOME	$160.9	$148.4	$141.8
CONTRIBUTION TO VECTREN BASIC EPS	$1.95	$1.80	$1.72

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 support the investment in other capital projects, allowing the utility to defer the impacts of these investments until its next base rate case. The Company has received approval to implement these mechanisms in both states.

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

Tracked Operating Expenses

Gas costs and fuel costs incurred to serve Indiana customers are two of the Company's most significant operating expenses. Rates charged to natural gas customers in Indiana contain a gas cost adjustment clause. 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 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

Over the last eight years, regulatory orders establishing new base rates have been received by each utility. 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 its most recent base rate 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

28

ranging from 10.15 percent to 10.40 percent. The authorized returns reflect the impact of rate design strategies that have been authorized by these state commissions.

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

Utility Group Margin

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

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

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

	Year Ended December 31,		
(In millions)	2015	2014	2013
Gas utility revenues	$792.6	$944.6	$810.0
Cost of gas sold	305.4	468.7	358.1
Total gas utility margin	$487.2	$475.9	$451.9
Margin attributed to:			
Residential & commercial customers	$360.8	$347.4	$341.1
Industrial customers	61.4	59.3	58.0
Other	9.3	11.1	9.7
Regulatory expense recovery mechanisms	55.7	58.1	43.1
Total gas utility margin	$487.2	$475.9	$451.9
Sold & transported volumes in MMDth attributed to:			
Residential & commercial customers	104.9	122.6	111.9
Industrial customers	125.3	116.6	111.7
Total sold & transported volumes	230.2	239.2	223.6

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. With rate designs that substantially limit the impact of weather on margin, heating degree days that were 95 percent of normal in Ohio and 88 percent of normal in Indiana during 2015, compared to 110 percent of normal in Ohio and 107 percent of normal in Indiana during 2014, had only a slight unfavorable impact on small customer margin. However, warmer weather 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.

For the year ended December 31, 2014, gas utility margins increased $24.0 million compared to 2013. Heating degree days that were 110 percent of normal in Ohio and 107 percent of normal in Indiana during 2014, compared to 103 percent of normal in Ohio and 102 percent of normal in Indiana during 2013, had a slight favorable impact on small customer margin. Colder weather increased sold and transported volumes, which was the primary driver in the higher regulatory expense recovery margin and a corresponding increase in operating expenses. Regulatory expense recovery margin increased $15.0 million compared to 2013. Customer margin increased $3.8 million compared to 2013 from small customer growth and large customer usage. Additionally, margin was favorably impacted by $3.5 million from the return from infrastructure replacement programs, particularly in Ohio in 2014 compared to 2013.

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)	2015	2014	2013
Electric utility revenues	$601.6	$624.8	$619.3
Cost of fuel & purchased power	187.5	201.8	202.9
Total electric utility margin	$414.1	$423.0	$416.4
Margin attributed to:			
Residential & commercial customers	$258.6	$260.8	$255.8
Industrial customers	109.7	111.2	108.7
Other	4.5	5.5	4.8
Regulatory expense recovery mechanisms	9.6	11.6	10.5
Subtotal: retail	$382.4	$389.1	$379.8
Wholesale power & transmission system margin	31.7	33.9	36.6
Total electric utility margin	$414.1	$423.0	$416.4
Electric volumes sold in GWh attributed to:			
Residential & commercial customers	2,714.4	2,762.3	2,722.1
Industrial customers	2,721.5	2,804.6	2,735.2
Other customers	22.2	22.6	21.8
Total retail volumes sold	5,458.1	5,589.5	5,479.1

Retail
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, which are not protected by weather normalizing mechanisms, 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.

In 2014, Electric retail utility margins were $389.1 million for the year ended December 31, 2014 and, compared to 2013, increased by $9.3 million. As energy conservation initiatives continue, the Company's lost revenue recovery mechanism related to electric conservation programs contributed increased margin of $3.9 million compared to 2013. Electric results, which are not protected by weather normalizing mechanisms, experienced a $1.8 million increase from weather in small customer margin as heating degree days were 107 percent of normal in 2014 compared to 102 percent of normal in 2013 and cooling degree days were 104 percent of normal in 2014 compared to 103 percent of normal in 2013. Results also reflect increased large customer usage, which had a favorable margin impact of $2.0 million. Margin from regulatory expense recovery mechanisms increased $1.1 million driven primarily by a corresponding increase in operating expenses associated with MISO costs.

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 to be operational at the end of 2016 or early in 2017, in order to generate power to meet a significant portion of its ongoing power needs. Electric service is currently provided to SABIC by the Company under a long-term contract that expires in May of 2016. SABIC's historical peak electric usage has been approximately 120 megawatts (MW). The cogen facility is expected to provide approximately 80 MW of capacity. Therefore, the Company will continue to provide all of SABIC's power requirements above the approximate 80 MW capacity of the cogen, which is projected to be approximately 40 MW. The Company will also provide back-up power, when required.

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)	2015	2014	2013
MISO Transmission system margin	$25.5	$26.1	$29.4
MISO Off-system margin	6.2	7.8	7.2
Total wholesale margin	$31.7	$33.9	$36.6

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms, and other transmission system operations, totaled $25.5 million during 2015, compared to $26.1 million in 2014 and $29.4 million in 2013. Results in 2015 and 2014 reflect lower returns on transmission investments associated with pending FERC ROE complaints. To date, the Company has invested $157.7 million in qualifying projects. The net plant balance for these projects totaled $140.2 million at December 31, 2015. 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. Although the allowed return is currently being challenged as discussed below in Rate and Regulatory Matters, once placed into service, these projects earn a FERC approved equity rate of return of 12.38 percent on the net plant balance. Operating expenses are also recovered. The Company has established a reserve pending the outcome of these complaints. 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. The last segment of that project was placed into service in December 2012.

For the year ended December 31, 2015, margin from off-system sales was $6.2 million, compared to $7.8 million in 2014 and $7.2 million in 2013. 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 in 2015 compared to 2014 reflect lower market pricing due to low natural gas prices, net of sharing. Off-system sales were 337.8 GWh in 2015, compared to 651.1 GWh in 2014, and 514.4 GWh in 2013.

Utility Group Operating Expenses

Other Operating

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.

For the year ended December 31, 2014, Other operating expenses increased $21.1 million compared to 2013. Costs recovered directly in margin account for $12.4 million of the increase during 2014. Excluding these pass through costs, other operating expenses increased $8.7 million in 2014, compared to 2013, primarily from an increase in performance-based compensation expense of $5.5 million and increased expenses related to gas system maintenance of $4.3 million largely due to the harsh winter weather in the first part of 2014.

31

Depreciation & Amortization
For the year ended December 31, 2015, Depreciation and amortization expense was $208.8 million, compared to $203.1 million in 2014 and $196.4 million in 2013. Results in the periods presented reflect increased utility plant investments placed into service.

Taxes Other Than Income Taxes
Taxes other than income taxes decreased $3.1 million in 2015 compared to 2014 and increased $3.0 million in 2014 compared to 2013. The decrease in 2015 is primarily due to decreased gas costs and thus lower revenues and related revenue taxes. The increase in 2014 compared to 2013 was primarily due to higher revenue taxes associated with increased consumption and higher gas costs.

Other Income-Net
Other income-net reflects income of $18.7 million in 2015, compared to $16.8 million in 2014 and $10.5 million in 2013. Results include increased allowance for funds used during construction (AFUDC) of approximately $4.7 million in 2015 compared to 2014. These increases are partially offset by decreases in returns on assets that fund certain benefit plans. Results in 2014 also reflect increased AFUDC of $7.5 million in 2014 compared to 2013. 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, 2015, Utility Group federal and state income taxes were $88.1 million, compared to $83.2 million in 2014 and $85.3 million in 2013. While income taxes increased primarily due to increased income in 2015, the income tax rate in 2015 decreased from 2014 due to an increase in research and development tax credits. The decrease in income taxes in 2014 compared to 2013 was due to the revaluation of Utility Group deferred income taxes related to the sale of Vectren Fuels, Inc. in 2014. Additionally, 2015 and 2014 reflect increases in tax deductions for domestic production activity compared to 2013.

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 a 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.

In April 2011, Indiana Senate Bill 251 (Senate Bill 251) was signed into Indiana law. The law 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 Commission, 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.

In April 2013, Indiana Senate Bill 560 (Senate Bill 560) was signed into Indiana law. This legislation 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.

In June 2011, Ohio House Bill 95 (House Bill 95) was signed into law. Outside of a base rate proceeding, this legislation permits a natural gas utility to apply for recovery of much of its capital expenditure program. The 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 recognized in the Consolidated Statements of Income currently. The recording of post-in-service carrying costs and depreciation deferral is limited by individual qualifying projects to three years after being placed into service at SIGECO and four years after being placed into service at Indiana Gas. At December 31, 2015 and December 31, 2014, the Company has regulatory assets totaling \$19.9 million and \$16.4 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 filed pursuant to Senate Bill 251 and 560, discussed further below.

Requests for Recovery under Indiana Regulatory Mechanisms
On August 27, 2014, the IURC issued an Order (August 2014 Order) approving the Company’s seven-year capital infrastructure replacement and improvement 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 via a fixed monthly charge per residential customer.

On September 26, 2014, the OUCC filed an appeal of the IURC's finding that the remaining value of retired assets replaced during the infrastructure projects should not be netted against the cost being recovered in the tracking mechanism. In June 2015, the Indiana Court of Appeals issued an opinion in favor of the Company that affirmed the IURC's August 2014 Order approving the infrastructure plan.

On January 14, 2015, the IURC issued an Order approving the Company’s initial request for recovery of the revenue requirement through June 30, 2014 as part of its approved seven-year plan. Also, consistent with the guidelines set forth in the original August 2014 Order, the IURC approved the Company’s update to its seven-year plan, to reflect changes to project prioritization as a result of both additional risk modeling and changes to estimated project costs. On April 1, 2015, the Company filed its second request for recovery of the revenue requirement associated with capital investment and applicable operating costs through December 31, 2014. On June 1, 2015, the Company amended its case to delay the recovery of a portion of the investment associated with Senate Bill 560 made from July 2014 to December 2014, until its third filing when it committed to provide additional project detail for the later years of the plan. This commitment was as a result of an Indiana Court of Appeals decision regarding the approval of Northern Indiana Public Service Company's (NIPSCO) proposed electric Transmission, Distribution, and Storage Improvement Charge (TDSIC) plan, and challenges to TDSIC plans filed by other Indiana utilities.
On July 22, 2015, the IURC issued an Order, approving the recovery of these investments consistent with the Company's proposal, with modification, specifically to the rate of return applicable to the Senate Bill 251 compliance component. The IURC found that the overall rate of return to be applied to the investment in determining the revenue requirement is to be updated with each filing, reflecting 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 base rate case. This IURC interpretation of the overall rate of return to be used is the same as that already in place for the Senate Bill 560 component.

On October 1, 2015, the Company filed its third request for recovery of the revenue requirement associated with capital investment and applicable operating costs through June 30, 2015, including investment associated with Senate Bill 560 made

33

from July 2014 to December 2014 that had been delayed in the second request. The Company provided an update to its seven-year plan, as well as additional detail on the planned investments included in the plan. The updated plan reflects capital expenditures of approximately $1 billion, an increase of $100 million from the previous plan, of which $272 million has been spent as of December 31, 2015. The ability to include new projects as part of an updated Senate Bill 560 plan has been challenged in this case.

As of December 31, 2015, the Commission has approved project categories that encompass planned infrastructure investments during the plan term of approximately $800 million of the proposed $1 billion of capital spend. The remaining proposed amount is now pending approval in the third request for recovery. Pursuant to the process outlined in Senate Bill 560, the Company expects an order in early 2016.

At December 31, 2015 and December 31, 2014, the Company has regulatory assets totaling $28.6 million and $11.4 million, respectively, associated with the return on investment as well as the deferral of depreciation and other operating expenses.

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 and certain other infrastructure. 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. To date, the Company has made capital investments under this rider totaling $202.5 million. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $18.2 million and $13.1 million at December 31, 2015 and December 31, 2014, respectively. Due to the expiration of the initial five-year term for the DRR in early 2014, the Company filed a request in August 2013 to extend and expand the DRR. 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 other infrastructure investments. The Order limits the resulting DRR fixed charge per month for residential and small general service customers to specific graduated levels over the next five years. The Company's five-year capital expenditure plan related to these infrastructure investments for calendar years 2013 through 2017 totals approximately $200 million. 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; however, the plan is not expected to exceed those caps. In addition, the Order approved the Company's commitment that the DRR can only be further extended as part of a base rate case. On August 26, 2015, the Company received an Order approving its adjustment to the DRR for recovery of costs incurred through December 31, 2014.

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 near the expiration of the DRR. As such, the bill impact limits discussed below are not expected to be reached given the Company's capital expenditure plan during the remaining two-year time frame.

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 have 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. As of December 31, 2015, the Company's deferrals have not reached this bill impact cap. In addition, the Orders approved the Company's proposal that subsequent requests for accounting authority will be filed annually in April. The Company submitted its most recent annual filing on April 30, 2015, which covers the Company’s capital expenditure program through calendar year 2015. During 2015 and 2014, these approved capital expenditure programs under

House Bill 95 generated Other income associated with the debt-related post-in-service carrying costs totaling $6.4 million and $3.9 million, respectively. Deferral of deprecation and property tax expenses related to these programs in 2015 and 2014 totaled $5.4 million and $3.1 million, respectively.

Other Regulatory Matters

Indiana Gas GCA Cost Recovery Issue
On July 1, 2014, Indiana Gas filed its recurring quarterly Gas Cost Adjustment (GCA) mechanism, which included recovery of gas cost variances incurred for the period January through March 2014. In August 2014, the OUCC filed testimony opposing the recovery of approximately $3.9 million of natural gas commodity purchases incurred during this period on the basis that a gas cost incentive calculation had not been properly performed. The calculation at issue is performed by the Company's supply administrator. In the winter period at issue, a pipeline force majeure event caused the gas to be priced at a location that was impacted by the extreme winter temperatures. After further review, the OUCC modified its position in testimony filed on November 5, 2014, and suggested a reduced disallowance of $3 million. The IURC moved this specific issue to a sub-docket proceeding. On April 1, 2015, a stipulation and settlement agreement between the Company, the OUCC, and the Company's supply administrator was filed in this proceeding. The IURC issued an Order on June 10, 2015 which approved the stipulation and settlement agreement, which resulted in recovery of approximately $1.4 million of the disputed amount via the Company's GCA mechanism, with the remaining $1.6 million received from the gas supply administrator.

Indiana Gas & SIGECO Gas Decoupling Extension Filing
On September 9, 2015, the IURC issued an Order granting the extension of the current decoupling mechanism in place at both Indiana gas companies and recovery of conservation program costs through December 2019.

Electric Rate and Regulatory Matters

SIGECO Electric Environmental Compliance Filing
On January 28, 2015, the IURC issued an Order (January 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 mercury and air toxic standards (MATS) effective in 2015 and to address an outstanding Notice of Violation (NOV) from the EPA. As of December 31, 2015, approximately $30 million has been spent on equipment to control mercury in both air and water emissions, and $29 million to address the issues raised in the NOV proceeding on the increase in sulfur trioxide emissions. The total investment is estimated to be between $75 million and $85 million. The Order approved the Company's request for deferred accounting treatment, as supported by provisions under Indiana Senate Bill 29 (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 occurring in 2015 and 2016. As of December 31, 2015, the Company has approximately $2.7 million deferred related to depreciation, property tax, and operating expense, and $1.1 million deferred related to post-in-service carrying costs.

In March 2015, the Company was notified that certain parties had filed a Notice of Appeal with the Indiana Court of Appeals in response to the IURC's Order. In June 2015, Joint Appellants' Citizens Action Coalition of Indiana, Inc., Sierra Club, Inc., and Valley Watch, Inc. (the appellants) filed a brief which challenged the sufficiency of the findings in the IURC's January Order approving the Company's investments and proposed accounting treatment in terms of whether that Order made certain findings required by statute. On October 29, 2015, the Indiana Court of Appeals issued its opinion affirming the IURC's findings with regard to equipment required to comply with MATS and certain national pollutant discharge elimination system rules (approximately $35 million). The Court remanded the case back to the IURC so that it can make the findings required by statute with regard to equipment required by the NOV (approximately $40 million). On February 12, 2016, the appellants filed a petition to reopen the evidentiary record in the case in order to submit additional evidence. The Company has opposed the motion and believes the IURC already has a sufficient record in this case. As it pertains to the equipment requirement required by the NOV, given the Commission's previous approval of this project, the Company believes the Commission will make these findings and issue a new order in support of the project.

SIGECO Electric Demand Side Management (DSM) Program Filing

On August 31, 2011, the IURC issued an Order approving an initial three-year DSM plan in the SIGECO electric service territory that complied with the IURC's energy saving targets. Consistent with the Company's proposal, the Order approved, among other items, the following: 1) recovery of costs associated with implementing the DSM Plan; 2) the recovery of a performance incentive mechanism based on measured savings related to certain DSM programs; 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 year ended December 31, 2015, 2014, and 2013, the Company recognized electric utility revenue of $10.1 million, $8.7 million, and $5.0 million, respectively, associated with this approved lost margin recovery mechanism.

On March 28, 2014, Indiana Senate Bill 340 was signed into law. This legislation ended electric DSM programs on December 31, 2014 that had been conducted to meet the energy savings requirements established by the IURC in 2009. The legislation also allows for industrial customers to opt out of participating in energy efficiency programs. As of January 1, 2015, approximately 80 percent of the Company’s eligible industrial load has opted out of participation in the applicable energy efficiency programs. The Company filed a request for IURC approval of a new portfolio of DSM programs on May 29, 2014 to be offered in 2015. On October 15, 2014, the IURC issued an Order approving a Settlement between the OUCC and the Company regarding the new portfolio of DSM programs effective January 2015, and new programs were implemented during the first quarter of 2015.

On May 6, 2015, Indiana's governor signed Indiana Senate Bill 412 (Senate Bill 412) into law requiring electricity suppliers to submit energy efficiency plans to the IURC at least once every three years. Senate Bill 412 also supports 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. In September 2015, the Company received an Order to continue offering and recovering the associated cost of its 2015 programs until March 31, 2016. In October 2015, the OUCC and Citizens Action Coalition of Indiana filed testimony recommending the rejection of the Company’s plan, contending it was not reasonable under the terms of Senate Bill 412 due to the program design and the Company’s proposal to recover lost revenues and incentives associated with the measures. Vectren filed rebuttal testimony in October 2015 defending the plan’s compliance with Senate Bill 412. The Company expects an order in the first quarter of 2016.

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. The joint parties seek to reduce the 12.38 percent ROE used in the MISO transmission owners’ rates, including SIGECO’s formula transmission rates, to 9.15 percent, and to set a capital structure in which the equity component does not exceed 50 percent. A second customer complaint case was filed on February 11, 2015 as the maximum FERC-allowed refund period for the November 12, 2013 case ended February 11, 2015. As of December 31, 2015, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $140.2 million at December 31, 2015.

These joint complaints are similar to a complaint against the New England Transmission Owners (NETO) filed in September 2011, which requested that the 11.14 percent incentive return granted on qualifying investments in NETO be lowered. On October 16, 2014, the FERC issued an Order in the NETO case approving a 10.57 percent return on equity and a calculation methodology.

The FERC acknowledged that the pending complaint raised against the MISO transmission owners is reasonable and denied the portion of the complaint addressing the equity component of the capital structure. An initial decision from its administrative law judge was received on December 22, 2015, authorizing the transmission owners to collect a Base ROE of 10.32 percent from November 12, 2013 through February 11, 2015 (the “first refund period”). The FERC is expected to rule on the proposed order in late 2016. A procedural schedule has been established for the second customer complaint case, establishing a target date of June 30, 2016 for the initial decision.

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. Once the FERC sets a new ROE in the complaint case, this adder will be applied to that ROE, with retroactive billing to occur back to January 7, 2015.

The Company has established a reserve considering both the initial decision and the approved 50 basis points adder.

Warrick Unit 4
SIGECO and Alcoa Generating Corporation (AGC), a subsidiary of Alcoa, Inc. (Alcoa), own the 300 MW unit at the Warrick Power Plant (Warrick Unit 4) as tenants in common. SIGECO's proportionate cost of the unit is included in rate base. In January 2016, Alcoa announced plans to close its smelter operations by the end of the first quarter 2016. 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 their generation, anticipating that more will be known toward the end of 2016.

Environmental Matters

The Company's utility operations and properties are subject to extensive environmental regulation pursuant to a variety of federal, state and municipal laws and regulations. These environmental regulations impose, among other things, restrictions, liabilities, and obligations in connection with the storage, transportation, treatment, and disposal of hazardous substances and limit airborne emissions from electric generating facilities including particulate matter, sulfur dioxide (SO_2), 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.

With the trend toward stricter standards, greater regulation, and more extensive permit requirements, the Company's investment in compliant infrastructure, and the associated operating costs have increased and are expected to increase in the future. Similar to the costs associated with federal mandates in the Pipeline Safety Law, Indiana Senate Bill 251 (Senate Bill 251) is also applicable to federal environmental mandates impacting SIGECO's electric operations.

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 back to the appellate court for further proceedings consistent with the opinion. MATS compliance was required to commence April 16, 2015, and the Company continues to operate in full compliance with the MATS rule. On December 15, 2015, the appellate court agreed to keep the current MATS rule in place while the agency completes the supplemental cost analysis ordered by the Court.

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 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 regarding SO_3 emissions from the EPA. The total investment is estimated to be between $75 million and $85 million, roughly half of which has been spent to control mercury in both air and water emissions, and the remaining investment has been made to address the issues raised in the NOV.

In March 2015, the Company was notified that certain parties had filed a Notice of Appeal with the Indiana Court of Appeals in response to the IURC's Order. In June 2015, Joint Appellants’ Citizens Action Coalition of Indiana, Inc., Sierra Club, Inc., and Valley Watch, Inc. (the appellants) filed a brief which challenged the sufficiency of the findings in the IURC's January Order approving the Company’s investments and proposed accounting treatment in terms of whether that Order made certain findings required by statute. On October 29, 2015, the Indiana Court of Appeals issued its opinion affirming the IURC’s findings with regard to equipment required to comply with MATS and certain national pollutant discharge elimination system rules (approximately $35 million). The Court remanded the case back to the IURC so that it can make the findings required by statute with regard to equipment required by the NOV (approximately $40 million). On February 12, 2016, the appellants filed a petition to reopen the evidentiary record in the case in order to submit additional evidence. The Company has opposed the motion and believes the IURC already has a sufficient record in this case. As it pertains to the equipment requirement required by the NOV, given the Commission’s previous approval of this project, the Company believes the Commission will make these findings and issue a new order in support of the project.

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. The EPA is expected to make final determinations as to whether a region is in attainment for the new NAAQS in 2018 based upon monitoring data from 2014-2016. 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.

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, in which 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 is currently working with the state of Indiana on voluntary measures that the Company may take 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.

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 Company will continue to reuse a majority of its ash. Legislation is currently being considered 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. Opening briefs were filed by those parties in December of 2015, with full briefing not expected to be complete until May 2016.

38

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, the Company prepared preliminary cost estimates to retire the ash ponds at the end of their useful lives based on interpretation of the available closure alternatives contemplated in the final rule that 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. At this time the Company does not believe that these rules are applicable to its Warrick generating unit, as this unit is part of a larger generating station that predominantly serves an adjacent industrial facility. The Company continues to refine the assumptions, engineering analyses and resulting cost estimates. Further analysis and the refinement of assumptions may result in estimated costs that could be significantly in excess of the current range of $35 million to $80 million.

At September 30, 2015, the Company recorded an approximate $25 million asset retirement obligation (ARO). The recorded ARO reflected the present value of the approximate $35 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.

Effluent Limitation Guidelines (ELGs)
Under the Clean Water Act, the EPA sets technology-based guidelines for water discharges from new and existing 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 within the 2018-2023 time frame. Current wastewater discharge permits for the Brown and Culley power plants expire in October and December 2016, respectively. The Company is working with the State on permit renewals which will include a compliance schedule for ELGs. In no event will compliance with the ELGs be required prior to November 2018. The ELGs work in tandem with the recently released 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.

Cooling Water Intake Structures
Section 316(b) of the Clean Water Act requires that 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. To comply, the Company believes that capital investments will likely be in the range of $4 million to $8 million.

Climate Change

Vectren is committed to responsible environmental stewardship and conservation efforts, and if a national climate change policy is implemented, 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 CO_2 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:

- Focusing the Company's mission statement and purpose on corporate sustainability and the need to help customers conserve and manage energy costs. Vectren's annual sustainability report received C level certification by the Global Reporting Initiative. This certification creates shared value, demonstrates the Company's commitment to sustainability and denotes transparency in operations;
- Implementing conservation initiatives in the Company's Indiana and Ohio gas utility service territories;
- Implementing conservation and demand side management initiatives in the electric service territory;
- 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;
- Reducing the Company's carbon footprint by measures such as utilizing hybrid vehicles and optimizing generation efficiencies by utilizing dense pack technology;
- Reducing methane emissions through continued replacement of bare steel and cast iron gas distribution pipeline and other actions such as implementing distribution integrity management measures, installing more excess flow and remote control valves on service lines and transmission systems, and enhanced damage prevention programs;
- Developing renewable energy and energy efficiency performance contracting projects through its Energy Services segment; and
- Helping energy producers install pipes that allow for more natural gas power generation and reduce gas flaring through its Infrastructure Services segment.

On August 3, 2015, the EPA released its final Clean Power Plan (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 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 it 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 the State of 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. The stay will remain in place while the lower court concludes its review, with oral arguments to be heard in June 2016 under the existing accelerated schedule. Among other things, the stay is anticipated to delay the requirement to submit a final SIP by the September 2016 deadline. Apart from the delay, the Court's action creates additional uncertainty as to the future of the rule and presents further challenges as the Company proceeds with its integrated resource planning process later this year.

In the event that 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

40

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 the State of Indiana will file a SIP has yet to be finally determined. Pending that determination, the electric utilities in Indiana are working with the state's designated agency to analyze various compliance options for consideration and possible integration into a state plan submittal.

Indiana is the 5th largest carbon emitter in the nation in tons of CO_2 produced from electric generation. In 2013, Indiana’s electric utilities generated 105.6 million tons of CO_2. The Company’s share of that total was 6.3 million, or less than 6 percent. From 2005 to 2014, the Company’s emissions of CO_2 have declined 27 percent (on a tonnage basis). These reductions have come from 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. 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 clean energy sources due to the long-term wind contracts and landfill gas investment. See further details on these clean energy sources in Item 1. With respect to CO_2 emission rate, since 2005 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 the State’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 when working 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 State of Indiana to assess the final rule and to develop a plan that is the least cost to its customers.

While the Company cannot reasonably estimate the total cost to comply with the CCR, ELG and CPP regulations at this time, the Company is exploring various compliance options ranging from continued compliance to retirement of units. The cost of compliance with these new regulations could be significant. The Company believes that such compliance costs would be considered a federally mandated cost of providing electricity, and therefore, should be recoverable from customers through Senate Bill 251 as referenced above, Senate Bill 29, which was used by the Company to recover its initial pollution control investments, or through other forms of rate recovery. These compliance alternatives, including the impact on customer rates, will be fully considered as part of the Company’s public integrated resource planning process to be conducted in 2016.

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 $43.4 million ($23.2 million at Indiana Gas and $20.2 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 to date approximately $14.8 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, 2015 and December 31, 2014, approximately $3.3 million and $3.6 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

Results of Operations of the Nonutility Group

The Nonutility Group operates in two primary business areas: Infrastructure Services and Energy Services. Infrastructure Services provides underground pipeline construction and repair services. Energy Services provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects. Prior to August 29, 2014, the Company had activities in its Coal Mining business. Results include the results of Vectren Fuels through the date of sale of August 29, 2014, when the Company exited the coal mining business through the sale of Vectren Fuels. Further, prior to June 18, 2013, the Company was involved in nonutility activities in its Energy Marketing business. Energy Marketing marketed and supplied natural gas and provided energy management services through ProLiance Holdings. In June 2013, ProLiance exited the gas marketing business through the disposition of certain of the net assets of its energy marketing subsidiary, ProLiance Energy. Other minor operating results of the remaining ProLiance investment and Coal Mining are reflected in Other Businesses. Enterprises has other legacy businesses that have investments in energy-related opportunities and services, among other investments. All of the above is collectively referred to as the Nonutility Group.

The Nonutility Group results were earnings of $36.3 million for the year ended December 31, 2015 and earnings of $18.0 million for the year ended December 31, 2014 and a loss of $4.5 million for the year ended December 31, 2013. Nonutility Group earnings, excluding the results from Coal Mining in 2014 and ProLiance in 2013, the years of disposition, for the years ended December 31, 2015, 2014, and 2013, follow. See page 28 for a reconciliation of Non-GAAP performance measures.

	Year Ended December 31,		
(In millions, except per share amounts)	2015	2014	2013
NET INCOME*	$36.3	$39.1	$33.0
CONTRIBUTION TO VECTREN BASIC EPS*	$0.44	$0.47	$0.41
NET INCOME (LOSS) ATTRIBUTED TO:			
Infrastructure Services	$29.7	$43.1	$49.0
Energy Services	7.3	(3.2)	1.0
Coal Mining*			(16.0)
Other Businesses	(0.7)	(0.8)	(1.0)

*Excludes Coal Mining Results in 2014 and ProLiance Results in 2013.

Infrastructure Services

Infrastructure Services provides underground pipeline construction and repair services through wholly owned subsidiaries Miller Pipeline, LLC (Miller or Miller Pipeline) and Minnesota Limited, LLC (Minnesota Limited). Inclusive of holding company costs, earnings from Infrastructure Services' operations for the year ended December 31, 2015 were $29.7 million compared to $43.1 million in 2014, and $49.0 million in 2013.

The distribution portion of the infrastructure operations reflected record revenue in 2015 as gas utilities across the country continue to make significant investment in their gas infrastructure systems. The lower than expected results from the transmission portion of the business were due largely to lower margin on awarded transmission contracts, as well as a significant transmission maintenance project not being renewed. That segment of transmission integrity work that was bid but not renewed is reflective of a more competitive environment. Other contractors are adjusting crews and work load in the current low oil price environment as some large gas and oil exploration projects have been canceled or delayed. Those contractors began competing more intensely in the maintenance market, resulting in fewer projects awarded to Infrastructure Services and lower margins on projects won. The strong and growing demand in the distribution services business and its very strong annual results helped offset some of the decline in transmission services' results. That growth trend in the distribution services business is expected to continue as utilities expand their infrastructure replacement programs. Finally, the fundamental business model related to the long cycle of repair and maintenance work remains unchanged as the demand remains high due to aging infrastructure and evolving safety and reliability regulations. Total Infrastructure Services gross revenues in 2015 were $843 million, compared to gross revenues of $779 million in 2014 and $784 million in 2013.

Results were lower in 2014 compared to 2013 due to the inability of work crews to complete their work as planned because of the adverse winter weather in the early and latter parts of 2014. These harsh weather conditions resulted in an estimated $3.0 million of reduced earnings in 2014 compared to 2013. Additionally, 2014 results reflect increased performance-based compensation expense, while results in 2013 reflect the favorable impacts of an 80-mile pipeline construction project.

Backlog represents the amount of gross revenue the Company expects to realize from work to be performed in the future on uncompleted contracts, including new contractual agreements on which work has not begun. Infrastructure Services operates primarily under two types of contracts, blanket contracts and bid contracts. Using blanket contracts, customers are not contractually committed to specific volumes of services, however the Company expects to be chosen to perform work needed by a customer in a given time frame. These contracts are typically awarded on an annual or multi-year basis. For blanket work, backlog represents an estimate of the amount of gross revenue that the Company expects to realize from work to be performed in the next twelve months on existing contracts or contracts the Company reasonably expects to be renewed or awarded based upon recent history or discussions with customers. Under bid contracts, customers are contractually committed to a specific service to be performed for a specific price, whether in total for a project or on a per unit basis. At December 31, 2015, Infrastructure Services had an estimated backlog of blanket contracts of $475 million and bid contracts of $190 million, for a total backlog of $665 million. The estimated backlog at December 31, 2014 was $500 million for blanket contracts and $125 million for bid contracts, for a total of $625 million. Estimated backlog at December 31, 2013 was $460 million for blanket contracts and $75 million for bid contracts, for a total of $535 million.

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

The long-term outlook for construction activity remains strong as utilities, municipalities and pipeline operators repair and replace aging natural gas and oil pipelines and related infrastructure and as pipeline operators construct new pipelines due to the continued significant demand for shale gas and oil infrastructure. The recent drop in oil prices has resulted in some production cuts that have been predominately related to the drilling of new wells. There are significant new pipe projects totaling over 14,000 miles already announced for 2016-2018 that are expected to absorb resources and equipment. The result should be a gradual decrease in competition for pipe maintenance work and an increase in margins. Pipelines are still being built for producing wells and, as such, the demand for this work is still strong. While the drop in oil prices could have greater impact if prices do not rebound, the mix of activity should improve and the long-term trends remain positive.

On May 6, 2015, Miller Pipeline acquired A&B Trenching Co., Inc. (A&B). The acquired company, North Carolina-based A&B, has been in operation since 1985 as a specialty contractor focusing on distribution pipeline construction and maintenance, directional boring and fabrication services. A&B employed about 200 people and serviced utility companies in three states in the southeastern U.S. Integration of A&B is occurring as planned.

Energy Services

Energy Services provides energy performance contracting and sustainable infrastructure, such as distributed generation, renewables, and combined heat and power projects, through its wholly owned subsidiary Energy Systems Group, LLC (ESG). Inclusive of holding company costs, Energy Services' operations were earnings of $7.3 million in 2015, compared to a loss of $3.2 million in 2014 and earnings of $1.0 million in 2013. Excluding the impact of the recently extended tax deductions, which are described below, Energy Services delivered a significant increase in operating earnings in 2015, returning to profitability at $1.2 million compared to operating losses of $6.9 million in 2014 and $5.4 million in 2013. Energy Services achieved record revenues of $200 million in 2015, which exceeded 2014's revenue of $130 million.

At December 31, 2015, the backlog of fixed price signed contracts has increased to $226 million, compared to $144 million on December 31, 2014 and $72 million on December 31, 2013. The Company's long-term view of the performance contracting and sustainable infrastructure opportunities remains strong as the national focus on energy conservation and security, renewable energy, and sustainability continues to grow given the expected rise in power prices across the country and customer focus on efficiency. Expected activity in the federal sector, as well as positive indications in the public sector and sustainable infrastructure business, is reflected in the strong backlog and sales funnel. Consistent with the national focus on energy conservation and efficiency and clean energy, in the past several years, there has been a provision in the tax code allowing for federal tax deductions related to energy efficiency savings achieved. ESG has reflected the benefit of those deductions in its results in the years where the deductions were available. In December 2015, the tax code section allowing those deductions was retroactively extended through 2016. The impact of these tax deductions on results, net of related expenses, was $6.1 million in 2015, $3.7 million in 2014, and $6.4 million in 2013.

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

On August 5, 2015, a significant Energy Savings Performance Contract (ESPC) was signed with the National Aeronautics and Space Administration’s (NASA) Johnson Space Center. The project value includes the cost of initial construction, commissioning, and start-up; long-term operations, maintenance, and equipment repair and replacement; and carrying costs. The objective of the project is to maximize energy cost savings associated with the project’s two energy conservation measures: Combined Heat and Power Plant; and Chilled Water Plant Improvements. The project will have a 22-month construction period. The contract includes an initial construction price of approximately $47 million, of which $35 million is included in backlog at December 31, 2015. The contract also includes a 22-year operations and maintenance agreement that will commence upon completion of construction. As is customary with performance contracts, guarantees of performance will be required.

Inclusive in the acquisition of FBU from Chevron on April 1, 2014, were several Indefinite Delivery / Indefinite Quantity contracts with federal government agencies including an ESPC with the U.S. Department of Energy and U.S. Army Corps of Engineers. On a periodic basis, the contracts are extended and/or subject to a recompete process. The recompete process for the U.S. Army Corps of Engineers contract was completed and awarded to ESG in May of 2015. The recompete process for the U.S. Department of Energy contract is currently in process, and management expects that the contract will be awarded to ESG. Anticipated completion of this process is expected in 2016.

Coal Mining

Prior to August 29, 2014, Coal Mining owned and, through its contract miners, mined and sold coal to the Company’s utility operations and to third parties through its wholly owned subsidiary, Vectren Fuels. On August 29, 2014, the Company sold Vectren Fuels. Results from Coal Mining for the year ended December 31, 2014, inclusive of the loss on sale, were a loss of $21.1 million compared to a loss of $16.0 million for the year ended December 31, 2013.

Other Businesses

ProLiance
The Company has an investment in ProLiance Holdings, LLC (ProLiance or ProLiance Holdings), a nonutility affiliate of the Company and Citizens Energy Group (Citizens). On June 18, 2013, ProLiance Holdings exited the natural gas marketing business through the disposition of certain of the net assets, along with the long-term pipeline and storage commitments, of its energy marketing business, ProLiance Energy, LLC (ProLiance Energy) to a subsidiary of Energy Transfer Partners, ETC Marketing, Ltd (ETC). ProLiance Energy's customers included, among others, the Company's Indiana utilities as well as Citizens' utilities. The Company's remaining investment in ProLiance relates primarily to an investment in LA Storage, LLC (LA Storage). Consistent with its ownership

percentage, the Company is allocated 61 percent of ProLiance's profits and losses; however, governance and voting rights remain at 50 percent for each member; and therefore, the Company accounts for its investment in ProLiance using the equity method of accounting.

As a result of ProLiance exiting the natural gas marketing business on June 18, 2013, the Company recorded its share of the loss on the disposition, termination of long-term pipeline and storage commitments, and related transaction and other costs totaling $43.6 million pre-tax, or $26.8 million net of tax, during the second quarter of 2013. For the year ended December 31, 2013, results related to the Company's share of ProLiance's results, which include financing costs, income taxes, and other holding company costs and inclusive of the loss associated with exiting the business, were a loss of $37.5 million. At December 31, 2015, ProLiance had approximately $48.8 million of capitalization remaining on its balance sheet, composed of $32.2 million in member's equity and $16.6 million in a note payable. The remaining capitalization is supported by its investment in LA Storage, formerly named Liberty Gas Storage, LLC of $36.4 million, one other midstream asset, $4.3 million in cash, and a small amount of other working capital. The Company's remaining investment in ProLiance at December 31, 2015 totals $29.8 million and is comprised of $19.7 million of equity and a $10.1 million note receivable.

LA Storage

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

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

The joint venture received a demand for arbitration from Williams Midstream Natural Gas Liquids, Inc. (Williams) in February 2011 related to a sublease agreement. Williams alleges the joint venture was negligent in its attempt to convert certain salt caverns to natural gas storage and seeks damages of $56.7 million. In August 2015, the joint venture and Williams agreed to settle the dispute. The Company's share of the settlement was not material to its results of operations or statement of financial condition.

Other Businesses

Within the Nonutility business segment, there are legacy investments involved in energy-related opportunities and services and other ventures. As of December 31, 2015, remaining legacy investments included in the Other Businesses portfolio total $7.0 million, of which $6.0 million are included in Other nonutility investments and $1.0 million are included in Investments in unconsolidated affiliates. During 2015, the Company sold its investment in a commercial real estate property as well as an interest in a leveraged lease for approximate book value. At December 31, 2015, the remaining investment relates to a debt security related to the sale of commercial real estate of $5.1 million and other investments of $1.9 million.

Other Businesses results were a loss of $0.7 million in 2015, compared to a loss of $0.8 million in 2014 and a loss of $1.0 million in 2013.

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 and IFRS. 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.

On July 9, 2015, the FASB approved a one year deferral that became effective through an Accounting Standard Update 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 evaluating the standard to determine application date, transition method, and impact the standard will have on the financial statements.

Financial Reporting of Discontinued Operations
In April 2014, the FASB issued new accounting guidance on reporting discontinued operations and disclosures of disposals of a company or entity. The guidance changes the criteria for reporting discontinued operations and provides for enhanced disclosures in this area. Under the new guidance, only disposals representing a strategic shift in operations should be presented as discontinued operations. Those strategic shifts should have a major effect on the organization's operations and financial results. Additionally, the new guidance requires expanded disclosures to provide more information about the assets, liabilities, income, and expenses of discontinued operations. The new guidance also requires disclosure of the pre-tax income attributable to a disposal of a significant part of an organization that does not qualify for discontinued operations reporting. This guidance is effective for fiscal years beginning on or after December 15, 2014, with early adoption permitted. The Company adopted this guidance on January 1, 2015. The Company did not early adopt this guidance in accounting for the sale of its Coal Mining assets. The adoption of this guidance had no impact on the Company's financial statements.

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 deduction 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. Early adoption is permitted. The new guidance will be applied retrospectively to each prior period presented. Upon adoption, the Company will revise its current presentation of debt issuance costs in the Consolidated Balance Sheets; however, the Company does not expect a material impact on its future financial condition, results of operations, or cash flows as a result of the adoption.

Balance Sheet Classification of Deferred Taxes
In November 2015, the FASB issued new accounting guidance on the presentation of deferred income taxes that requires deferred tax assets and liabilities, along with related valuation allowances, to be classified as noncurrent on the balance sheet. As a result, each tax jurisdiction will now only have one net noncurrent deferred tax asset or liability. The new guidance does not change the existing requirement that prohibits offsetting deferred tax liabilities from one jurisdiction against deferred tax assets of another jurisdiction. This guidance was early adopted for the year ended December 31, 2015, and has been applied retrospectively to all periods presented. The effect of this change on the December 31, 2015 and 2014 balance sheets is the reclassification of $15.3 million and $16.3 million in current deferred tax assets to long-term deferred tax liabilities, respectively. The amounts reclassified primarily represent the net of deferred tax assets arising from alternative minimum tax carryforwards and deferred tax liabilities arising from deferred fuels costs.

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

Critical Accounting Policies

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

Impairment Review of Investments and Long-Lived Assets

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

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

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

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

Goodwill & Intangible Assets

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

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

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

Pension & Other Postretirement Obligations

The Company estimates the expected return on plan assets, discount rate, rate of compensation increase, and future health care costs, among other inputs, and obtains actuarial estimates to assess the future potential liability and funding requirements of the Company's pension and postretirement plans. Detailed information about the assumptions the Company used to develop 2015 periodic benefit cost are included in Note 11 to the Company's Consolidated Financial Statements included in Item 8. To estimate the 2015 obligation and 2016 costs, the Company used the following weighted average assumptions: 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.

In October 2014, the Society of Actuaries (SOA) released updated mortality estimates that reflect increased life expectancy. The Company updated its mortality assumptions at December 31, 2014 to incorporate this increase in life expectancy. Accordingly, the Company updated its base mortality assumption to the SOA 2014 table as well as updated its projected mortality improvement. In October 2015, the SOA released updated projected mortality improvement that reflect additional years of data. The Company continues to use the SOA 2014 base table, but has updated projected mortality improvement to reflect inclusion of the additional data released in 2015. These changes are reflected in the Company's benefit obligation as of December 31, 2015. Future changes in health care costs, work force demographics, interest rates, asset values or plan changes could significantly affect the estimated cost of these future benefits. Management currently estimates the pension and postretirement cost to be approximately $5.5 million in 2016.

Management estimates that a 50 basis point increase in the discount rate used to estimate retirement costs generally decreases periodic benefit cost by approximately $2.0 million.

Regulation

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

Financial Condition

Within the Company’s consolidated group, Utility Holdings primarily funds the short-term and long-term financing needs of the Utility Group operations, and Vectren Capital Corp (Vectren Capital) funds short-term and long-term financing needs of the Nonutility Group and corporate operations. Vectren Corporation guarantees Vectren Capital’s debt, but does not guarantee Utility Holdings’ debt. Vectren Capital’s long-term debt, including current maturities outstanding at December 31, 2015 approximated $395 million. Vectren Capital had no short-term obligations outstanding at December 31, 2015. Utility Holdings’ outstanding long-term and short-term borrowing arrangements are jointly and severally guaranteed by its wholly owned subsidiaries and regulated utilities Indiana Gas, SIGECO, and VEDO. Utility Holdings’ long-term debt and short-term obligations outstanding at December 31, 2015 approximated $1 billion and $15 million, respectively. Additionally, prior to Utility Holdings’ formation, Indiana Gas and SIGECO funded their operations separately, and therefore, have long-term debt outstanding funded solely by their operations. SIGECO will also occasionally issue new tax-exempt debt to fund qualifying pollution control capital expenditures. Total Indiana Gas and SIGECO long-term debt, including current maturities, outstanding at December 31, 2015, was $401 million.

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

Vectren Corporation's corporate credit rating is A-, as rated by Standard and Poor's Ratings Services (Standard and Poor's). Moody's Investors Services (Moody's) does not provide a rating for Vectren Corporation. The credit ratings of the senior unsecured debt of Utility Holdings, SIGECO, and Indiana Gas, at December 31, 2015, were A-/A2 as rated by Standard and Poor's and Moody’s, respectively. The credit ratings on SIGECO's secured debt are A/Aa3. Utility Holdings’ commercial paper had a credit rating of A-2/P-1. The current outlook of both Moody’s and Standard and Poor’s is stable. A security rating is not a recommendation to buy, sell, or hold securities. The rating is subject to revision or withdrawal at any time, and each rating should be evaluated independently of any other rating. Standard and Poor’s and Moody’s lowest level investment grade rating is BBB- and Baa3, respectively.

The Company’s consolidated equity capitalization objective is 45-55 percent of long-term capitalization. This objective may have varied, and will vary, depending on particular business opportunities, capital spending requirements, execution of long-term financing plans, and seasonal factors that affect the Company’s operations. The Company's equity to long-term capitalization ratio was 48 percent and 50 percent as of December 31, 2015 and 2014, 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, 2015, 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 and cash flow generated from nonutility businesses. However, it has considered access to both short-term and long-term capital markets as a significant source of funding for capital requirements as the resources required for capital investment remain uncertain for a variety of factors including, but not limited to, expanded environmental regulations, growth of the regulated business, and growth of Infrastructure Services and Energy Services. These regulations may result in the need to raise additional capital in the coming years. To the extent that events beyond the Company's control create uncertainty in capital markets, cost of capital and ability to access capital markets may be affected. Refer to 'Risk Factors' in Item 1A for a summary of future considerations.

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

Consolidated Short-Term Borrowing Arrangements

At December 31, 2015, the Company had $600 million of short-term borrowing capacity, including $350 million for the Utility Group and $250 million for the wholly owned Nonutility Group and corporate operations. As reduced by borrowings currently outstanding, approximately $335 million was available for the Utility Group operations and $250 million was available for the wholly owned Nonutility Group and corporate operations. Both Vectren Capital’s and Utility Holdings’ short-term credit facilities were amended on October 31, 2014 to extend their maturity until October 31, 2019. These facilities are used to supplement working capital needs and also to fund capital investments and debt redemptions.

The Company has historically funded the short-term borrowing needs of Utility Holdings’ operations through the commercial paper market and has access to the Utility Holdings short-term borrowing facility in instances where commercial paper market is not efficient. Following is certain information regarding these short-term borrowing arrangements.

	Utility Group Borrowings			Nonutility Group Borrowings		
(In millions)	2015	2014	2013	2015	2014	2013
As of Year End						
Balance Outstanding	$14.5	$156.4	$28.6	$—	$—	$40.0

Weighted Average Interest Rate	0.55 %	0.50 %	0.29 %	N/A	NA	1.27 %
Annual Average Balance Outstanding	$53.8	$35.6	$119.6	$24.8	$34.5	$119.3
Weighted Average Interest Rate	0.38 %	0.34 %	0.34 %	1.33 %	1.29 %	1.35 %
Maximum Month End Balance Outstanding	$121.5	$156.4	$176.1	$69.1	$76.3	$173.8

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

New Share Issues

The Company may periodically issue new common shares to satisfy the dividend reinvestment plan, stock option plan and other employee benefit plan requirements. New issuances provided additional liquidity of $6.2 million in 2015, $6.1 million in 2014, and $6.9 million in 2013.

Potential Uses of Liquidity

Pension & Postretirement Funding Obligations

As of December 31, 2015, assets related to the Company's qualified pension plans were approximately 90 percent of the projected benefit obligation on a GAAP basis. As of the most recent valuation report date for the Company's qualified pension plans, assets were 122 percent of the target liability for ERISA purposes. The Company currently anticipates making contributions of $15 million to qualified pension plans in 2016.

Performance Guarantees & Product Warranties

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

Specific to ESG, in its role as a general contractor in the performance contracting industry, at December 31, 2015, there are 42 open surety bonds supporting future performance. The average face amount of these obligations is $9.8 million, and the largest obligation has a face amount of $51.0 million. The maximum exposure from these obligations is limited by the level of work already completed and guarantees issued to ESG by various subcontractors. At December 31, 2015, approximately 39 percent of work was completed on projects with open surety bonds. A significant portion of these open surety bonds will be released within one year. In instances where ESG operates facilities, project guarantees extend over a longer period. In addition to its performance obligations, ESG also warrants the functionality of certain installed infrastructure generally for one year and the associated energy savings over a specified number of years.

Based on a history of meeting performance obligations and installed products operating effectively, no liability or cost has been recognized for the periods presented.

Corporate Guarantees

The Company issues parent level guarantees to certain vendors and customers of its wholly owned subsidiaries. These guarantees do not represent incremental consolidated obligations; rather, they represent parental guarantees of subsidiary obligations to allow those subsidiaries the flexibility to conduct business without posting other forms of collateral. At December 31, 2015, parent level guarantees support a maximum of $185 million of ESG's performance contracting commitments, warranty obligations, project guarantees, and energy savings guarantees. Further, an energy facility operated by ESG and managed by Keenan Ft. Detrick Energy, LLC (Keenan), is governed by an operations agreement. All payment obligations to Keenan under this agreement are also guaranteed by the Company. The Company guarantee of the Keenan Ft. Detrick Energy operations agreement does not state a maximum guarantee. Due to the nature of work performed under this contract, the Company cannot estimate a maximum potential amount of future payments.

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

While there can be no assurance that the Company guarantee provisions will not be called upon, the Company believes that the likelihood of a material amount being triggered under any of these provisions is remote.

Planned Capital Expenditures & Investments

During 2015 capital expenditures and other investments approximated $477 million, of which approximately $398 million related to Utility Group expenditures. This compares to 2014 where consolidated capital expenditures and investments were approximately $448 million with $351 million attributed to the Utility Group and 2013 where consolidated capital expenditures and investments were approximately $411 million with $268 million attributed to the Utility Group. Planned Utility Group capital expenditures, including contractual purchase commitments, for the five-year period 2016 - 2020 are expected to total approximately (in millions): $480, $460, $430, $445, and $415, respectively. This plan contains the best estimate of the resources required for known regulatory compliance; however, many environmental and pipeline safety standards are subject to change in the near term. Such changes could materially impact planned capital expenditures.

Planned Nonutility Group capital expenditures and investments, including contractual purchase commitments, for the five-year period 2016 - 2020 are expected to total (in millions): $80, $85, $130, $90, and $95, respectively.

Contractual Obligations

The following is a summary of contractual obligations at December 31, 2015:

(In millions)	Total	2016	2017	2018	2019	2020	Thereafter
Long-term debt (1)	$1,795.8	$73.0	$75.0	$100.0	$60.0	$100.0	$1,387.8
Short-term debt	14.5	14.5	—	—	—	—	—
Long-term debt interest commitments	1,186.5	81.7	80.2	75.4	68.5	63.0	817.7
Plant and nonutility plant purchase commitments	4.6	3.5	1.1	—	—	—	—
Operating leases	30.4	8.6	5.7	3.8	2.1	1.9	8.3
Total (2)	$3,031.8	$181.3	$162.0	$179.2	$130.6	$164.9	$2,213.8

(1) The debt due in 2016 is comprised of debt issued by SIGECO and Vectren Capital.

(2) The Company has other long-term liabilities that total approximately $236 million. This amount is comprised of the following: pension obligations $51 million; postretirement obligations $39 million; deferred compensation and share-based compensation obligations $53 million; asset retirement obligations $82 million; investment tax credits $4 million; environmental remediation obligations $3 million; and other obligations including unrecognized tax benefits totaling $4 million. Based on the nature of these items, their expected settlement dates cannot be estimated.

The Company’s regulated utilities have both firm and non-firm commitments to purchase natural gas and electricity, as well as certain transportation and storage rights under five and ten-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. Because of the pass through nature of these costs, they have not been included in the listing of contractual obligations.

Comparison of Historical Sources & Uses of Liquidity

Operating Cash Flow

The Company's primary source of liquidity to fund capital requirements has been cash generated from operations, which totaled $505.2 million in 2015, compared to $488.2 million in 2014 and $587.0 million in 2013.

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

In 2014, operating cash flows decreased $98.8 million compared to 2013. This decrease was primarily due to higher coal inventory levels at December 31, 2014 primarily driven by weather variations in the year. Increased tax payments related to the sale of Vectren Fuels further contributed to this decrease in operating cash flow in 2014.

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 2015, 2014, and 2013. A significant portion of the Company's capital expenditures qualified for this bonus treatment.

Financing Cash Flow

Net cash flow required for financing activities was $47.3 million, $257.6 million, and $179.9 million for the years ended December 31, 2015, 2014, and 2013, respectively. Financing activity across all periods reflects the Company's utilization of the long-term capital markets in the current low interest rate environment. These lower rates have favorably impacted interest expense throughout the periods presented. In 2015, the Company issued $388 million in long-term debt. Current year issuances are partially offset by the retirement of $170 million in long-term debt, and an increased amount of short-term borrowings paid in the current period. In 2014, the Company retired approximately $124 million more in long-term debt compared to 2015 due principally to the use of proceeds from the sale of Vectren Fuels. The Company's operating cash flow funded over 83 percent of capital expenditures and dividends in 2015, over 85 percent in 2014, and 100 percent in 2013. Recently completed long-term financing transactions are more fully described below.

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

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

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

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

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

Vectren Capital Unsecured Note Retirement

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

SIGECO Debt Refund and Issuance
On September 24, 2014, SIGECO issued two new series of tax-exempt debt totaling $63.6 million. Proceeds from the issuance were used to retire three series of tax-exempt bonds aggregating $63.6 million at a redemption price of par plus accrued interest. The principal terms of the two new series of tax-exempt debt are: (i) $22.3 million sold in a public offering and bear

interest at 4.00 percent per annum, due September 1, 2044 and (ii) $41.3 million, due July 1, 2025, sold in a private placement at variable rates through September 2019.

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

Vectren Capital 2013 Term Loan
On August 6, 2013, Vectren Capital entered into a $100 million three-year term loan agreement. Loans under the term loan agreement bore interest at either a Eurodollar rate or base rate plus an additional margin which was based on the Company's credit rating. Interest periods were variable and could have ranged from seven days to six months. The proceeds from this debt transaction were used to repay short-term borrowings outstanding under Vectren Capital's credit facility. The loan agreement was guaranteed by Vectren Corporation and included customary representations, warranties, and covenants, including a leverage covenant consistent with leverage covenants contained in other Vectren Capital borrowing arrangements. The Company received net proceeds of approximately $100 million in August 2013 and repaid the loan in August of 2014.

SIGECO 2013 Debt Refund and Reissuance
During the second quarter of 2013, approximately $111 million of SIGECO's tax-exempt long-term debt was redeemed at par plus accrued interest. Approximately $62 million of tax-exempt long-term debt was reissued on April 26, 2013 at interest rates that are fixed to maturity, receiving proceeds, net of issuance costs, of approximately $60 million. The terms are $22.2 million at 4.00 percent per annum due 2038, and $39.6 million at 4.05 percent per annum due 2043.

The remaining approximately $49 million of the called debt was remarketed on August 13, 2013. The remarketed tax-exempt debt has a fixed interest rate of 1.95 percent per annum until September 13, 2017. SIGECO closed on this remarketing and received net proceeds of $48.3 million on August 28, 2013.

Utility Holdings 2013 Debt Call and Reissuance
On April 1, 2013, VUHI exercised a call option at par on Utility Holdings' $121.6 million 6.25 percent senior unsecured notes due in 2039. This debt was refinanced on June 5, 2013, with proceeds from a private placement note purchase agreement entered into on December 20, 2012 with a delayed draw feature. It provides for the following tranches of notes: (i) $45 million, 3.20 percent senior guaranteed notes, due June 5, 2028 and (ii) $80 million, 4.25 percent senior guaranteed notes, due June 5, 2043. Total proceeds received from these notes, net of issuance costs, were $44.8 million and $79.6 million, respectively. The notes are unconditionally guaranteed by Indiana Gas, SIGECO and VEDO.

On August 22, 2013, VUHI entered into a private placement note purchase agreement with a delayed draw feature, pursuant to which institutional investors agreed to purchase $150 million of senior guaranteed notes with a fixed interest rate of 3.72 percent per annum, due December 5, 2023. The notes were unconditionally guaranteed by Indiana Gas, SIGECO, and VEDO. On December 5, 2013, the Company received net proceeds of $149.1 million from the issuance of the senior guaranteed notes, which were used to refinance $100 million of 5.25 percent senior notes that matured August 1, 2013, for capital expenditures, and for general corporate purposes.

Mandatory Tenders
At December 31, 2015, 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 $469.6 million in 2015, $165.7 million in 2014, and $405.1 million in 2013. The primary use of cash in all periods presented reflect utility and non utility capital expenditures. Capital expenditures increased in 2015 as compared to 2014 by $28.6 million, and also increased in 2014 as compared to 2013 by $54.9 million. The increase in capital expenditures is attributable to greater expenditures for gas infrastructure improvement projects and environmental compliance. Cash flow required for investing activities in 2014 reflects the receipt of $311 million in proceeds from the sale of Vectren Fuels and reflects the acquisition of the federal business unit from Chevron Energy Solutions.

Forward-Looking Information

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

- Factors affecting utility operations such as 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, 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 our 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 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 rates, commodity prices, and monetary fluctuations.
- Economic conditions surrounding the current economic uncertainty, including increased potential for lower levels of economic activity; uncertainty regarding energy prices and the capital and commodity markets; volatile changes in the demand for natural gas, electricity, and other nonutility products and services; economic impacts of changes in business strategy on both gas and electric large customers; lower residential and commercial customer counts; higher operating expenses; and further reductions in the value of certain nonutility investments.

- Volatile natural gas and coal commodity prices and the potential impact on customer consumption, uncollectible accounts expense, unaccounted for gas and interest expense.
- Volatile oil prices and the potential impact on customer consumption and price of other fuel commodities.
- Direct or indirect effects on the Company’s business, financial condition, liquidity and results of operations resulting from changes in credit ratings, changes in interest rates, and/or changes in market perceptions of the utility industry and other energy-related industries.

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

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

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

Commodity Price Risk

Regulated Operations

The Company's regulated operations have limited exposure to commodity price risk for transactions involving purchases and sales of natural gas, coal and purchased power for the benefit of retail customers due to current state regulations, which subject to compliance with those regulations, allow for recovery of the cost of such purchases through natural gas and fuel cost adjustment mechanisms. Constructive regulatory orders, such as those authorizing lost margin recovery, other innovative rate designs, and recovery of unaccounted for gas and other gas related expenses, also mitigate the effect gas costs may have on the Company's financial condition. Although the Company's regulated operations are exposed to limited commodity price risk,

---

natural gas and coal prices have other effects on working capital requirements, interest costs, and some level of price-sensitivity in volumes sold or delivered. Indiana Gas and SIGECO hedge up to 50 percent of annual natural gas purchases for each Company utilizing a variety of terms for physical fixed-price purchases up to 10 years in duration. Indiana Gas also utilizes financial products, including call options. Such option contracts are generally short-term in nature and are insignificant in terms of value and volume at December 31, 2015 and 2014. 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, 2015 and 2014.

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, 2015, debt subject to interest rate volatility was approximately 3 percent, which was primarily due to the recent retirement of a significant amount of variable rate debt. 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 2015 and 2014, the weighted average combined borrowings under these arrangements approximated $120 million and $245 million, respectively. At December 31, 2015, combined borrowings under these arrangements were $56 million. As of December 31, 2014 combined borrowings under these arrangements were $198 million. Based upon average borrowing rates under these facilities during the years ended December 31, 2015 and 2014, an increase of 100 basis points (one percentage point) in the rates would have increased interest expense by approximately $1.2 million in 2015 and $2.4 million in 2014.

Other Risks

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

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MANAGEMENT'S RESPONSIBILITY FOR THE FINANCIAL STATEMENTS

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

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

These consolidated financial statements are also subject to an evaluation of internal control over financial reporting conducted under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer. Based on that evaluation, conducted under the framework in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, the Company concluded that its internal control over financial reporting was effective as of December 31, 2015. Management certified this in its Sarbanes Oxley Section 302 certifications, which are filed as exhibits to this 2015 Form 10-K.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Vectren Corporation:

We have audited the accompanying consolidated balance sheets of Vectren Corporation and subsidiaries (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, common shareholders' equity and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Vectren Corporation and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2015, based on the criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 23, 2016 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP
Indianapolis, Indiana
February 23, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Vectren Corporation:

We have audited the internal control over financial reporting of Vectren Corporation and subsidiaries (the "Company") as of December 31, 2015, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2015 of the Company and our report dated February 23, 2016 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ DELOITTE & TOUCHE LLP
Indianapolis, Indiana
February 23, 2016

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

	At December 31,	
	2015	2014
ASSETS		
Current Assets		
Cash & cash equivalents	$74.7	$86.4
Accounts receivable - less reserves of $5.6 & $6.0, respectively	227.5	196.0
Accrued unbilled revenues	142.5	164.8
Inventories	133.7	118.5
Recoverable fuel & natural gas costs	—	9.8
Prepayments & other current assets	81.0	94.6
Total current assets	659.4	670.1
Utility Plant		
Original cost	6,090.4	5,718.7
Less: accumulated depreciation & amortization	2,415.5	2,279.7
Net utility plant	3,674.9	3,439.0
Investments in unconsolidated affiliates	20.9	23.4
Other utility & corporate investments	31.2	37.2
Other nonutility investments	16.2	33.6
Nonutility plant - net	414.6	378.0
Goodwill	293.5	289.9
Regulatory assets	258.0	233.6
Other assets	41.2	41.2
TOTAL ASSETS	$5,409.9	$5,146.0

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

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

	At December 31,	
	2015	2014
LIABILITIES & SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$248.8	$248.9
Refundable fuel & natural gas costs	7.9	2.5
Accrued liabilities	183.6	184.9
Short-term borrowings	14.5	156.4
Current maturities of long-term debt	73.0	170.0
Total current liabilities	527.8	762.7
Long-term Debt - Net of Current Maturities	1,722.8	1,407.3
Deferred Income Taxes & Other Liabilities		
Deferred income taxes	805.4	724.9
Regulatory liabilities	433.9	410.3
Deferred credits & other liabilities	236.2	234.2
Total deferred credits & other liabilities	1,475.5	1,369.4
Commitments & Contingencies (Notes 7, 17-20)		
Common Shareholders' Equity		
Common stock (no par value) - issued & outstanding 82.8 & 82.6 shares, respectively	722.8	715.7
Retained earnings	962.2	892.2
Accumulated other comprehensive (loss)	(1.2)	(1.3)
Total common shareholders' equity	1,683.8	1,606.6
TOTAL LIABILITIES & SHAREHOLDERS' EQUITY	$5,409.9	$5,146.0

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

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

	Year Ended December 31,		
	2015	2014	2013
OPERATING REVENUES			
Gas utility	$792.6	$944.6	$810.0
Electric utility	601.6	624.8	619.3
Nonutility	1,040.5	1,042.3	1,061.9
Total operating revenues	2,434.7	2,611.7	2,491.2
OPERATING EXPENSES			
Cost of gas sold	305.4	468.7	358.1
Cost of fuel & purchased power	187.5	201.8	202.9
Cost of nonutility revenues	355.0	346.4	366.7
Other operating	909.2	943.4	891.6
Depreciation & amortization	256.3	273.4	277.8
Taxes other than income taxes	59.5	63.5	60.5
Total operating expenses	2,072.9	2,297.2	2,157.6
OPERATING INCOME	361.8	314.5	333.6
OTHER INCOME (EXPENSE)			
Equity in earnings (losses) of unconsolidated affiliates	(0.6)	0.5	(59.7)
Other income – net	20.3	19.7	17.7
Total other income (expense)	19.7	20.2	(42.0)
Interest expense	84.5	86.7	87.9
INCOME BEFORE INCOME TAXES	297.0	248.0	203.7
Income taxes	99.7	81.1	67.1
NET INCOME	$197.3	$166.9	$136.6
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING	82.7	82.5	82.3
DILUTED COMMON SHARES OUTSTANDING	82.7	82.5	82.4
EARNINGS PER SHARE OF COMMON STOCK:			
BASIC	$2.39	$2.02	$1.66
DILUTED	$2.39	$2.02	$1.66

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

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

	Year Ended December 31,		
	2015	2014	2013
NET INCOME	$197.3	$166.9	$136.6
Accumulated other comprehensive income (AOCI) of unconsolidated affiliates			
Net amount arising during the year before tax	—	—	4.6
Income taxes	—	—	(1.8)
AOCI of unconsolidated affiliates, net of tax	—	—	2.8
Pension & other benefits			
Amounts arising during the year before tax	1.2	(52.6)	61.4
Reclassifications to periodic cost before tax	6.9	3.4	9.1
Deferrals to regulatory assets	(8.0)	48.2	(69.1)
Income taxes	—	0.4	(0.6)
Pension & other benefits costs, net of tax	0.1	(0.6)	0.8
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX	0.1	(0.6)	3.6
TOTAL COMPREHENSIVE INCOME	$197.4	$166.3	$140.2

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

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

	Year Ended December 31,		
	2015	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$197.3	$166.9	$136.6
Adjustments to reconcile net income to cash from operating activities:			
Depreciation & amortization	256.3	273.4	277.8
Deferred income taxes & investment tax credits	80.4	37.9	43.3
Equity in (earnings) losses of unconsolidated affiliates	0.6	(0.5)	59.7
Provision for uncollectible accounts	8.1	7.3	6.8
Expense portion of pension & postretirement benefit cost	6.8	6.6	9.9
Other non-cash charges - net	6.7	5.8	5.8
Loss on sale of business (pretax)	—	41.8	—
Gain on revaluation of contingent consideration	—	(14.8)	—
Changes in working capital accounts:			
Accounts receivable & accrued unbilled revenues	(15.4)	11.8	1.5
Inventories	(15.2)	(22.5)	24.2
Recoverable/refundable fuel & natural gas costs	15.2	(4.4)	22.4
Prepayments & other current assets	20.3	(35.2)	12.8
Accounts payable, including to affiliated companies	(0.5)	20.2	6.8
Accrued liabilities	(0.9)	12.3	(1.2)
Unconsolidated affiliate dividends	1.3	—	1.1
Employer contributions to pension & postretirement plans	(26.5)	(5.1)	(13.7)
Changes in noncurrent assets	(23.2)	0.1	(2.1)
Changes in noncurrent liabilities	(6.1)	(13.4)	(4.7)
Net cash provided by operating activities	505.2	488.2	587.0
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from:			
Long-term debt, net of issuance costs	385.5	62.4	481.7
Dividend reinvestment plan & other common stock issuances	6.2	6.1	6.9
Requirements for:			
Dividends on common stock	(127.3)	(120.4)	(117.3)
Retirement of long-term debt	(170.0)	(293.6)	(338.9)
Other financing activities	0.2	0.1	(2.1)
Net change in short-term borrowings	(141.9)	87.8	(210.2)
Net cash used in financing activities	(47.3)	(257.6)	(179.9)
CASH FLOWS FROM INVESTING ACTIVITIES			
Proceeds from:			
Sale of business	—	311.2	—
Sale of assets and other collections	27.5	9.5	5.6
Requirements for:			
Capital expenditures, excluding AFUDC equity	(476.9)	(448.3)	(393.4)
Business acquisitions and other costs	(14.3)	(38.1)	—
Other investments	—	—	(17.3)
Changes in restricted cash	(5.9)	—	—
Net cash used in investing activities	(469.6)	(165.7)	(405.1)
Net change in cash & cash equivalents	(11.7)	64.9	2.0

Cash & cash equivalents at beginning of period	86.4	21.5	19.5
Cash & cash equivalents at end of period	$74.7	$86.4	$21.5

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

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

	Common Stock			Accumulated Other	
	Shares	Amount	Retained Earnings	Comprehensive Income (Loss)	Total
Balance at January 1, 2013	82.2	$700.5	$829.9	$(4.3)	$1,526.1
Net income			136.6		136.6
Other comprehensive income				3.6	3.6
Common stock:					
Issuance: option exercises & dividend reinvestment plan	0.2	6.9			6.9
Dividends ($1.425 per share)			(117.3)		(117.3)
Other		1.9	(3.5)		(1.6)
Balance at December 31, 2013	82.4	709.3	845.7	(0.7)	1,554.3
Net income			166.9		166.9
Other comprehensive income				(0.6)	(0.6)
Common stock:					
Issuance: option exercises & dividend reinvestment plan	0.2	6.1			6.1
Dividends ($1.460 per share)			(120.4)		(120.4)
Other		0.3			0.3
Balance at December 31, 2014	82.6	715.7	892.2	(1.3)	1,606.6
Net income			197.3		197.3
Other comprehensive income (loss)				0.1	0.1
Common stock:					
Issuance: option exercises & dividend reinvestment plan	0.2	6.2			6.2
Dividends ($1.540 per share)			(127.3)		(127.3)
Other		0.9			0.9
Balance at December 31, 2015	82.8	$722.8	$962.2	$(1.2)	$1,683.8

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

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Nature of Operations

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

Indiana Gas provides energy delivery services to approximately 580,000 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 314,000 natural gas customers located near Dayton in west central Ohio.

The Company, through Vectren Enterprises, Inc. (Enterprises), is involved in nonutility activities in two primary business areas: Infrastructure Services and Energy Services. Infrastructure Services provides underground pipeline construction and repair services. Energy Services provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects. Prior to August 29, 2014, the Company had activities in its Coal Mining business. Results in the financial statements include the results of Vectren Fuels, Inc. (Vectren Fuels) through the date of sale of August 29, 2014, when the Company exited the coal mining business. Further, prior to June 18, 2013, the Company had activities in its Energy Marketing business. Energy Marketing marketed and supplied natural gas and provided energy management services through ProLiance Holdings, LLC (ProLiance or ProLiance Holdings). In June 2013, ProLiance exited the gas marketing business through the disposition of certain net assets of its energy marketing subsidiary, ProLiance Energy, LLC (ProLiance Energy). Other minor operating results of the remaining ProLiance investment and Coal Mining are reflected in Other Businesses. Enterprises also has other legacy businesses that have investments in energy-related opportunities and services and other investments. All of the above is collectively referred to as the Nonutility Group. Enterprises supports the Company's regulated utilities by providing infrastructure services.

2. Summary of Significant Accounting Policies

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

Principles of Consolidation
The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries, after 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

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

Allowance for Uncollectible Accounts

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

Inventories

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

Property, Plant & Equipment

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

Utility Plant & Related Depreciation

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

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

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

Nonutility Plant & Related Depreciation

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

Impairment Reviews

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

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

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

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

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

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

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

Postretirement Obligations & Costs

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

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

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

Asset Retirement Obligations

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

Product Warranties, Performance Guarantees & Other Guarantees

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

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

Energy Contracts & Derivatives

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

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

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

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

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

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

Revenues
Most revenues are recognized as products and services are delivered to customers. Some nonutility revenues are recognized using the percentage of completion method. The Company records revenues for services and goods delivered but not billed at the end of an accounting period in Accrued unbilled revenues. 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 that of other utilities in the region. The Company is an active participant in the MISO energy markets, bidding its owned generation into the Day Ahead and Real Time markets and procuring power for its retail customers at Locational Marginal Pricing (LMP) as determined by the MISO market.

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

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

Share-Based Compensation

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

Excise & Utility Receipts Taxes

Excise taxes and a portion of utility receipts taxes are included in rates charged to customers. Accordingly, the Company records these taxes received as a component of operating revenues, which totaled $29.4 million in 2015, $32.3 million in 2014, and $29.6 million in 2013. Expense associated with excise and utility receipts taxes are recorded as a component of Taxes other than income taxes.

Operating Segments

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

Fair Value Measurements

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

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

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

3. Utility & Nonutility Plant

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

	At December 31,			
(In millions)	2015		2014	
	Original Cost	Depreciation Rates as a Percent of Original Cost	Original Cost	Depreciation Rates as a Percent of Original Cost
Gas utility plant	$3,279.7	3.4 %	$3,011.0	3.4 %
Electric utility plant	2,695.8	3.3 %	2,602.5	3.3 %
Common utility plant	55.0	3.2 %	54.3	3.2 %
Construction work in progress	59.9	—	50.9	—
Total original cost	$6,090.4		$5,718.7	

SIGECO and Alcoa Generating Corporation (AGC), a subsidiary of Alcoa, Inc. (Alcoa), own the 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, 2015, is $190.3 million with accumulated depreciation totaling $101.9 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 January 2016, Alcoa announced plans to close its smelter operations by the end of the first quarter 2016. 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 their generation, anticipating that more will be known toward the end of 2016.

Nonutility Plant, net of accumulated depreciation and amortization follows:

	At December 31,	
(In millions)	2015	2014
Computer hardware & software	$108.8	$106.1
Land & buildings	86.4	72.1
Vehicles & equipment	203.0	182.7
All other	16.4	17.1
Nonutility plant - net	$414.6	$378.0

Nonutility Plant is presented net of accumulated depreciation and amortization totaling $420.3 million and $361.9 million as of December 31, 2015 and 2014, respectively. For the years ended December 31, 2015, 2014, and 2013, the Company capitalized interest totaling $0.4 million, $0.6 million, and $0.5 million, respectively, on nonutility plant construction projects.

4. Regulatory Assets & Liabilities

Regulatory Assets
Regulatory assets consist of the following:

	At December 31,	
(In millions)	2015	2014
Future amounts recoverable from ratepayers related to:		
Benefit obligations (See Note 11)	$97.3	$105.3
Net deferred income taxes (See Note 10)	(16.9)	(14.8)
	80.4	90.5
Amounts deferred for future recovery related to:		
Cost recovery riders & other	54.6	33.3
	54.6	33.3
Amounts currently recovered in customer rates related to:		
Unamortized debt issue costs, reacquisition premiums & hedging proceeds	34.4	35.2
Demand side management programs	—	0.6
Indiana authorized trackers	42.6	25.6
Deferred coal costs	28.3	35.3
Ohio authorized trackers	17.6	12.7
Other base rate recoveries	0.1	0.4
	123.0	109.8
Total regulatory assets	$258.0	$233.6

Of the $123 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 $35 million, is 24 years. The remainder of the regulatory assets are being recovered timely through periodic recovery mechanisms. The Company has rate orders for all deferred costs not yet in rates and therefore believes that future recovery is probable.

Assets arising from benefit obligations represent the funded status of retirement plans less amounts previously recognized in the statement of income. The decrease in 2015 of approximately $8 million is primarily a result of an increase in discount rate used to value the projected benefit obligation. These decreases were somewhat offset by asset returns that were less than the assumed rate of return. The Company records a Regulatory asset for that portion related to its rate regulated utilities. See Note 11.

Regulatory Liabilities
At December 31, 2015 and 2014, the Company has approximately $433.9 million and $410.3 million, respectively, in Regulatory liabilities. Of these amounts, $399.1 million and $373.5 million relate to cost of removal obligations. The remaining amounts primarily relate to timing differences associated with asset retirement obligations and deferred financing costs.

5. Federal Business Unit Acquisition

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

The acquisition purchase price was $42.1 million, which included contingent consideration to be paid if certain new order targets were met in 2014. Those new order targets were not met in 2014 and therefore the contingent consideration was not earned.

As such, the contingent consideration liability as of December 31, 2014 of $14.8 million was reversed as operating income. The initial new order target at the end of 2014 was dependent on the signing of contracts with sufficient revenue to meet the threshold. A single contract was targeted that would have been sufficient to meet the threshold but the signing of that contract was delayed by the customer. That contract was signed in August 2015.

The Company recognized the assets acquired and the liabilities assumed, measured at their fair values as of the date of acquisition. The following table summarizes the allocation of the purchase price to the fair value of the assets acquired and liabilities assumed as of April 1, 2014.

(In millions)		
Adjusted Net Working Capital	$2.2	
Depreciable Fixed Assets	0.4	
Customer Relationships (Sales Funnel)	7.1	
ESPC Licenses	6.0	
Deferred Tax Asset	0.8	
Goodwill	27.7	
Total Assets acquired	$44.2	
Less: Unfavorable Contract Liabilities Assumed	(2.1	)
Total Purchase Consideration	$42.1	

Level 3 market inputs, such as discounted cash flows and revenue growth rates were used to derive the preliminary fair values of the identifiable intangible assets. Identifiable intangible assets include long-term customer relationships and licenses. Goodwill arising from the purchase represents intangible value the Company expects to realize over time. This value includes but is not limited to: 1) expected customer growth beyond what is in the current sales funnel and 2) the experience of the acquired work force. The goodwill, which does not amortize pursuant to accounting guidance, is deductible over a 15-year period for purposes of computing current income tax expense, and will be included in the Energy Services operating segment.

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

For the year ended December 2014 and 2013, unaudited proforma results of the combined companies, assuming the acquisition closed on January 1, 2013, would have added approximately $17.7 million and $27.6 million to consolidated revenues, respectively. For the periods presented, the impact to net income and earnings per share would have been de minimis. These proforma results may not be indicative of what actual results would have been if the acquisition had taken place on the proforma date or of future results.

6. Sale of Vectren Fuels, Inc.

On July 1, 2014, the Company announced that it had reached an agreement to sell its wholly owned coal mining subsidiary, Vectren Fuels, to Sunrise Coal, LLC (Sunrise Coal), an Indiana-based wholly owned subsidiary of Hallador Energy Company. Sunrise Coal owns and operates coal mines in the Illinois Basin. On August 29, 2014, the transaction closed. Total cash received was approximately $311 million, inclusive of a $15 million change in working capital from December 31, 2013, through closing. At June 30, 2014, the Company recorded an estimated loss on the transaction, including costs to sell, of approximately $32 million, or $20 million after tax. At December 31, 2014, the pre-tax loss of $32 million was reflected in the Consolidated Statement of Income as a $42 million charge to other operating expense, offset by $10 million in lower depreciation expense as depreciation ceased for the assets classified as held for sale at June 30, 2014. Results from Coal Mining for the year ended December 31, 2014, inclusive of the loss on sale, was a loss of $21.1 million, net of tax, compared to a loss of $16.0 million for the year ended December 31, 2013. The transaction did not meet the requirements under GAAP to qualify as discontinued operations since Vectren has significant continuing cash flows related to the purchase of coal from the buyer of these mines.

7. Investment in ProLiance Holdings, LLC

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

As a result of ProLiance exiting the natural gas marketing business on June 18, 2013, the Company recorded its share of the loss on the disposition, termination of long-term pipeline and storage commitments, and related transaction and other costs totaling $43.6 million pre-tax, or $26.8 million net of tax, during the second quarter of 2013. At the time of sale, ProLiance Holdings funded an estimated equity shortfall at ProLiance Energy of $16.6 million. To fund this estimated shortfall, the Company issued a note to ProLiance Holdings for its 61 percent ownership share of the $16.6 million shortfall, or $10.1 million, which was utilized by ProLiance Holdings to invest additional equity in ProLiance Energy. This interest-bearing note is classified as Other nonutility investments in the Consolidated Balance Sheets.

The Company's remaining investment in ProLiance at December 31, 2015, shown at its 61 percent ownership share, is as follows and reflects that it relates primarily to ProLiance's investment in LA Storage discussed below.

(In millions)	As of December 31, 2015
Cash	$2.7
Investment in LA Storage	22.2
Other midstream asset investment	4.9
Total investment in ProLiance	$29.8
Included in:	
Investments in unconsolidated affiliates	19.7
Other nonutility investments	10.1

LA Storage, LLC Storage Asset Investment

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

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

The joint venture received a demand for arbitration from Williams Midstream Natural Gas Liquids, Inc. (Williams) in February 2011 related to a sublease agreement. Williams alleged that the joint venture was negligent in its attempt to convert certain salt caverns to natural gas storage and seeks damages of $56.7 million. In August 2015, the joint venture and Williams agreed to settle the dispute. The Company's share of the settlement was not material to its results of operations or statement of financial condition.

Transactions with ProLiance
Purchases from ProLiance for resale and for injections into storage for the year ended December 31, 2013 totaled $200.5 million. The Company did not have any purchases from ProLiance for the year ended December 31, 2015 or 2014. The 2013 purchases from ProLiance all occurred prior to June 18, 2013 when ProLiance exited the natural gas marketing business.

8. Nonutility Legacy Holdings

Within the nonutility group, there are legacy investments involved in other ventures. As of December 31, 2015 and 2014, total remaining legacy investments, other than the investment in ProLiance, included in the Other Businesses portfolio total $7.0 million and $25.0 million, respectively. Further separation by type of investment follows:

	At December 31, 2015			At December 31, 2014		
		Value Included In			Value Included In	
(In millions)	Carrying Value	Other Nonutility Investments	Investments in Unconsolidated Affiliates	Carrying Value	Other Nonutility Investments	Investments in Unconsolidated Affiliates
Commercial real estate investment	$—	$—	$—	$8.0	$8.0	$—
Leveraged lease	—	—	—	15.2	15.2	—
Other investments	7.0	6.0	1.0	1.8	0.2	1.6
	$7.0	$6.0	$1.0	$25.0	$23.4	$1.6

During 2015, the Company sold its investment in commercial real estate property as well as an interest in a leveraged lease for approximate book value. At December 31, 2015, the remaining investment relates to a debt security related to the sale of commercial real estate of $5.1 million and other investments of $1.9 million.

9. Intangible Assets

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

(In millions)	At December 31,			
	2015		2014	
	Amortizing	Non-amortizing	Amortizing	Non-amortizing
Customer-related assets	$23.1	$ —	$22.5	$ —
Market-related assets	0.2	13.0	1.1	13.0
Intangible assets, net	$23.3	$ 13.0	$23.6	$ 13.0

As of December 31, 2015, the weighted average remaining life for amortizing customer-related assets and all amortizing intangibles is 12 years. These amortizing intangible assets have no significant residual values. Intangible assets are presented net of accumulated amortization totaling $9.8 million for customer-related assets and $4.3 million for market-related assets at December 31, 2015 and $10.0 million for customer-related assets and $3.4 million for market-related assets at December 31, 2014. Annual amortization associated with intangible assets totaled $3.1 million in 2015, $2.8 million in 2014 and $2.3 million in 2013. Amortization should approximate (in millions) $2.5, $2.3, $2.3, $2.3, and $2.3 in 2016, 2017, 2018, 2019, and 2020, respectively. Intangible assets are primarily in the

Nonutility Group.

10. Income Taxes

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

	Year Ended December 31,		
	2015	2014	2013
Statutory rate:	35.0 %	35.0 %	35.0 %
State & local taxes-net of federal benefit	3.6	4.1	4.6
Amortization of investment tax credit	(0.2)	(0.3)	(0.3)
Depletion	—	(2.6)	(1.5)
Domestic production deduction	(1.0)	(1.1)	—
Energy efficiency building deductions	(2.3)	(1.6)	(3.8)
Research and development credit	(1.6)	(0.3)	(0.6)
Other tax credits	(0.1)	(0.2)	(1.1)
All other-net	0.2	(0.3)	0.7
Effective tax rate	33.6 %	32.7 %	33.0 %

Significant components of the net deferred tax liability follow:

	At December 31,	
(In millions)	2015	2014
Noncurrent deferred tax liabilities (assets):		
Depreciation & cost recovery timing differences	$827.6	$757.9
Leveraged lease	—	9.8
Regulatory assets recoverable through future rates	31.6	29.2
Alternative minimum tax carryforward	(34.5)	(51.4)
Employee benefit obligations	(9.3)	(14.5)
Net operating loss & other carryforwards	(3.7)	(2.0)
Regulatory liabilities to be settled through future rates	(29.9)	(27.5)
Impairments	(3.0)	(5.6)
Deferred fuel costs - net	14.2	22.0
Other – net	12.4	7.0
Net noncurrent deferred tax liability	$805.4	$724.9

The Company has presented its deferred tax assets and deferred tax liabilities as non-current in the tables above and in the balance sheet, in accordance with ASU 2015-17, Balance Sheet Classification of Deferred Taxes. The Company early adopted ASU 2015-17 in the current year as the new standard simplifies current accounting guidance, which required entities to separately present deferred tax assets and deferred tax liabilities as current and non-current. This guidance was adopted for the year ended December 31, 2015, and has been applied retrospectively to all periods presented. The effect of this change on the December 31, 2015 and 2014 balance sheets is the reclassification of $15.3 million and $16.3 million in current deferred tax assets to long-term deferred tax liabilities, respectively. The amounts reclassified primarily represent the net of deferred tax assets arising from alternative minimum tax carryforwards and deferred tax liabilities arising from deferred fuels costs.

At December 31, 2015 and 2014, investment tax credits totaling $4.1 million and $4.7 million respectively, are included in Deferred credits & other liabilities. At December 31, 2015, the Company has alternative minimum tax carryforwards which do not expire. In addition, the Company has $3.7 million in net operating loss and general business credit carryforwards, which will expire in 5 to 20 years. The net operating loss carryforward and other carryforwards were reduced for the impacts of unrecognized tax benefits and a valuation allowance relating primarily to state net operating loss carryforwards. At December 31, 2015 and 2014, the valuation allowance was $8.1 million and $7.3 million, respectively.

The components of income tax expense follow:

(In millions)	Year Ended December 31, 2015	2014	2013
Current:			
Federal	$10.8	$24.7	$12.4
State	8.5	18.5	11.4
Total current taxes	19.3	43.2	23.8
Deferred:			
Federal	79.0	42.7	43.4
State	2.0	(4.2)	0.5
Total deferred taxes	81.0	38.5	43.9
Amortization of investment tax credits	(0.6)	(0.6)	(0.6)
Total income tax expense	$99.7	$81.1	$67.1

Uncertain Tax Positions

Unrecognized tax benefits for all periods presented were not material to the Company. The net liability on the Consolidated Balance Sheet for unrecognized tax benefits inclusive of interest, penalties and net of secondary impacts which are a component of the Deferred income taxes and are benefits, totaled $1.0 million and $1.1 million, respectively, at December 31, 2015 and 2014.

The Company and/or certain of its subsidiaries file income tax returns in the U.S. federal jurisdiction and various states. The Internal Revenue Service (IRS) has concluded examinations of the Company's U.S. federal income tax returns for tax years through December 31, 2012. The State of Indiana, the Company's primary state tax jurisdiction, has conducted examinations of state income tax returns for tax years through December 31, 2010. The statutes of limitations for assessment of federal income tax and Indiana income tax have expired with respect to tax years through 2011 except to the extent of refunds claimed on amended tax returns. The statutes of limitations for assessment of the 2009-2011 tax years related to the amended federal and Indiana income tax returns will expire in 2016 and 2017.

Final Federal Income Tax Regulations

In September 2013, the IRS released final tangible property regulations regarding the deduction and capitalization of expenditures related to tangible property. The final regulations are generally effective for tax years beginning on or after January 1, 2014, and were adopted on the 2014 federal income tax return. The IRS has been working with the utility industry to provide industry specific guidance concerning the deductibility and capitalization of expenditures related to tangible property. The IRS has indicated that it expects to issue updated or new guidance with respect to electric and natural gas transmission and distribution assets during 2016. The Company continues to evaluate the impact adoption and industry guidance will have on its consolidated financial statements. As of this date, the Company does not expect the industry guidance to have a material impact on its consolidated financial statements.

Indiana Senate Bill 1

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

11. Retirement Plans & Other Postretirement Benefits

At December 31, 2015, the Company maintains three closed qualified defined benefit pension plans, a nonqualified supplemental executive retirement plan (SERP), and a postretirement benefit plan. The defined benefit pension plans and postretirement benefit plan, which cover eligible full-time regular employees, are primarily noncontributory. The postretirement health care and life insurance plans are a combination of self-insured and fully insured plans. The qualified pension plans and the SERP are aggregated under the heading "Pension Benefits." The postretirement benefit plan is presented under the heading "Other Benefits."

Net Periodic Benefit Costs

A summary of the components of net periodic benefit cost for the three years ended December 31, 2015 follows:

	Pension Benefits			Other Benefits		
(In millions)	2015	2014	2013	2015	2014	2013
Service cost	$7.9	$7.4	$8.6	$0.4	$0.4	$0.5
Interest cost	14.6	15.5	14.7	2.0	2.3	2.0
Expected return on plan assets	(22.5)	(22.7)	(22.1)	—	—	—
Amortization of prior service cost (benefit)	0.7	1.0	1.5	(3.0)	(3.0)	(3.2)
Amortization of actuarial loss	8.5	5.0	10.1	0.7	0.4	0.7
Settlement charge	0.6	3.1	1.3	—	—	—
Net periodic benefit cost	$9.8	$9.3	$14.1	$0.1	$0.1	$—

A portion of the net periodic benefit cost disclosed in the table above is capitalized as Utility Plant. Costs capitalized in 2015, 2014, and 2013 are estimated at $3.1 million, $2.8 million, and $4.2 million, respectively.

The Company decreased the discount rate used to measure periodic cost from 4.74 percent in 2014 to 4.05 percent in 2015 due to lower benchmark interest rates that approximated the expected duration of the Company's benefit obligations as of that valuation date. The Company derives its discount rate by identifying a theoretical settlement portfolio of high quality corporate bonds sufficient to provide for the plans' projected benefit payments. For fiscal year 2016, the weighted average discount rate assumption will increase to 4.31 percent for the defined benefit pension plans, based on increased benchmark interest rates.

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

	Pension Benefits			Other Benefits		
	2015	2014	2013	2015	2014	2013
Discount rate	4.05%	4.74%	4.03%	3.95%	4.66%	3.91%
Rate of compensation increase	3.50%	3.50%	3.50%	N/A	N/A	N/A
Expected return on plan assets	7.50%	7.75%	7.75%	N/A	N/A	N/A
Expected increase in Consumer Price Index	N/A	N/A	N/A	2.50%	2.75%	2.75%

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

Benefit Obligations

A reconciliation of the Company's benefit obligations at December 31, 2015 and 2014 follows:

	Pension Benefits		Other Benefits	
(In millions)	2015	2014	2015	2014
Benefit obligation, beginning of period	$371.9	$338.4	$53.3	$51.3
Service cost – benefits earned during the period	7.9	7.4	0.4	0.4
Interest cost on projected benefit obligation	14.6	15.5	2.0	2.3
Plan participants' contributions	—	—	1.0	0.9
Plan amendments	0.5	—	—	—

Actuarial loss (gain)	(17.0)	48.5	(8.6)	3.2
Settlement loss	—	1.7	—	—
Benefit payments	(27.9)	(25.3)	(4.6)	(4.8)
Settlement payments	(1.7)	(14.3)	—	—
Benefit obligation, end of period	$348.3	$371.9	$43.5	$53.3

The accumulated benefit obligation for all defined benefit pension plans was $336.1 million and $356.4 million at December 31, 2015 and 2014, respectively. The decrease in the pension benefit obligation in 2015 is primarily due to an increase in the discount rate used to measure the obligation at year end.

Mortality Assumption Changes

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

Other Material Assumptions

The benefit obligation as of December 31, 2015 and 2014 was calculated using the following weighted average assumptions:

	Pension Benefits				Other Benefits			
	2015		2014		2015		2014	
Discount rate	4.31	%	4.05	%	4.21	%	3.95	%
Rate of compensation increase	3.50	%	3.50	%	N/A		N/A	
Expected increase in Consumer Price Index	N/A		N/A		2.50	%	2.50	%

To calculate the 2015 ending postretirement benefit obligation, medical claims costs in 2016 were assumed to be 6.0 percent higher than those incurred in 2015. That trend, beginning at 8.0 percent in 2012, was assumed to reach its ultimate trending increase of 5.0 percent by 2018 and remain level thereafter. A one-percentage point change in assumed health care cost trend rates would have changed the benefit obligation by approximately $0.2 million.

Plan Assets

A reconciliation of the Company’s plan assets at December 31, 2015 and 2014 follows:

	Pension Benefits				Other Benefits			
(In millions)	2015		2014		2015		2014	
Plan assets at fair value, beginning of period	$305.6		$323.9		$—		$—	
Actual return on plan assets	(2.0	)	20.1		—		—	
Employer contributions	22.9		1.2		3.6		3.9	
Plan participants' contributions	—		—		1.0		0.9	
Benefit payments	(27.9	)	(25.3	)	(4.6	)	(4.8	)
Settlement payments	(1.7	)	(14.3	)	—		—	
Fair value of plan assets, end of period	$296.9		$305.6		$—		$—	

The Company’s overall investment strategy for its retirement plan trusts is to maintain investments in a diversified portfolio, comprised of primarily equity and fixed income investments, which are further diversified among various asset classes. The diversification is designed to minimize the risk of large losses while maximizing total return within reasonable and prudent levels of risk. The investment objectives specify a targeted investment allocation for the pension plans of 60 percent equities, 35 percent debt, and 5 percent for other investments, including real estate. Both the equity and debt securities have a blend of domestic and international exposures. Objectives do not target a specific return by asset class. The portfolios’ return is monitored in total. Following is a description of the valuation methodologies used for trust assets measured at fair value.

Mutual Funds
The fair values of mutual funds are derived from quoted market prices or net asset values as these instruments have active markets (Level 1 inputs).

Common Collective Trust Funds (CTF's)

The Company's plans have investments in trust funds similar to mutual funds in that they are created by pooling of funds from investors into a common trust and such funds are managed by a third party investment manager. These trust funds typically give investors a wider range of investment options through this pooling of funds than those generally available to investors on an individual basis. However, unlike mutual funds, these trusts are not publicly traded in an active market. The fair values of these trusts are derived from Level 2 market inputs based on a daily calculated unit value as determined by the issuer. This daily calculated value is based on the fair market value of the underlying investments. These funds are primarily comprised of investments in equity and fixed income securities which represent approximately 30 percent and 60 percent, respectively, of their fair value as of December 31, 2015 and approximately 56 percent and 37 percent, respectively, as of December 31, 2014. Equity securities within these funds are primarily valued using quoted market prices as these instruments have active markets. From time to time, less liquid equity securities are valued using Level 2 inputs, such as bid prices or a closing price, as determined in good faith by the investment manager. Fixed income securities are valued at the last available bid prices quoted by an independent pricing service. When valuations are not readily available, fixed income securities are valued using primarily other Level 2 inputs as determined in good faith by the investment manager.

The fair value of these funds totals $99.5 million at December 31, 2015 and $155.6 million at December 31, 2014. In 2015, approximately $54 million of Level 2 investments were reallocated to Level 1 investments to maximize performance. In relation to these investments, there are no unfunded commitments. Also, the Plan can exchange shares with minimal restrictions, however, certain events may exist where share exchanges are restricted for up to 31 days.

Guaranteed Annuity Contract

One of the Company's pension plans is party to a group annuity contract with John Hancock Life Insurance Company (John Hancock). At December 31, 2015 and 2014, the estimate of undiscounted funds necessary to satisfy John Hancock's remaining obligation was $3.9 million and $3.8 million, respectively. If funds retained by John Hancock are not sufficient to satisfy retirement payments due to these retirees, the shortfall must be funded by the Company. The composite investment return, net of manager fees and other charges for the years ended December 31, 2015 and 2014 was 3.65 percent and 4.12 percent, respectively. The Company values this illiquid investment using long-term interest rate and mortality assumptions, among others, and is therefore considered a Level 3 investment. There is no unfunded commitment related to this investment.

The fair values of the Company's pension and other retirement plan assets at December 31, 2015 and December 31, 2014 by asset category and by fair value hierarchy are as follows:

	As of December 31, 2015			
(In millions)	Level 1	Level 2	Level 3	Total
Domestic equities & equity funds	$113.5	$29.8	$—	$143.3
International equities & equity funds	38.2	—	—	38.2
Domestic bonds & bond funds	36.6	48.0	—	84.6
Inflation protected security fund	—	11.2	—	11.2
Real estate, commodities & other	4.8	10.5	4.3	19.6
Total plan investments	$193.1	$99.5	$4.3	$296.9

	As of December 31, 2014			
(In millions)	Level 1	Level 2	Level 3	Total
Domestic equities & equity funds	$62.8	$87.3	$—	$150.1
International equities & equity funds	38.4	—	—	38.4
Domestic bonds & bond funds	38.8	47.1	—	85.9
Inflation protected security fund	—	11.1	—	11.1

Real estate, commodities & other	5.8	10.1	4.2	20.1
Total plan investments	$145.8	$155.6	$4.2	$305.6

83

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

(In millions)	2015	2014
Fair value, beginning of year	$4.2	$4.1
Unrealized gains related to investments still held at reporting date	0.2	0.1
Purchases, sales & settlements, net	(0.1)	—
Fair value, end of year	$4.3	$4.2

Funded Status

The funded status of the plans as of December 31, 2015 and 2014 follows:

	Pension Benefits		Other Benefits	
(In millions)	2015	2014	2015	2014
Qualified Plans				
Benefit obligation, end of period	$(328.7)	$(351.7)	$(43.5)	$(53.3)
Fair value of plan assets, end of period	296.9	305.6	—	—
Funded Status of Qualified Plans, end of period	(31.8)	(46.1)	(43.5)	(53.3)
Benefit obligation of SERP Plan, end of period	(19.6)	(20.2)	—	—
Total funded status, end of period	$(51.4)	$(66.3)	$(43.5)	$(53.3)
Accrued liabilities	$1.2	$1.2	$4.6	$4.6
Deferred credits & other liabilities	$50.2	$65.1	$38.9	$48.7

Expected Cash Flows

The Company currently anticipates making contributions of $15.0 million to qualified pension plans in 2016. In addition, the Company expects to make contributions totaling approximately $1.2 million into the SERP plan and approximately $3.3 million into the postretirement plan.

Estimated retiree pension benefit payments, including the SERP, projected to be required during the years following 2015 are approximately (in millions) $25.1 in 2016, $35.9 in 2017, $25.8 in 2018, $27.0 in 2019, $29.6 in 2020, and $135.2 in years 2021-2025. Expected benefit payments projected to be required for postretirement benefits during the years following 2015 (in millions) are approximately $4.6 in 2016, $4.4 in 2017, $4.6 in 2018, $4.8 in 2019, $5.1 in 2020, and $25.5 in years 2021-2025.

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

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

	Pensions		Other Benefits	
(In millions)	Prior Service Cost	Net Gain or Loss	Prior Service Cost	Net Gain or Loss
Balance at January 1, 2013	$4.5	$136.2	$(23.1)	$11.2
Amounts arising during the period	—	(58.8)	(0.2)	(2.4)
Reclassification to benefit costs	(1.5)	(10.1)	3.2	(0.7)
Balance at December 31, 2013	$3.0	$67.3	$(20.1)	$8.1
Amounts arising during the period	—	49.4	—	3.2
Reclassification to benefit costs	(1.0)	(5.0)	3.0	(0.4)
Balance at December 31, 2014	$2.0	$111.7	$(17.1)	$10.9
Amounts arising during the period	0.5	6.9	—	(8.6)
Reclassification to benefit costs	(0.7)	(8.5)	3.0	(0.7)

Balance at December 31, 2015	$1.8	$110.1	$(14.1)	$1.6

84

Following is a reconciliation of the amounts in Accumulated other comprehensive income (AOCI) and Regulatory assets related to retirement plan obligations at December 31, 2015 and 2014.

(In millions)	2015		2014	
	Pensions	Other Benefits	Pensions	Other Benefits
Prior service cost	$1.8	$(14.1)	$2.0	$(17.1)
Unamortized actuarial gain/(loss)	110.1	1.6	111.7	10.9
	111.9	(12.5)	113.7	(6.2)
Less: Regulatory asset deferral	(109.6)	12.3	(111.4)	6.1
AOCI before taxes	$2.3	$(0.2)	$2.3	$(0.1)

Related to pension plans, $0.4 million of prior service cost and $7.2 million of actuarial gain/loss is expected to be amortized to cost in 2016. Related to other benefits, no actuarial gain/loss is expected to be amortized to periodic cost in 2016, and $3.0 million of prior service cost is expected to reduce costs in 2016.

Multiemployer Benefit Plan

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

Expense is recognized as payments are accrued for work performed or when withdrawal liabilities are probable and estimable. Expense associated with multiemployer plans was $32.7 million, $32.4 million and $33.2 million for the years ended December 31, 2015, 2014, and 2013, respectively. During 2015, the Company made contributions to these multiemployer plans on behalf of employees that participate in approximately 250 local unions. Contracts with these unions are negotiated with trade agreements through two primary contractor associations. These trade agreements have varying expiration dates ranging from 2016 through 2020. The average contribution related to these local unions was less than $0.1 million, and the largest contribution was $3.5 million. Multiple unions can contribute to a single multiemployer plan. The Company made contributions to at least 62 plans in 2015, five of which are considered significant plans based on, among other things, the amount of the contributions, the number of employees participating in the plan, and the funded status of the plan.

The Company's participation in the significant plans is outlined in the following table. The Employer Identification Number (EIN) / Pension Plan Number column provides the EIN and three digit pension plan numbers. The most recent Pension Protection Act Zone Status available in 2015 and 2014 is for the plan year end at January 31, 2014 and 2013 for the Central Pension Fund, December 31, 2014 and 2013 for the Pipeline Industry Benefit Fund, May 31, 2014 and 2013 for the Indiana Laborers Pension Fund, August 1, 2014 and 2013 for the Ohio Operating Engineers Pension Fund, and December 31, 2014 and 2013 for the Minnesota Laborers Pension Fund, respectively. Generally, plans in the red zone are less than 65 percent funded, plans in the yellow zone are less than 80 percent funded and plans in the green zone are at least 80 percent funded. The FIP/RP Status Pending / Implemented column indicates plans for which a funding improvement plan ("FIP") or rehabilitation plan ("RP") is either pending or has been implemented. The multiemployer contributions listed in the table below are the Company's multiemployer contributions made in 2015, 2014, and 2013.

85

(In millions)

Pension Fund	EIN/Pension Plan Number	Pension Protection Act Zone Status		FIP/RP Status Pending/Implemented	Multiemployer Contributions			Surcharge Imposed
		2015	2014		2015	2014	2013	
Central Pension Fund	36-6052390-001	Green	Green	No	$7.2	$7.7	$8.5	No
Pipeline Industry Benefit Fund	73-0742835-001	Green	Green	No	4.0	5.1	5.3	No
Indiana Laborers Pension Fund (1)	35-6027150-001	Yellow	Yellow	Implemented	4.1	3.5	2.4	No
Ohio Operating Engineers Pension Fund	31-6129968-001	Green	Green	No	2.2	1.7	1.5	No
Minnesota Laborers Pension Fund	41-6159599-001	Green	Green	No	1.8	2.2	2.8	No
Other					13.4	12.2	12.7	
Total Contributions					$32.7	$32.4	$33.2	

(1) Federal law requires pension plans in endangered status to adopt a funding improvement plan aimed at restoring the financial health of the plan. In December 2014, the Multiemployer Pension Reform Act of 2014 was passed and permanently extended the Pension Protection Act of 2006 multiemployer plan critical and endangered status funding rules, among other things, including providing a provision for a plan sponsor to suspend or reduce benefit payments to preserve plans in critical and declining status. Since the Indiana Laborers Pension Fund became endangered as of June 1, 2008, a funding improvement plan was previously set in place to begin June 1, 2009. The funding improvement plan requires that the plan's funded percentage improve at least 33 percent of the way to 100 percent over a 10-year period. The target for this plan under the law is a funded percentage of 78 percent by 2019. The plan must also meet the federal minimum funding requirements during this 10-year period. As of December 31, 2015, the plan has met these funding requirements and is expected to meet the target funded percentage by 2019.

While not considered significant to the Company, there are nine plans in red zone status receiving Company contributions. There are also nine other plans where Company contributions exceed 5 percent of each plan's total contributions and one of these plans was considered significant to the Company.

Defined Contribution Plan

The Company also has defined contribution retirement savings plans that are qualified under sections 401(a) and 401(k) of the Internal Revenue Code and include an option to invest in Vectren common stock, among other alternatives. During 2015, 2014 and 2013, the Company made contributions to these plans of $11.0 million, $9.1 million, and $7.5 million, respectively.

12. Borrowing Arrangements

Long-Term Debt

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

	At December 31,	
(In millions)	2015	2014
Utility Holdings		
Fixed Rate Senior Unsecured Notes		
2015, 5.45%	—	75.0
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	—
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	—
2055, 4.51%	40.0	—
Total Utility Holdings	1,000.0	875.0
Indiana Gas		
Fixed Rate Senior Unsecured Notes		
2015, Series E, 7.15%	—	5.0
2015, Series E, 6.69%	—	5.0
2015, Series E, 6.69%	—	10.0
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	116.0
SIGECO		
First Mortgage Bonds		
2016, 1986 Series, 8.875%	13.0	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 0.784%, 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	—

2055, 2015 Series Warrick County, 2.375%, tax-exempt	15.2	—
Total SIGECO	305.7	267.5

(In millions)	At December 31, 2015	2014
Vectren Capital Corp.		
Fixed Rate Senior Unsecured Notes		
2015, 5.31%	—	75.0
2016, 6.92%	60.0	60.0
2017, 3.48%	75.0	75.0
2019, 7.30%	60.0	60.0
2022, 3.33%	75.0	—
2025, 4.53%	50.0	50.0
2030, 3.90%	75.0	—
Total Vectren Capital Corp.	395.0	320.0
Total long-term debt outstanding	1,796.7	1,578.5
Current maturities of long-term debt	(73.0)	(170.0)
Unamortized debt premium & discount - net	(0.9)	(1.2)
Total long-term debt-net	$1,722.8	$1,407.3

Indiana Gas Unsecured Note Retirement

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

SIGECO Debt Issuance

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

Vectren Utility Holdings, Vectren Capital, and Indiana Gas Debt Transactions

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

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

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

Vectren Capital Unsecured Note Retirement

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

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

Vectren Capital 2013 Term Loan
On August 6, 2013, Vectren Capital entered into a $100 million three-year term loan agreement. Loans under the term loan agreement bore interest at either a Eurodollar rate or base rate plus an additional margin which was based on the Company's credit rating. Interest periods were variable and could have ranged from seven days to six months. The proceeds from this debt transaction were used to repay short-term borrowings outstanding under Vectren Capital's credit facility. The loan agreement was guaranteed by Vectren Corporation and included customary representations, warranties, and covenants, including a leverage covenant consistent with leverage covenants contained in other Vectren Capital borrowing arrangements. The Company received net proceeds of approximately $100 million in August 2013 and repaid the loan in August of 2014.

SIGECO 2013 Debt Refund and Reissuance
During the second quarter of 2013, approximately $111 million of SIGECO's tax-exempt long-term debt was redeemed at par plus accrued interest. Approximately $62 million of tax-exempt long-term debt was reissued on April 26, 2013 at interest rates that are fixed to maturity, receiving proceeds, net of issuance costs, of approximately $60 million. The terms are $22.2 million at 4.00 percent per annum due 2038, and $39.6 million at 4.05 percent per annum due 2043.

The remaining approximately $49 million of the called debt was remarketed on August 13, 2013. The remarketed tax-exempt debt has a fixed interest rate of 1.95 percent per annum until September 13, 2017. SIGECO closed on this remarketing and received net proceeds of $48.3 million on August 28, 2013.

Utility Holdings 2013 Debt Call and Reissuance
On April 1, 2013, VUHI exercised a call option at par on Utility Holdings' $121.6 million 6.25 percent senior unsecured notes due in 2039. This debt was refinanced on June 5, 2013, with proceeds from a private placement note purchase agreement entered into on December 20, 2012 with a delayed draw feature. It provides for the following tranches of notes: (i) $45 million, 3.20 percent senior guaranteed notes, due June 5, 2028 and (ii) $80 million, 4.25 percent senior guaranteed notes, due June 5, 2043. Total proceeds received from these notes, net of issuance costs, were $44.8 million and $79.6 million, respectively. The notes are unconditionally guaranteed by Indiana Gas, SIGECO and VEDO.

On August 22, 2013, VUHI entered into a private placement note purchase agreement with a delayed draw feature, pursuant to which institutional investors agreed to purchase $150 million of senior guaranteed notes with a fixed interest rate of 3.72 percent per annum, due December 5, 2023. The notes were unconditionally guaranteed by Indiana Gas, SIGECO, and VEDO. On December 5, 2013, the Company received net proceeds of $149.1 million from the issuance of the senior guaranteed notes, which were used to refinance $100 million of 5.25 percent senior notes that matured August 1, 2013, for capital expenditures, and for general corporate purposes.

Mandatory Tenders
At December 31, 2015, 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 2015 sinking fund requirement by this means and, accordingly, the sinking fund requirement for 2015 is excluded from Current liabilities in the Consolidated Balance Sheets. At December 31, 2015, $1.3 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 $3.1 billion at December 31, 2015.

Consolidated maturities of long-term debt during the five years following 2015 (in millions) are $73.0 in 2016, $75.0 in 2017, $100.0 in 2018, $60.0 in 2019, $100.0 in 2020, and $1,387.8 thereafter.

Debt Guarantees

Vectren Corporation guarantees Vectren Capital's long-term debt, including current maturities, and short-term debt. Vectren Capital's long-term debt, including current maturities outstanding at December 31, 2015 totaled $395 million. Vectren Capital had no short-term obligations outstanding at December 31, 2015. Utility Holdings' currently outstanding long-term and short-term debt is jointly and severally guaranteed by Indiana Gas, SIGECO, and VEDO. Utility Holdings' long-term debt and short-term debt outstanding at December 31, 2015, totaled $1 billion and $15 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, 2015 the Company was in compliance with all financial covenants.

Short-Term Borrowings

At December 31, 2015, the Company had $600 million of short-term borrowing capacity, including $350 million for the Utility Group and $250 million for the wholly owned Nonutility Group and corporate operations. As reduced by borrowings currently outstanding, approximately $335 million was available for the Utility Group operations and $250 million was available for the wholly owned Nonutility Group and corporate operations. On October 31, 2014, Vectren Capital's and Utility Holdings' short-term credit facilities, totaling $600 million in borrowing capacity, were amended to extend their maturity until October 31, 2019. These facilities are used to supplement working capital needs and also to fund capital investments and debt redemptions until financed on a long-term basis. The Vectren Capital facility has a letter of credit limit of $50 million and the Utility Holdings' facility has a letter of credit limit of $100 million. As of December 31, 2015, there were no letters of credit outstanding under the facilities.

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

	Utility Group Borrowings						Nonutility Group Borrowings					
(In millions)	2015		2014		2013		2015		2014		2013	
As of Year End												
Balance Outstanding	$14.5		$156.4		$28.6		$—		$—		$40.0	
Weighted Average Interest Rate	0.55	%	0.50	%	0.29	%	N/A		N/A		1.27	%
Annual Average												
Balance Outstanding	$53.8		$35.6		$119.6		$24.8		$34.5		$119.3	
Weighted Average Interest Rate	0.38	%	0.34	%	0.34	%	1.33	%	1.29	%	1.35	%
Maximum Month End Balance Outstanding	$121.5		$156.4		$176.1		$69.1		$76.3		$173.8	

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

13. Common Shareholders' Equity

Authorized, Reserved Common and Preferred Shares
At December 31, 2015 and 2014, the Company was authorized to issue 480 million shares of common stock and 20 million shares of preferred stock. Of the authorized common shares, approximately 5.1 million shares at December 31, 2015 and 5.3 million shares at December 31, 2014 were reserved by the board of directors for issuance through the Company's share-based compensation plans, benefit plans, and dividend reinvestment plan. At December 31, 2015 and 2014, there were 392.1 million and 392.2 million, respectively, of authorized shares of common stock and all authorized shares of preferred stock, available for a variety of general corporate purposes, including future public offerings to raise additional capital.

14. Earnings Per Share

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

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

The following table illustrates the basic and dilutive EPS calculations for the three years ended December 31, 2015:

	Year Ended December 31,		
(In millions, except per share data)	2015	2014	2013
Numerator:			
Reported net income (Numerator for Diluted EPS)	$197.3	$166.9	$136.6
Denominator:			
Weighted-average common shares outstanding (Basic EPS)	82.7	82.5	82.3
Conversion of share-based compensation arrangements	0.0	0.0	0.1
Adjusted weighted-average shares outstanding and assumed conversions outstanding (Diluted EPS)	82.7	82.5	82.4
Basic earnings per share	$2.39	$2.02	$1.66
Diluted earnings per share	$2.39	$2.02	$1.66

For the years ended December 31, 2015 , 2014, and 2013, all options and equity based instruments were dilutive but immaterial.

15. Accumulated Other Comprehensive Income

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

	2013			2014		2015	
(In millions)	Beginning of Year Balance	Changes During Year	End of Year Balance	Changes During Year	End of Year Balance	Changes During Year	End of Year Balance
Unconsolidated affiliates	$(4.6)	$4.6	$—	$—	$—	$—	$—

Pension & other benefit costs	(2.6)	1.4	(1.2)	(1.0)	(2.2)	0.1	(2.1)
Deferred income taxes	2.9	(2.4)	0.5	0.4	0.9	—	0.9
Accumulated other comprehensive income (loss)	$(4.3)	$3.6	$(0.7)	$(0.6)	$(1.3)	$0.1	$(1.2)

Accumulated other comprehensive income arising from unconsolidated affiliates was previously primarily the Company’s portion of ProLiance Holdings, LLC’s accumulated comprehensive income related to use of cash flow hedges. (See Note 7 for more information on ProLiance.)

16. Share-Based Compensation & Deferred Compensation Arrangements

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

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

	Year Ended December 31,		
(In millions)	2015	2014	2013
Total cost of share-based compensation	$19.4	$25.2	$14.8
Less capitalized cost	4.8	5.3	2.8
Total in other operating expense	14.6	19.9	12.0
Less income tax benefit in earnings	5.7	7.9	4.8
After tax effect of share-based compensation	$8.9	$12.0	$7.2

Share-Based Awards & Other Awards

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

A limited number of awards to certain subsidiary officers and awards to non-officer employees are time-vested awards, vest ratably over a three or five-year period, and are primarily settled in cash. In addition, non-employee directors receive a portion of their fees in share-based awards. These awards to non-employee directors are not performance-based and generally vest over one year. The majority of officers and non-employee directors must choose between either settling awards in cash or deferring awards into a deferred compensation plan (where the value is eventually withdrawn in cash). A limited number of subsidiary officers may either settle awards in shares or defer awards into a deferred compensation plan at their discretion. The number of such awards that may settle in shares, but are accounted for as liability awards due to their potential to be taken in cash when withdrawn from the deferred compensation plan, was less than 100,000 units as of December 31, 2015, 2014 or 2013.

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

A summary of the status of awards separated between those accounted for as liabilities and equity as of December 31, 2015 and 2014, and changes during the years ended December 31, 2015 and 2014, follow:

	Equity Awards		Liability Awards	
	Units	Wtd. Avg. Grant Date Fair value	Units	Fair value
Awards at January 1, 2014	79,957	$29.12	731,251	
Granted	5,910	31.24	331,344	
Vested	(51,594)	28.36	(347,031)	
Forfeited	—	—	(22,405)	
Awards at December 31, 2014	34,273	$30.55	693,159	$46.23
Granted	13,657	30.39	394,967	
Vested	(29,232)	29.87	(389,331)	
Forfeited	(3,325)	30.95	(52,308)	
Awards at December 31, 2015	15,373	$31.63	646,487	$42.42

As of December 31, 2015, there was $15.4 million of total unrecognized compensation cost associated with outstanding grants. That cost is expected to be recognized over a weighted-average period of 1.6 years. The total fair value of shares vested for liability awards during the years ended December 31, 2015, 2014, and 2013, was $16.6 million, $15.1 million, and $5.7 million, respectively. The total fair value of equity awards vesting during the years ended December 31, 2015, 2014, and 2013 was $1.1 million, $0.9 million, $0.4 million, respectively.

Deferred Compensation Plans

The Company has nonqualified deferred compensation plans, which permit eligible officers and non-employee directors to defer portions of their compensation and vested share-based compensation. A record keeping account is established for each participant, and the participant chooses from a variety of measurement funds for the deemed investment of their accounts. The measurement funds are similar to the funds in the Company's defined contribution plan and include an investment in phantom stock units of the Company. The account balance fluctuates with the investment returns on those funds. The liability associated with these plans totaled $31.2 million at both December 31, 2015 and 2014. Other than $1.4 million, which is classified in Accrued liabilities at both December 31, 2015 and 2014, the liability is included in Deferred credits & other liabilities. The impact of these plans on Other operating expenses was expense of $0.1 million in 2015, $5.0 million in 2014 and $4.0 million in 2013. The amount recorded in earnings related to the investment activities in Vectren phantom stock associated with these plans during the years ended December 31, 2015, 2014, and 2013, was income of $0.4 million, and cost of $4.0 million and $2.6 million, respectively.

The Company has certain investments currently funded primarily through corporate-owned life insurance policies. These investments, which are consolidated, are available to pay deferred compensation benefits. These investments are also subject to the claims of the Company's creditors. The cash surrender value of these policies included in Other corporate & utility investments on the Consolidated Balance Sheets were $30.1 million and $32.3 million at December 31, 2015 and 2014, respectively. Those investments generated losses of $2.1 million in 2015, and earnings of $2.8 million in 2014, and $4.8 million in 2013. This activity is reflected in Other income - net.

17. Commitments & Contingencies

Commitments

Future minimum lease payments required under operating leases that have initial or remaining noncancelable lease terms in excess of one year during the five years following 2015 and thereafter (in millions) are $8.6 in 2016, $5.7 in 2017, $3.8 in 2018, $2.1 in 2019, $1.9 in 2020, and $8.3 thereafter. Total lease expense, for these type of commitments, (in millions) was $11.1 in 2015, $13.2 in 2014, and $9.9 in 2013.

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

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

Specific to ESG, in its role as a general contractor in the performance contracting industry, at December 31, 2015, there are 42 open surety bonds supporting future performance. The average face amount of these obligations is $9.8 million, and the largest obligation has a face amount of $51.0 million. The maximum exposure from these obligations is limited by the level of work already completed and guarantees issued to ESG by various subcontractors. At December 31, 2015, approximately 39 percent of work was completed on projects with open surety bonds. A significant portion of these open surety bonds will be released within one year. In instances where ESG operates facilities, project guarantees extend over a longer period. In addition to its performance obligations, ESG also warrants the functionality of certain installed infrastructure generally for one year and the associated energy savings over a specified number of years.

Based on a history of meeting performance obligations and installed products operating effectively, no liability or cost has been recognized for the periods presented.

Corporate Guarantees
The Company issues parent level guarantees to certain vendors and customers of its wholly owned subsidiaries. These guarantees do not represent incremental consolidated obligations; rather, they represent parental guarantees of subsidiary obligations to allow those subsidiaries the flexibility to conduct business without posting other forms of collateral. At December 31, 2015, parent level guarantees support a maximum of $185 million of ESG's performance contracting commitments, warranty obligations, project guarantees, and energy savings guarantees. Further, an energy facility operated by ESG and managed by Keenan Ft. Detrick Energy, LLC (Keenan), is governed by an operations agreement. All payment obligations to Keenan under this agreement are also guaranteed by the Company. The Company guarantee of the Keenan Ft. Detrick Energy operations agreement does not state a maximum guarantee. Due to the nature of work performed under this contract, the Company cannot estimate a maximum potential amount of future payments.

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

While there can be no assurance that the Company guarantee provisions will not be called upon, the Company believes that the likelihood of a material amount being triggered under any of these provisions is remote.

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

18. Gas Rate and Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement

The Company monitors and maintains its natural gas distribution system to ensure natural gas is delivered in a safe and efficient manner. The Company's natural gas utilities are currently engaged in programs to replace bare steel and cast iron infrastructure and other activities in both Indiana and Ohio to mitigate risk, improve the system, and comply with applicable regulations, many of which are a 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.

In April 2011, Indiana Senate Bill 251 (Senate Bill 251) was signed into Indiana law. The law 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 Commission, 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.

In April 2013, Indiana Senate Bill 560 (Senate Bill 560) was signed into Indiana law. This legislation 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.

In June 2011, Ohio House Bill 95 (House Bill 95) was signed into law. Outside of a base rate proceeding, this legislation permits a natural gas utility to apply for recovery of much of its capital expenditure program. The 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 recognized in the Consolidated Statements of Income currently. The recording of post-in-service carrying costs and depreciation deferral is limited by individual qualifying projects to three years after being placed into service at SIGECO and four years after being placed into service at Indiana Gas. At December 31, 2015 and December 31, 2014, the Company has regulatory assets totaling $19.9 million and $16.4 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 filed pursuant to Senate Bill 251 and 560, discussed further below.

Requests for Recovery under Indiana Regulatory Mechanisms
On August 27, 2014, the IURC issued an Order (August 2014 Order) approving the Company’s seven-year capital infrastructure replacement and improvement 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 via a fixed monthly charge per residential customer.

On September 26, 2014, the OUCC filed an appeal of the IURC's finding that the remaining value of retired assets replaced during the infrastructure projects should not be netted against the cost being recovered in the tracking mechanism. In June 2015, the Indiana Court of Appeals issued an opinion in favor of the Company that affirmed the IURC's August 2014 Order approving the infrastructure plan.

On January 14, 2015, the IURC issued an Order approving the Company's initial request for recovery of the revenue requirement through June 30, 2014 as part of its approved seven-year plan. Also, consistent with the guidelines set forth in the original August 2014 Order, the IURC approved the Company’s update to its seven-year plan, to reflect changes to project prioritization as a result of both additional risk modeling and changes to estimated project costs.

On April 1, 2015, the Company filed its second request for recovery of the revenue requirement associated with capital investment and applicable operating costs through December 31, 2014. On June 1, 2015, the Company amended its case to delay the recovery of a portion of the investment associated with Senate Bill 560 made from July 2014 to December 2014, until its third filing when it committed to provide additional project detail for the later years of the plan. This commitment was as a result of an Indiana Court of Appeals decision regarding the approval of Northern Indiana Public Service Company's (NIPSCO) proposed electric Transmission, Distribution, and Storage Improvement Charge (TDSIC) plan, and challenges to TDSIC plans filed by other Indiana utilities.

On July 22, 2015, the IURC issued an Order, approving the recovery of these investments consistent with the Company's proposal, with modification, specifically to the rate of return applicable to the Senate Bill 251 compliance component. The IURC found that the overall rate of return to be applied to the investment in determining the revenue requirement is to be updated with each filing, reflecting 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 base rate case. This IURC interpretation of the overall rate of return to be used is the same as that already in place for the Senate Bill 560 component.

On October 1, 2015, the Company filed its third request for recovery of the revenue requirement associated with capital investment and applicable operating costs through June 30, 2015, including investment associated with Senate Bill 560 made from July 2014 to December 2014 that had been delayed in the second request. The Company provided an update to its seven-year plan, as well as additional detail on the planned investments included in the plan. The updated plan reflects capital expenditures of approximately $1 billion, an increase of $100 million from the previous plan, of which $272 million has been spent as of December 31, 2015. The ability to include new projects as part of an updated Senate Bill 560 plan has been challenged in this case.

As of December 31, 2015, the Commission has approved project categories that encompass planned infrastructure investments during the plan term of approximately $800 million of the proposed $1 billion of capital spend. The remaining proposed amount is now pending approval in the third request for recovery. Pursuant to the process outlined in Senate Bill 560, the Company expects an order in early 2016.

At December 31, 2015 and December 31, 2014, the Company has regulatory assets totaling $28.6 million and $11.4 million, respectively, associated with the return on investment as well as the deferral of depreciation and other operating expenses.

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 and certain other infrastructure. 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. To date, the Company has made capital investments under this rider totaling $202.5 million. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $18.2 million and $13.1 million at December 31, 2015 and December 31, 2014, respectively. Due to the expiration of the initial five-year term for the DRR in early 2014, the Company filed a request in August 2013 to extend and expand the DRR. 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 other infrastructure investments. The Order limits the resulting DRR fixed charge per month for residential and small general service customers to specific graduated levels over the next five years. The Company's five-year capital expenditure plan related to these infrastructure investments for calendar years 2013 through 2017 totals approximately $200 million. 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; however, the plan is not expected to exceed those caps. In addition, the Order approved the Company's commitment that the DRR can only be further extended as part of a base rate case. On August 26, 2015, the Company received an Order approving its adjustment to the DRR for recovery of costs incurred through December 31, 2014.

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 near the expiration of the DRR. As such, the bill impact limits discussed below are not expected to be reached given the Company's capital expenditure plan during the remaining two-year time frame.

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 have 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. As of December 31, 2015, the Company's deferrals have not reached this bill impact cap. In addition, the Orders approved the Company's proposal that subsequent requests for accounting authority will be filed annually in April. The Company submitted its most recent annual filing on April 30, 2015, which covers the Company’s capital expenditure program through calendar year 2015. During 2015 and 2014, these approved capital expenditure programs under House Bill 95 generated Other income associated with the debt-related post-in-service carrying costs totaling $6.4 million and $3.9 million, respectively. Deferral of deprecation and property tax expenses related to these programs in 2015 and 2014 totaled $5.4 million and $3.1 million, respectively.

Other Regulatory Matters

Indiana Gas GCA Cost Recovery Issue
On July 1, 2014, Indiana Gas filed its recurring quarterly Gas Cost Adjustment (GCA) mechanism, which included recovery of gas cost variances incurred for the period January through March 2014. In August 2014, the OUCC filed testimony opposing the recovery of approximately $3.9 million of natural gas commodity purchases incurred during this period on the basis that a gas cost incentive calculation had not been properly performed. The calculation at issue is performed by the Company's supply administrator. In the winter period at issue, a pipeline force majeure event caused the gas to be priced at a location that was impacted by the extreme winter temperatures. After further review, the OUCC modified its position in testimony filed on November 5, 2014, and suggested a reduced disallowance of $3 million. The IURC moved this specific issue to a sub-docket proceeding. On April 1, 2015, a stipulation and settlement agreement between the Company, the OUCC, and the Company’s supply administrator was filed in this proceeding. The IURC issued an Order on June 10, 2015 which approved the stipulation and settlement agreement, which resulted in recovery of approximately $1.4 million of the disputed amount via the Company’s GCA mechanism, with the remaining $1.6 million received from the gas supply administrator.

Indiana Gas & SIGECO Gas Decoupling Extension Filing
On September 9, 2015, the IURC issued an Order granting the extension of the current decoupling mechanism in place at both Indiana gas companies and recovery of conservation program costs through December 2019.

19. Electric Rate and Regulatory Matters

SIGECO Electric Environmental Compliance Filing
On January 28, 2015, the IURC issued an Order (January 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 mercury and air toxic standards (MATS) effective in 2015 and to address an outstanding Notice of Violation (NOV) from the EPA. As of December 31, 2015, approximately $30 million has been spent on equipment to control mercury in both air and water emissions, and $29 million to address the issues raised in the NOV proceeding on the increase in sulfur trioxide emissions. The total investment is estimated to be between $75 million and $85 million. The Order approved the Company’s request for deferred accounting treatment, as supported by provisions under Indiana Senate Bill 29 (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 occurring in 2015 and 2016. As of December 31, 2015, the Company has approximately $2.7 million deferred related to depreciation, property tax, and operating expense, and $1.1 million deferred related to post-in-service carrying costs.

In March 2015, the Company was notified that certain parties had filed a Notice of Appeal with the Indiana Court of Appeals in response to the IURC's Order. In June 2015, Joint Appellants' Citizens Action Coalition of Indiana, Inc., Sierra Club, Inc., and Valley Watch, Inc. (the appellants) filed a brief which challenged the sufficiency of the findings in the IURC's January Order approving the Company's investments and proposed accounting treatment in terms of whether that Order made certain findings required by statute. On October 29, 2015, the Indiana Court of Appeals issued its opinion affirming the IURC's findings with regard to equipment required to comply with MATS and certain national pollutant discharge elimination system rules (approximately $35 million). The Court remanded the case back to the IURC so that it can make the findings required by statute with regard to equipment required by the NOV (approximately $40 million). On February 12, 2016, the appellants filed a petition to reopen the evidentiary record in the case in order to submit additional evidence. The Company has opposed the motion and believes the IURC already has a sufficient record in this case. As it pertains to the equipment requirement required by the NOV, given the Commission's previous approval of this project, the Company believes the Commission will make these findings and issue a new order in support of the project.

SIGECO Electric Demand Side Management (DSM) Program Filing
On August 31, 2011, the IURC issued an Order approving an initial three-year DSM plan in the SIGECO electric service territory that complied with the IURC's energy saving targets. Consistent with the Company's proposal, the Order approved, among other items, the following: 1) recovery of costs associated with implementing the DSM Plan; 2) the recovery of a performance incentive mechanism based on measured savings related to certain DSM programs; 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 year ended December 31, 2015, 2014, and 2013, the Company recognized electric utility revenue of $10.1 million, $8.7 million, and $5.0 million, respectively, associated with this approved lost margin recovery mechanism.

On March 28, 2014, Indiana Senate Bill 340 was signed into law. This legislation ended electric DSM programs on December 31, 2014 that had been conducted to meet the energy savings requirements established by the IURC in 2009. The legislation also allows for industrial customers to opt out of participating in energy efficiency programs. As of January 1, 2015, approximately 80 percent of the Company's eligible industrial load has opted out of participation in the applicable energy efficiency programs. The Company filed a request for IURC approval of a new portfolio of DSM programs on May 29, 2014 to be offered in 2015. On October 15, 2014, the IURC issued an Order approving a Settlement between the OUCC and the Company regarding the new portfolio of DSM programs effective January 2015, and new programs were implemented during the first quarter of 2015.

On May 6, 2015, Indiana's governor signed Indiana Senate Bill 412 (Senate Bill 412) into law requiring electricity suppliers to submit energy efficiency plans to the IURC at least once every three years. Senate Bill 412 also supports 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. In September 2015, the Company received an Order to continue offering and recovering the associated cost of its 2015 programs until March 31, 2016. In October 2015, the OUCC and Citizens Action Coalition of Indiana filed testimony recommending the rejection of the Company's plan, contending it was not reasonable under the terms of Senate Bill 412 due to the program design and the Company's proposal to recover lost revenues and incentives associated with the measures. Vectren filed rebuttal testimony in October 2015 defending the plan's compliance with Senate Bill 412. The Company expects an order in the first quarter of 2016.

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. The joint parties seek to reduce the 12.38 percent ROE used in the MISO transmission owners' rates, including SIGECO's formula transmission rates, to 9.15 percent, and to set a capital structure in which the equity component does not exceed 50 percent. A second customer complaint case was filed on February 11, 2015 as the maximum FERC-allowed refund period for the November 12, 2013 case ended February 11, 2015. As of December 31, 2015, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $140.2 million at December 31, 2015.

These joint complaints are similar to a complaint against the New England Transmission Owners (NETO) filed in September 2011, which requested that the 11.14 percent incentive return granted on qualifying investments in NETO be lowered. On October 16, 2014, the FERC issued an Order in the NETO case approving a 10.57 percent return on equity and a calculation methodology.

The FERC acknowledged that the pending complaint raised against the MISO transmission owners is reasonable and denied the portion of the complaint addressing the equity component of the capital structure. An initial decision from its administrative law judge was received on December 22, 2015, authorizing the transmission owners to collect a Base ROE of 10.32 percent from November 12, 2013 through February 11, 2015 (the "first refund period"). The FERC is expected to rule on the proposed order in late 2016. A procedural schedule has been established for the second customer complaint case, establishing a target date of June 30, 2016 for the initial decision.

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. Once the FERC sets a new ROE in the complaint case, this adder will be applied to that ROE, with retroactive billing to occur back to January 7, 2015.

The Company has established a reserve considering both the initial decision and the approved 50 basis points adder.

20. Environmental Matters

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

With the trend toward stricter standards, greater regulation, and more extensive permit requirements, the Company's investment in compliant infrastructure, and the associated operating costs have increased and are expected to increase in the future. Similar to the costs associated with federal mandates in the Pipeline Safety Law, Indiana Senate Bill 251 (Senate Bill 251) is also applicable to federal environmental mandates impacting SIGECO's electric operations.

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 back to the appellate court for further proceedings consistent with the opinion. MATS compliance was required to commence April 16, 2015, and the Company continues to operate in full compliance with the MATS rule. On December 15, 2015, the appellate court agreed to keep the current MATS rule in place while the agency completes the supplemental cost analysis ordered by the Court.

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 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 regarding SO3 emissions from the EPA. The total investment is estimated to be between $75 million and $85 million, roughly half of which has been spent to control mercury in both air and water emissions, and the remaining investment has been made to address the issues raised in the NOV.

In March 2015, the Company was notified that certain parties had filed a Notice of Appeal with the Indiana Court of Appeals in response to the IURC's Order. In June 2015, Joint Appellants’ Citizens Action Coalition of Indiana, Inc., Sierra Club, Inc., and Valley Watch, Inc. (the appellants) filed a brief which challenged the sufficiency of the findings in the IURC's January Order approving the Company’s investments and proposed accounting treatment in terms of whether that Order made certain findings required by statute. On October 29, 2015, the Indiana Court of Appeals issued its opinion affirming the IURC’s findings with regard to equipment required to comply with MATS and certain national pollutant discharge elimination system rules (approximately $35 million). The Court remanded the case back to the IURC so that it can make the findings required by statute with regard to equipment required by the NOV (approximately $40 million). On February 12, 2016, the appellants filed a petition to reopen the evidentiary record in the case in order to submit additional evidence. The Company has opposed the motion and believes the IURC already has a sufficient record in this case. As it pertains to the equipment requirement required by the NOV, given the Commission’s previous approval of this project, the Company believes the Commission will make these findings and issue a new order in support of the project.

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. The EPA is expected to make final determinations as to whether a region is in attainment for the new NAAQS in 2018 based upon monitoring data from 2014-2016. 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.

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, in which 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 is currently working with the state of Indiana on voluntary measures that the Company may take 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.

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 Company will continue to reuse a majority of its ash. Legislation is currently being considered 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. Opening briefs were filed by those parties in December of 2015, with full briefing not expected to be complete until May 2016.

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, the Company prepared preliminary cost estimates to retire the ash ponds at the end of their useful lives based on interpretation of the available closure alternatives contemplated in the final rule that 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. At this time the Company does not believe that these rules are applicable to its Warrick generating unit, as this unit is part of a larger generating station that predominantly serves an adjacent industrial facility. The Company continues to refine the assumptions, engineering analyses and resulting cost estimates. Further analysis and the refinement of assumptions may result in estimated costs that could be significantly in excess of the current range of $35 million to $80 million.

At September 30, 2015, the Company recorded an approximate $25 million asset retirement obligation (ARO). The recorded ARO reflected the present value of the approximate $35 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.

Effluent Limitation Guidelines (ELGs)
Under the Clean Water Act, the EPA sets technology-based guidelines for water discharges from new and existing 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 within the 2018-2023 time frame. Current wastewater discharge permits for the Brown and Culley power plants expire in October and December 2016, respectively. The Company is working with the State on permit renewals which will include a compliance schedule for ELGs. In no event will compliance with the ELGs be required prior to November 2018. The ELGs work in tandem with the recently released 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.

Cooling Water Intake Structures
Section 316(b) of the Clean Water Act requires that 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. To comply, the Company believes that capital investments will likely be in the range of $4 million to $8 million.

Climate Change

On August 3, 2015, the EPA released its final Clean Power Plan (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 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 it 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 the State of 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. The stay will remain in place while the lower court concludes its review, with oral arguments to be heard in June 2016 under the existing accelerated schedule. Among other things, the stay is anticipated to delay the requirement to submit a final SIP by the September 2016 deadline. Apart from the delay, the Court's action creates additional uncertainty as to the future of the rule and presents further challenges as the Company proceeds with its integrated resource planning process later this year.

In the event that 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 the State of Indiana will file a SIP has yet to be finally determined. Pending that determination, the electric utilities in Indiana are working with the state's designated agency to analyze various compliance options for consideration and possible integration into a state plan submittal.

Indiana is the 5th largest carbon emitter in the nation in tons of CO2 produced from electric generation. In 2013, Indiana's electric utilities generated 105.6 million tons of CO2. The Company's share of that total was 6.3 million, or less than 6 percent. From 2005 to 2014, the Company's emissions of CO2 have declined 27 percent (on a tonnage basis). These reductions have come from 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. 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 clean energy sources due to the long-term wind contracts and landfill gas investment. See further details on these clean energy sources in Item 1. With respect to CO2 emission rate, since 2005 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 the State's average CO2 emission rate of 1,923 lbs CO2/MWh. The Company plans to consider these reductions in CO2 emissions and renewable generation when working 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 State of Indiana to assess the final rule and to develop a plan that is the least cost to its customers.

While the Company cannot reasonably estimate the total cost to comply with the CCR, ELG and CPP regulations at this time, the Company is exploring various compliance options ranging from continued compliance to retirement of units. The cost of compliance with these new regulations could be significant. The Company believes that such compliance costs would be considered a federally mandated cost of providing electricity, and therefore, should be recoverable from customers through Senate Bill 251 as referenced above, Senate Bill 29, which was used by the Company to recover its initial pollution control investments, or through other forms of rate recovery. These compliance alternatives, including the impact on customer rates, will be fully considered as part of the Company’s public integrated resource planning process to be conducted in 2016.

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 $43.4 million ($23.2 million at Indiana Gas and $20.2 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 to date approximately $14.8 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, 2015 and December 31, 2014, approximately $3.3 million and $3.6 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

21. Fair Value Measurements

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

	At December 31,			
	2015		2014	
(In millions)	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	$1,795.8	$1,909.5	$1,577.3	$1,754.5
Short-term borrowings & notes payable	14.5	14.5	156.4	156.4
Cash & cash equivalents	74.7	74.7	86.4	86.4

For the balance sheets presented, 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 long-term debt are generally recovered in customer rates over the life of the refunding issue or over a 15-year period. Accordingly, any reacquisition would not be expected to have a material effect on the Company's results of operations.

Because of the nature of certain other investments and lack of a readily available market, it is not practical to estimate the fair value of these financial instruments at specific dates without considerable effort and cost. At December 31, 2015 and 2014, the fair value for these financial instruments was not estimated. The carrying value of these investments at December 31, 2015 and 2014 was approximately $16.1 million and $10.4 million respectively. The increase in carrying value from December 31, 2014 is primarily related to a debt security and note received from the sale of a commercial real estate investment in June 2015.

22. Segment Reporting

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

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

The Nonutility Group has historically reported five operating segments: Infrastructure Services, Energy Services, Coal Mining, Energy Marketing, and Other Businesses. Energy Services provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects. The Infrastructure Services segment provides underground pipeline construction and repair services for customers that include Vectren Utility Holdings' utilities. Fees incurred by Vectren Utility Holdings and its subsidiaries for these pipeline construction and repair services totaled $109.5 million in 2015, $94.0 million in 2014, and $54.2 million in 2013.

In its 2015 periodic reports, the 2014 results for the Coal Mining segment include the results of Vectren Fuels through August 29, 2014 when it exited the coal mining business through the sale of Vectren Fuels (see Note 6 for more details of this transaction). Additionally, ProLiance exited the energy marketing business in 2013. The Company reports the Energy Marketing segment information for 2013, which is inclusive of the Company's share of the loss from operations and its share of the loss on sale as recorded by ProLiance Energy. Assets related to the investment in ProLiance Holdings, LLC as described in Note 7 are reported in Other Businesses.

Corporate and Other includes unallocated corporate expenses such as advertising and certain charitable contributions, among other activities, that benefit the Company’s other operating segments. Total assets in all periods presented reflect the retrospective impacts of the adoption in 2015 of ASU 2015-17, Balance Sheet Classification of Deferred Taxes. Net income is the measure of profitability used by management for all operations. Information related to the

Company's business segments is summarized as follows:

104

	Year Ended December 31,		
(In millions)	2015	2014	2013
Revenues			
Utility Group			
Gas Utility Services	$792.6	$944.6	$810.0
Electric Utility Services	601.6	624.8	619.3
Other Operations	40.7	38.3	38.1
Eliminations	(40.4)	(38.0)	(37.8)
Total Utility Group	1,394.5	1,569.7	1,429.6
Nonutility Group			
Infrastructure Services	843.3	779.0	783.5
Energy Services	199.9	129.8	91.3
Coal Mining	—	234.3	292.8
Total Nonutility Group	1,043.2	1,143.1	1,167.6
Eliminations, net of Corporate & Other Revenues	(3.0)	(101.1)	(106.0)
Consolidated Revenues	$2,434.7	$2,611.7	$2,491.2
Profitability Measures - Net Income			
Utility Group Net Income			
Gas Utility Services	$64.4	$57.0	$55.7
Electric Utility Services	82.6	79.7	75.8
Other Operations	13.9	11.7	10.3
Total Utility Group Net Income	160.9	148.4	141.8
Nonutility Group Net Income (Loss)			
Infrastructure Services	29.7	43.1	49.0
Energy Services	7.3	(3.2)	1.0
Coal Mining	—	(21.1)	(16.0)
Energy Marketing	—	—	(37.5)
Other Businesses	(0.7)	(0.8)	(1.0)
Total Nonutility Group Net Income (Loss)	36.3	18.0	(4.5)
Corporate & Other Net Income (Loss)	0.1	0.5	(0.7)
Consolidated Net Income	$197.3	$166.9	$136.6

	Year Ended December 31,		
(In millions)	2015	2014	2013
Amounts Included in Profitability Measures			
Depreciation & Amortization			
Utility Group			
Gas Utility Services	$98.6	$93.3	$90.5
Electric Utility Services	85.6	85.7	84.0
Other Operations	24.6	24.1	21.9
Total Utility Group	208.8	203.1	196.4
Nonutility Group			
Infrastructure Services	44.5	36.2	28.8
Energy Services	2.7	3.9	1.7
Coal Mining	—	29.9	50.8
Other Businesses	0.3	0.3	0.1
Total Nonutility Group	47.5	70.3	81.4