VECTREN CORP
Form 10-K
February 17, 2015

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, 2014
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, 2014, was $3,496,151,448.

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	82,593,724	January 30, 2015
Class	Number of Shares	Date

Documents Incorporated by Reference

Certain information in the Company's definitive Proxy Statement for the 2015 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	MDth / MMDth: thousands / millions of dekatherms
ASC: Accounting Standards Codification	MISO: Midcontinent Independent System Operator
BTU / MMBTU: British thermal units / millions of BTU	MCF / BCF: thousands / billions of cubic feet
DOT: Department of Transportation	MW: megawatts
EPA: Environmental Protection Agency	MWh / GWh: megawatt hours / thousands of megawatt hours (gigawatt hours)
FASB: Financial Accounting Standards Board	NERC: North American Electric Reliability Corporation
FERC: Federal Energy Regulatory Commission	OCC: Ohio Office of the Consumer Counselor
IDEM: Indiana Department of Environmental Management	OUCC: Indiana Office of the Utility Consumer Counselor
IURC: Indiana Utility Regulatory Commission	PUCO: Public Utilities Commission of Ohio
IRC: Internal Revenue Code	Throughput: combined gas sales and gas transportation volumes
Kv: Kilovolt GAAP: Generally Accepted Accounting Principles	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: Robert L. Goocher 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), Southern Indiana Gas and Electric Company (SIGECO), 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 (Energy Act). Vectren was incorporated under the laws of Indiana on June 10, 1999.

Indiana Gas provides energy delivery services to approximately 575,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 143,000 electric customers and over 110,000 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 313,000 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 through the sale of Vectren Fuels. 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 are reflected in Other Businesses. Enterprises has other legacy businesses that have investments in energy-related opportunities and services, real estate, and a leveraged lease, 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, 2014, the Company had $5.2 billion in total assets, with $4.4 billion (85 percent) attributed to the Utility Group, and $0.8 billion (15 percent) attributed to the Nonutility Group. Net income for the year ended December 31, 2014, was $166.9 million, or $2.02 per share of common stock, with net income of $148.4 million attributed to the Utility Group, $18.0 million attributed to the Nonutility Group, and $0.5 million attributed to Corporate and Other. Net income for the year ended December 31, 2013, was $136.6 million, or $1.66 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 to west central Ohio. 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/or 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, 2014, the Company supplied natural gas service to approximately 1,011,100 Indiana and Ohio customers, including 924,000 residential, 85,400 commercial, and 1,700 industrial and other contract customers. Average gas utility customers served were approximately 998,200 in 2014, 992,100 in 2013, and 986,100 in 2012.

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 239.2 MMDth for the year ended December 31, 2014. Gas sold and transported to residential and commercial customers was 122.6 MMDth representing 51 percent of throughput. Gas transported or sold to industrial and other contract customers was 116.6 MMDth representing 49 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, 2014, gas utility revenues were approximately $944.6 million, of which residential customers accounted for 68 percent and commercial accounted for 24 percent. Industrial and other contract customers accounted for 8 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 also enter into short term and long term contracts with third party suppliers to ensure availability of gas. 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 of the net assets of its energy marketing business, ProLiance Energy, LLC (ProLiance Energy) (See the discussion of ProLiance below and Note 7 in the Company's Consolidated

Financial Statements included in Item 8). During 2014, the Company, through its utility subsidiaries, purchases all of its gas supply from third parties and 84 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 2014, Utility Holdings purchased 87.9 MMDth volumes of gas at an average cost of $5.42 per Dth inclusive of demand charges. The average cost of gas per Dth purchased for the previous four years was $4.60 in 2013, $4.47 in 2012, $5.30 in 2011, and $5.99 in 2010.

Electric Utility Services

At December 31, 2014, the Company supplied electric service to approximately 143,300 Indiana customers, including approximately 124,600 residential, 18,500 commercial, and 200 industrial and other customers. Average electric utility customers served were approximately 142,900 in 2014, 142,300 in 2013, and 141,700 in 2012.

The principal industries served include polycarbonate resin (Lexan®) and plastic products; aluminum smelting and recycling; aluminum sheet 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, 2014, retail electricity sales totaled 5,589.5 GWh, resulting in revenues of approximately $571.9 million. Residential customers accounted for 37 percent of 2014 revenues; commercial 27 percent; industrial 35 percent; and other 1 percent. In addition, in 2014 the Company sold 651.1 GWh through wholesale activities principally to the MISO. Wholesale revenues, including transmission-related revenue, totaled $52.9 million in 2014.

System Load

Total load for each of the years 2010 through 2014 at the time of the system summer peak, and the related reserve margin, is presented below in MW.

Date of summer peak load	8/27/2014	8/30/2013	7/24/2012	7/21/2011	8/4/2010
Total load at peak	1,095	1,102	1,259	1,220	1,275
Generating capability	1,298	1,298	1,298	1,298	1,298
Firm purchase supply	38	38	136	136	136
Interruptible contracts & direct load control	71	48	60	60	62
Total power supply capacity	1,407	1,384	1,494	1,494	1,496
Reserve margin at peak	22 %	25 %	19 %	22 %	17 %

The winter peak load for the 2013-2014 season of approximately 953 MW occurred on January 6, 2014. The prior year winter peak load for the 2012-2013 season was approximately 832 MW, occurring on February 1, 2013.

Generating Capability
Installed generating capacity as of December 31, 2014, was rated at 1,298 MW. Coal-fired generating units provide 1,000 MW of capacity, natural gas or oil-fired turbines used for peaking or emergency conditions provide 295 MW, and a landfill gas electric generation project provides 3 MW. Electric generation for 2014 was fueled by coal (98 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 5,546 GWh in 2014. 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 2.9 million tons were purchased for generating electricity during 2014, of which approximately 64 percent was supplied by Vectren Fuels, previously the Company's wholly owned subsidiary that was sold on August 29, 2014. This compares to 1.9 million tons and 2.1 million tons purchased in 2013 and 2012, respectively. The utility's coal inventory was approximately 600 thousand tons and 300 thousand tons at December 31, 2014 and 2013, respectively.

Coal Purchases
The average cost of coal per ton purchased and delivered for the last five years was $55.18 in 2014, $58.38 in 2013, $68.65 in 2012, $75.04 in 2011, and $70.47 in 2010. 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. Those contracts were submitted to the IURC for review as part of the 2014 annual sub docket proceeding. In December 2014, the Commission determined that the terms of the coal contracts are reasonable. The annual sub docket proceeding is no longer required.

On December 5, 2011 within the quarterly FAC filing, SIGECO submitted a joint proposal with the OUCC to reduce its fuel costs billed to customers by accelerating into 2012 the impact of lower cost coal under new term contracts effective after 2012. The cost difference was deferred to a regulatory asset and is being recovered over a six-year period without interest beginning in 2014. The IURC approved this proposal on January 25, 2012, with the reduction to customer's rates effective February 1, 2012. See "Electric Rate and Regulatory Matters" in Item 8 regarding coal procurement procedures and electric fuel cost reductions.

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 167 GWh from OVEC in 2014.

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 2014, the Company purchased approximately 58 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 2014, the Company purchased 147 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 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 2014, in hours when purchases from the MISO were in excess of generation sold to the MISO, the net purchases were 490 GWh. During 2014, in hours when sales to the MISO were in excess of purchases from the MISO, the net sales were 651 GWh.

Capacity Purchase
In May 2008, the Company executed a MISO capacity purchase from Sempra Energy Trading, LLC to purchase 100 MW of name plate capacity from its generating facility in Dearborn, Michigan. The term of the contract began January 1, 2010 and expired on December 31, 2012. The Company has not replaced this contract.

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 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

The utility industry has undergone structural changes for several years, resulting in increasing competitive pressures faced by electric and gas utility companies. Currently, several states have passed legislation allowing electricity customers to choose their electricity supplier in a competitive electricity market and several other states have considered such legislation. At the present time, Indiana has not adopted such legislation. Ohio regulation allows gas customers to choose their commodity supplier. The Company implemented a choice program for its gas customers in Ohio in January 2003. Substantially all of VEDO's customers receive gas from third-party suppliers and at December 31, 2014, approximately 128,000 customers in the Company’s Ohio service territory had selected their supplier. In addition, VEDO’s service territory continues to transition toward exiting the merchant function. Margin earned for transporting natural gas to those customers, who have purchased natural gas from another supplier, is generally the same as that earned by selling gas under Ohio tariffs. Indiana has not adopted any regulation requiring gas choice; however, the Company operates under approved tariffs permitting certain industrial and commercial large volume customers to choose their commodity supplier.

Increased competition, including those from cogeneration, solar, and other renewables opportunities for customers, create competitive pressures. In this regard, the deployment and commercialization of disruptive 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 disruptive technologies, this may have an adverse effect on the Company’s financial condition and results of operations.

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, the Company was involved in nonutility activities 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) 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 $779 million in gross revenues for 2014, compared to $784 million in 2013 and $664 million in 2012.

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 fixed price contracts. Using blanket contracts, customers are not contractually committed to specific volumes or specific time frames for project completion. These contracts are typically awarded on an annual basis. Under fixed price 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, 2014, Infrastructure Services had an estimated backlog of blanket contracts of $500 million and a backlog of fixed price contracts of $125 million, for a total backlog of $625 million. The estimated backlog at December 31, 2013 was $460 million for blanket contracts and $75 million for fixed price 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.

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. 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 to reduce 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 $130 million in 2014, compared to $91 million in 2013 and $118 million in 2012. ESG’s backlog at December 31, 2014 was $144 million, compared to $72 million at December 31, 2013.

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.

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, real estate, and a leveraged lease, 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, 2014, the Company and its consolidated subsidiaries had approximately 5,500 employees. Of those employees, 700 are subject to collective bargaining arrangements negotiated by Utility Holdings and 3,100 are subject to collective bargaining arrangements negotiated by Infrastructure Services.

Utility Holdings

In 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.

In December 2012, the Company reached a three-year agreement with Local 175 of the Utility Workers Union of America. The labor agreement was retroactively effective to November 1, 2012 and ends October 31, 2015. This labor agreement relates to employees of VEDO.

In September 2012, the Company reached a three-year agreement with Local 135 of the Teamsters, Chauffeurs, Warehousemen, and Helpers Union, ending September 23, 2015. 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 2015 and 2016. 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

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 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 renewable energy expansion. It is also possible that unfavorable conditions could lead to reductions in the value of certain nonutility real estate and other 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, aluminum products, polycarbonate resin (Lexan®) and plastic products; gypsum products; electrical equipment, metal specialties, glass and steel finishing; aluminum smelting and recycling; pharmaceutical and nutritional products; gasoline and oil products; ethanol; and coal mining.

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, 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 disruptive 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 disruptive 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. 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, Department of Energy (DOE), Occupational Safety and Health Administration (OSHA), and 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, PUCO, and 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 is currently considering revisions to 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 certain of the 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 (SO2), 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.

Climate Change and Renewable Energy Considerations
On June 2, 2014, the EPA proposed its rule for states to regulate carbon dioxide (CO2) emissions from existing electric generating units. The rule, when final will require states to adopt plans that reduce CO2 emissions by 30 percent from 2005 levels by 2030. Despite having just been recently proposed and not expected to be finalized until summer of 2015, legal challenges to the EPA's proposal have begun. Similarly, in the President's Climate Action Plan

on methane emissions released in March of 2014, new actions were outlined to require 40 percent to 45 percent reduction in methane emissions from upstream sources, specifically targeting new and modified oil and natural gas production wells. Downstream sources, such as local distribution companies, will be encouraged to participate in a new voluntary methane emissions monitoring and reduction program. If these regulations are finalized by the EPA, or if legislation requiring reductions in CO2 and other GHGs or legislation mandating a renewable energy portfolio standard is adopted, such regulation could 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 emissions. However, these compliance cost estimates are based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. At this time and in the absence of final legislation or regulatory mandates, compliance costs and other effects associated with reductions in greenhouse gas 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. In 2013 and 2014, there was 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 upon regulatory discretion, and 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. Both Indiana and Ohio have passed laws allowing utilities to recover at least some 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.

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 a joint complaint filed against MISO and various MISO transmission owners, including the Company. The FERC has yet to rule on the case 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.

Wholesale power marketing activities may add volatility to earnings.

The Company's regulated electric utility engages in wholesale power marketing activities that primarily involve the offering of utility-owned or contracted generation into the MISO hourly and real time markets. As part of these strategies, the Company may also execute energy contracts that are integrated with portfolio requirements around power supply and delivery. Presently, margin earned from these activities above or below $7.5 million per year is shared evenly with customers. These earnings from wholesale marketing activities may vary based on fluctuating prices for electricity and the amount of electric generating capacity or purchased power available beyond that needed to meet firm service requirements. In addition, this earnings sharing approach may be modified in future regulatory proceedings.

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 volatile 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. State and/or federal regulation may require mandatory conservation measures, which would reduce the demand for energy products. 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; 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; potential legislation or regulations that may limit CO_2 and other greenhouse gases emissions; operating accidents that may require environmental remediation; failure to properly construct pipeline infrastructure; 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; environmental or cybersecurity regulations, and changing market conditions.

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/or cash flows. Changes in legislation and regulations impacting the industries in which the customers served by Infrastructure Services operate could impact operating results. Other risks include, but are not limited to: the effects of weather; failure to properly estimate the cost to construct projects; the inability to attract and retain qualified employees; cancellation of projects by customers and/or reductions in the scope of the projects; credit worthiness of customers; inability to obtain materials and equipment required to perform services from suppliers and manufacturers; and changing market conditions, including changes in the market prices of oil and natural gas that would affect the demand for infrastructure construction.

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, 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: failure to properly estimate the cost to construct projects; the inability to attract and retain qualified employees; risks associated with projects owned or operated; cancellation of projects by customers and/or reductions in the scope of the projects; credit worthiness of customers; and changing market conditions.

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 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 weather; 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/or type of customers in the Company's service territories; the demand for energy resulting in the need for additional investment in generation assets or the need to retire current infrastructure that is no longer required; an increase to the cost of providing service; 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.

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.

Regulations related to the use of derivatives that became law in 2010 under the Dodd-Frank Wall Street Reform and Consumer Protection Act continue to evolve and their ultimate application remains uncertain. Depending on the continued evolution of the regulations adopted by the Commodity Futures Trading Commission (CFTC) and other agencies, the Company may be required to post additional collateral with dealer counterparties for commitments and interest rates, physical or financial commodity derivative transactions and report or otherwise disclose such activity to dealer counterparties or other agencies. The law provides for an exception from these clearing and cash collateral requirements for commercial end-users. Requirements to post collateral could limit cash for investment and for other corporate purposes or could increase debt levels and resulting interest expense. In addition, a requirement for counterparties to post collateral could result in additional costs associated with executing transactions, thereby decreasing profitability. An increased collateral requirement could also reduce the Company's ability to execute derivative transactions to reduce commodity price and interest rate uncertainty and to protect cash flows. The regulations may also limit the pool of potential counterparties and/or the liquidity in the respective markets for such transactions.

Significant rule-making by numerous governmental agencies, particularly the 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/or 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 one customer 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, acts of war, 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. 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 and systems to operate its generating facilities, engage in asset management activities, and process, transmit and store electronic information including customer and employee information. Security breaches of this information technology infrastructure could lead to system disruptions, 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 attract and retain qualified and diverse personnel; that it will be unable to effectively transfer the knowledge and expertise of an aging workforce to new personnel as those workers retire; that it will be unable to react to a pandemic illness; an overall migration to more defined contribution and high deductible employee benefit packages; and 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 our 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 to handle 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, bribery of foreign government officials, import-export control, 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.

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 145,500 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 13,100 miles of distribution and transmission mains, all of which are in Indiana except for pipeline facilities extending from points in northern Kentucky to points in southern Indiana so that gas may be transported to Indiana and sold or transported by Indiana Gas to ultimate customers in Indiana.

SIGECO owns and operates three active underground gas storage fields located in Indiana covering 6,100 acres of land with an estimated ready delivery from storage capability of 5.3 BCF of gas with maximum peak day delivery capabilities of 88,000 MCF per day. In addition to its company owned storage delivery capabilities, SIGECO has contracted for 0.4 BCF of interstate 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 contracted for 11.8 BCF of natural gas delivery service with a maximum peak day delivery capability of 246,100 MMBTU per day. While the Company still has title to this delivery capability, it has released it to those retail gas marketers now supplying VEDO’s customers with natural gas, and those suppliers are responsible for the demand charges. VEDO’s gas delivery system includes 5,500 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, 2014, was rated at 1,298 MW. SIGECO's coal-fired generating facilities are the Brown Station with two units of 490 MW of combined capacity, located in Posey County approximately eight miles east of Mt. Vernon, Indiana; the Culley Station with two units of 360 MW of combined capacity; and Warrick Unit 4 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; two Broadway Avenue Gas Turbines located in Evansville, Indiana with a combined capacity of 115 MW (Broadway Avenue Unit 1, 50 MW and Broadway Avenue Unit 2, 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 six gas turbines is 295 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 37 substations with an installed capacity of 4,722 megavolt amperes (Mva). The electric distribution system includes 4,560 circuit miles of lower voltage overhead lines and 402 trench miles of conduit containing 2,325 circuit miles of underground distribution cable. The distribution system also includes 95 distribution substations with an installed capacity of 2,995 Mva and 52,267 distribution transformers with an installed capacity of 2,330 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. 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 8,000 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 one of 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 in effect prior to the formation of Vectren.

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 2014 and 2013, 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	Common Stock Price Range	
		Dividend	High	Low
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
2013				
	First Quarter	$0.355	$35.45	$29.47
	Second Quarter	0.355	37.57	32.15
	Third Quarter	0.355	37.88	31.83
	Fourth Quarter	0.360	35.63	32.45

On January 29, 2015 the board of directors declared a dividend of $0.38 per share, payable on March 2, 2015, to common shareholders of record on February 13, 2015.

As of January 30, 2015, there were 8,347 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, 2014.

Dividend Policy

Common stock dividends are payable at the discretion of the board of directors, out of legally available funds. The Company’s policy has historically been to distribute approximately 65 percent of earnings, now targeting 60 percent on a go forward basis. On an annual basis, this percentage has varied and could continue to vary due to short-term earnings volatility. The Company has increased its dividend for 55 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.

21

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)	2014	2013	2012	2011	2010
Operating Data:					
Operating revenues	$2,611.7	$2,491.2	$2,232.8	$2,325.2	$2,129.5
Operating income	$314.5	$333.6	$352.5	$370.0	$316.8
Net income	$166.9	$136.6	$159.0	$141.6	$133.7
Average common shares outstanding	82.5	82.3	82.0	81.8	81.2
Fully diluted common shares outstanding	82.5	82.4	82.1	81.8	81.3
Basic earnings per share on common stock	$2.02	$1.66	$1.94	$1.73	$1.65
Diluted earnings per share on common stock	$2.02	$1.66	$1.94	$1.73	$1.64
Dividends per share on common stock	$1.460	$1.425	$1.405	$1.385	$1.365
Balance Sheet Data:					
Total assets	$5,162.3	$5,102.6	$5,089.1	$4,878.9	$4,764.2
Long-term debt, net	$1,407.3	$1,777.1	$1,553.4	$1,559.6	$1,435.2
Common shareholders' equity	$1,606.6	$1,554.3	$1,526.1	$1,465.5	$1,438.9

Results include the loss on disposition and operating results of Coal Mining in 2014 and the loss on disposition and operating losses attributable to the Company's investment in ProLiance in 2013.

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 since each operates independently requiring distinct competencies and business strategies, offers different energy and energy related products and services, and experiences different opportunities and risks.

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 the 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 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 charitable contributions, among other activities.

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

Results for the year ended December 31, 2014 were earnings of $166.9 million, or $2.02 per share, compared to earnings of $136.6 million, or $1.66 per share for the year ended December 31, 2013 and $159.0 million, or $1.94 per share for the year ended December 31, 2012. 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 through the sale of Vectren Fuels. In June 2013, ProLiance Holdings, LLC (ProLiance or ProLiance Holdings) 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 are reflected in the Other Businesses segment. In 2014, excluding the loss on the disposition and year to date 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 losses 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 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. 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. Results from the Coal Mining segment (Coal Mining) for the year ended December 31, 2014, inclusive of the approximate $20 million loss on the sale, was a loss of $21.1 million, net of tax, compared to losses of $16.0 million and $3.5 million for the years ended December 31, 2013 and 2012, respectively.

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. Operating losses for ProLiance totaled $17.6 million, net of tax, for the year ended December 31, 2012. 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 is reflected in the Other Businesses segment in 2013.

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 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, 2014, 2013, and 2012 follow:

	Year Ended December 31,		
(In millions, except per share data)	2014	2013	2012
Net income (loss), excluding Coal Mining & ProLiance results*	$188.0	$174.1	$159.0
Attributed to:			
Utility Group	$148.4	$141.8	$138.0
Nonutility Group, excluding Coal Mining & ProLiance results*	39.1	33.0	21.7
Corporate & Other	0.5	(0.7)	(0.7)
Basic EPS, excluding Coal Mining & ProLiance results*	$2.28	$2.12	$1.94
Attributed to:			
Utility Group	$1.80	$1.72	$1.68
Nonutility Group, excluding Coal Mining & ProLiance results*	0.47	0.41	0.26
Corporate & Other	0.01	(0.01)	—

*Excludes Coal Mining results in 2014 and ProLiance results in 2013 - Years of Disposition

Utility Group
For the year ended December 31, 2014, the Utility Group earnings were $148.4 million, compared to $141.8 million in 2013 and $138.0 million in 2012. The improved results in 2014 are primarily driven by increased gas and electric margins partially offset by higher operating expenses from increased performance-based compensation expense and gas system maintenance resulting from the harsh winter in the first half of the year.

Gas utility services
The gas utility segment earned $57.0 million during the year ended December 31, 2014, compared to $55.7 million in 2013 and $60.0 million in 2012. The increased results in 2014 were due to increased customer margin from returns on the Ohio infrastructure replacement programs and small customer growth. This increase in margin 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. In 2013, as compared to 2012, increases in operating costs more than offset margin increases. The increased operating costs were primarily the result of the acceleration of maintenance projects that were completed in 2013 and increased depreciation expense.

Electric utility services
The electric operations earned $79.7 million during 2014, compared to $75.8 million in 2013 and $68.0 million in 2012. Improved 2014 results 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 related to electric conservation programs, which had an after tax favorable impact of $2.3 million. Results were also favorably impacted by increased deferral of interest on construction projects. 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 the current year.

Other utility operations

In 2014, earnings from other utility operations were $11.7 million, compared to $10.3 million in 2013 and $10.0 million in 2012. A lower income tax rate in 2014, primarily driven by 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.

Nonutility Group
Reported results for the Nonutility Group were earnings of $18.0 million in 2014, a loss of $4.5 million in 2013 and earnings of $21.7 million in 2012. 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 2014 were unfavorably impacted by decreased results from Infrastructure Services 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. Energy Services results in 2014 reflect a reduction in 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 due to the failure to meet certain earn out thresholds. These non-recurring earnings 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 also reflect losses at Coal Mining of $16.0 million in 2013 and $3.5 million in 2012 as well as losses of $17.6 million at ProLiance in 2012.

Dividends

Dividends declared for the year ended December 31, 2014 were $1.460 per share, compared to $1.425 per share in 2013 and $1.405 per share in 2012. In December 2014, the Company’s board of directors increased its quarterly dividend to $0.380 per share from $0.360 per share. The increase marks the 55th 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 and ProLiance in the respective years of disposition.

Management uses consolidated net income, consolidated earnings per share, and Nonutility Group net income, excluding the results from Coal Mining in 2014 and ProLiance in 2013, the years of disposition, 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) incurred to date. Management believes analyzing underlying and ongoing business trends is aided by the removal of Coal Mining and ProLiance results in the respective year of disposition and the rationale for using such non-GAAP measures is that, through the disposition of the Coal Mining segment and through the disposition by ProLiance Holdings of certain ProLiance Energy assets, the Company has now exited the coal mining and gas marketing businesses, and provides the best representation of the overall results of the ongoing operations.

A material limitation associated with the use of these measures is that the measures that exclude 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, the years of disposition, 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, but rather represent a direct equity interest in Vectren Corporation'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. Reconciliations of the non-GAAP measures to their most closely related GAAP measure of consolidated earnings per share are included throughout this discussion and analysis. The non-GAAP financial measures disclosed by the Company should not be considered a substitute for, or superior to, financial measures calculated in accordance with GAAP, and the financial results calculated in accordance with GAAP.

The following table reconciles consolidated net income, consolidated basic EPS, and Nonutility Group net income to those results excluding Coal Mining results in 2014 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 Results	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 Results	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 comprised 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 that provides natural gas distribution and transportation services to nearly two-thirds of Indiana and to west central Ohio and an electric transmission and distribution business, which 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)	2014	2013	2012
OPERATING REVENUES			
Gas utility	$944.6	$810.0	$738.1
Electric utility	624.8	619.3	594.9
Other	0.3	0.3	0.6
Total operating revenues	1,569.7	1,429.6	1,333.6
OPERATING EXPENSES			
Cost of gas sold	468.7	358.1	301.3
Cost of fuel & purchased power	201.8	202.9	192.0
Other operating	354.5	333.4	310.1
Depreciation & amortization	203.1	196.4	190.0
Taxes other than income taxes	60.2	57.2	53.4
Total operating expenses	1,288.3	1,148.0	1,046.8
OPERATING INCOME	281.4	281.6	286.8
Other income - net	16.8	10.5	8.0
Interest expense	66.6	65.0	71.5
INCOME BEFORE INCOME TAXES	231.6	227.1	223.3
Income taxes	83.2	85.3	85.3
NET INCOME	$148.4	$141.8	$138.0
CONTRIBUTION TO VECTREN BASIC EPS	$1.80	$1.72	$1.68

The Regulatory Environment

Gas and electric operations, 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), are regulated by the IURC. 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 specific bare steel and cast iron replacement programs in all natural gas service territories, and an expanded gas infrastructure replacement program in Indiana, 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. The implementation of these various mechanisms has allowed the Company to avoid regulatory proceedings to increase base rates since 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 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. The last time the Company was impacted by this earnings test was in the electric FAC in 2012.

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 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 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 revenues less Cost of gas sold)
Gas utility margin and throughput by customer type follows:

	Year Ended December 31,		
(In millions)	2014	2013	2012
Gas utility revenues	$944.6	$810.0	$738.1
Cost of gas sold	468.7	358.1	301.3
Total gas utility margin	$475.9	$451.9	$436.8
Margin attributed to:			
Residential & commercial customers	$347.4	$341.1	$333.9
Industrial customers	59.3	58.0	55.2
Other	11.1	9.7	9.5
Regulatory expense recovery mechanisms	58.1	43.1	38.2
Total gas utility margin	$475.9	$451.9	$436.8
Sold & transported volumes in MMDth attributed to:			
Residential & commercial customers	122.6	111.9	90.2
Industrial customers	116.6	111.7	105.8
Total sold & transported volumes	239.2	223.6	196.0

Gas Utility margins were $475.9 million for the year ended December 31, 2014, and compared to 2013, increased $24.0 million. With rate designs that substantially limit the impact of weather on margin, 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. However, colder weather did increase 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.

For the year ended December 31, 2013, gas utility margins increased $15.1 million compared to 2012. Customer margin increased approximately $8.7 million in 2013 from customer growth and returns generated on infrastructure replacement programs in Ohio. Heating degree days that were 103 percent of normal in Ohio and 102 percent of normal in Indiana during 2013, compared to 88 percent of normal in Ohio and 79 percent of normal in Indiana in 2012, had an approximate $0.8 million favorable impact on small customer margin. However, weather, which led to higher volumes, was the primary driver in the higher regulatory expense recovery margin, which increased $4.9 million compared to 2012.

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)	2014	2013	2012
Electric utility revenues	$624.8	$619.3	$594.9
Cost of fuel & purchased power	201.8	202.9	192.0
Total electric utility margin	$423.0	$416.4	$402.9
Margin attributed to:			
Residential & commercial customers	$260.8	$255.8	$255.8
Industrial customers	111.2	108.7	108.5
Other	5.5	4.8	1.6
Regulatory expense recovery mechanisms	11.6	10.5	4.9
Subtotal: retail	$389.1	$379.8	$370.8
Wholesale power & transmission system margin	33.9	36.6	32.1
Total electric utility margin	$423.0	$416.4	$402.9
Electric volumes sold in GWh attributed to:			
Residential & commercial customers	2,762.3	2,722.1	2,731.7
Industrial customers	2,804.6	2,735.2	2,710.5
Other customers	22.6	21.8	22.6
Total retail volumes sold	5,589.5	5,479.1	5,464.8

Retail
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 contributed increased margin of $3.9 million related to electric conservation programs compared to the prior year. 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.

In 2013, Electric retail utility margins were $379.8 million for the year ended December 31, 2013 and, compared to 2012, increased by $9.0 million. Cooling degree days in 2013 were 103 percent of normal compared to 130 percent of normal in 2012, resulting in lower small customer margin of $1.2 million, largely offset by an increase in customers. Large customer margins for 2013 were relatively flat when compared to 2012. Other margin was higher in 2013 by $3.2 million, due in part to $2.6 million in refunds to customers during 2012 resulting from statutory net operating income limits. Margin from regulatory expense recovery mechanisms increased $5.6 million in 2013 compared to 2012, driven by a corresponding increase in operating expenses associated with the electric state-mandated conservation programs.

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 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)	2014	2013	2012
MISO Transmission system margin	$26.1	$29.4	$26.4
MISO Off-system margin	7.8	7.2	5.7
Total wholesale margin	$33.9	$36.6	$32.1

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms, and other transmission system operations, totaled $26.1 million during 2014, compared to $29.4 million in 2013 and $26.4 million in 2012. Results in 2014 reflect lower returns on transmission investments due to a reserve recorded associated with a pending FERC ROE complaint. To date, the Company has invested $157.7 million in qualifying projects. The net plant balance for these projects totaled $143.6 million at December 31, 2014. 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. As mentioned above, the Company has established a reserve pending the outcome of this complaint. 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, 2014, margin from off-system sales was $7.8 million, compared to $7.2 million in 2013 and $5.7 million in 2012. 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 for the periods presented reflect the impact of that sharing. Off-system sales were 651.1 GWh in 2014, compared to 514.4 GWh in 2013, and 336.7 GWh in 2012. The increase in volumes sold for the years presented from the Company's primarily coal-fired generation result from lower costs to generate due to a decrease in coal prices.

Utility Group Operating Expenses

Other Operating

For the year ended December 31, 2014, Other operating expenses were $354.5 million, and compared to 2013, increased $21.1 million. Costs recovered directly in margin account for $12.4 million of the increase during the year. Excluding these pass through costs, other operating expenses increased $8.7 million in 2014, compared to 2013, primarily associated with 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 half of 2014.

For the year ended December 31, 2013, Other operating expenses increased $23.3 million compared to 2012. Excluding operating expenses recovered through margin, expenses increased $15.9 million, primarily associated with additional maintenance projects that were completed in 2013 of $7.8 million, increased energy delivery expenses of $2.2 million, and an increase in performance-based compensation of $4.1 million.

Depreciation & Amortization

For the year ended December 31, 2014, Depreciation and amortization expense was $203.1 million, compared to $196.4 million in 2013 and $190.0 million in 2012. Results in the periods presented reflect increased utility plant investments placed into service.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $3.0 million in 2014 compared to 2013 and increased $3.8 million in 2013 compared to 2012. The increase in the periods presented was primarily due to higher revenue taxes associated with increased consumption and higher gas costs. These taxes are primarily revenue-related taxes and are offset dollar-for-dollar with higher gas utility and electric utility revenues reflected in margin attributable to regulatory expense recovery mechanisms.

Other Income-Net
Other income-net reflects income of $16.8 million in 2014, compared to $10.5 million in 2013 and $8.0 million in 2012. Results include increased allowance for funds used during construction (AFUDC) of approximately $7.5 million in 2014 compared to 2013 and $1.9 million in 2013 compared to 2012. The higher AFUDC reflects an increased AFUDC rate as well as increased capital expenditures related to infrastructure replacement investments.

Interest Expense
For the year ended December 31, 2014, Interest expense was $66.6 million, compared to $65.0 million in 2013 and $71.5 million in 2012. The decrease in interest expense since 2012 is due to refinancing activity, yielding favorable interest rates. During 2013, the Utility Group issued $385.9 million in utility related long-term debt with a weighted average interest rate of 3.59 percent and retired $337.9 million of long-term debt that matured or was called for early redemption with a weighted average interest rate of 5.58 percent.

Income Taxes
For the year ended December 31, 2014, Utility Group federal and state income taxes were $83.2 million, compared to $85.3 million in both 2013 and 2012. The lower income tax rate in 2014 was primarily driven by the revaluation of Utility Group deferred income taxes related to the sale of Vectren Fuels, Inc. as well as a tax deduction for domestic production activity in 2014.

Gas Rate & Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement

The Company monitors and maintains its natural gas distribution system to ensure that 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 in both Indiana and Ohio were passed that 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, 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 and of the investment, as well as property taxes and operating expenses. The remaining 20 percent of project costs is 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. By allowing for the deferral of costs, such as depreciation, property taxes, and debt-related post in service carrying costs until recovery is approved by the Ohio Commission.

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 project to three years after being placed into service at SIGECO and four years after being placed into service at Indiana Gas. At December 31, 2014 and 2013, the Company has regulatory assets totaling $16.4 million and $12.1 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, discussed further below.

Requests for Recovery Under Indiana Regulatory Mechanisms
On August 27, 2014, the Commission issued an Order approving the Company’s seven-year capital infrastructure replacement and improvement plan, beginning in 2014, and the proposed accounting authority and recovery, pursuant to Senate Bill 251 and 560. 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 associated with pipeline safety rules, with 80 percent of the costs 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 update the seven-year capital investment plan annually, with detailed estimates provided for the upcoming calendar year. 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 Indiana Office of Utility Consumer Counselor (OUCC) filed a Notice of Appeal with the Indiana Court of Appeals in response to the IURC's Order. On January 28, 2015, the OUCC filed its appellate brief raising an issue regarding the treatment of retired assets within the recovery mechanism. An appeal was also filed in response to the IURC's Order in Northern Indiana Public Service Company's (NIPSCO) Senate Bill 560 electric infrastructure proceeding, pertaining to certain issues regarding the Commission's authority to approve NIPSCO's infrastructure plan. The outcome of neither appeal and the implications to the Company’s Order, if any, cannot be determined.

On January 14, 2015, the Commission issued an Order approving the Company’s initial request for recovery of the revenue requirement associated with capital investment and applicable operating costs through June 30, 2014 as part of its approved seven-year plan. As the next step of the recovery process, as outlined in the legislation, this Order initiates the rates and charges necessary to begin cash recovery of 80 percent of the revenue requirement, with the remaining 20 percent deferred for recovery in the Company's next rate cases. Also, consistent with the guidelines set forth in the original August 2014 Order, the Commission 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 cost increases. The updated plan reflects capital expenditures of approximately $900 million, an increase of $35 million from the previous plan and is inclusive of an estimated $30 million of economic development related expenditures, over the seven-year period beginning in 2014. The plan also includes approximately $15 million of annual operating costs associated with pipeline safety rules.

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 to be earned 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 $150.5 million. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $13.1 million and $9.3 million at December 31, 2014

and December 31, 2013, 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, subject to the graduated caps on the fixed DRR monthly charge applicable to residential and small general service customers approved in the Order. 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 May 1, 2014, the Company filed its annual request to adjust the DRR for recovery of costs incurred through December 31, 2013. On August 27, 2014 the PUCO issued an Order approving the Company’s revised DRR rates and charges, effective September 1, 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 three-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, 2014, 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, 2014, which covers the Company’s capital expenditure program through calendar year 2014. During 2014 and 2013, these approved capital expenditure programs under House Bill 95 generated Other income associated with the debt-related post-in-service carrying costs totaling $3.9 million and $2.2 million, respectively. Deferral of depreciation and property tax expenses related to these programs in 2014 and 2013 totaled $3.1 million and $1.7 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 has modified its position in testimony filed on November 5, 2014, and now suggests a reduced disallowance of $3 million. The Commission has moved this specific issue to a sub-docket proceeding, and based on the procedural schedule, an order is expected later in 2015. The Company believes that the costs are either recoverable in its GCA, or that if the incentive mechanism calculation is found to create a credit due to customers, any such outcome would be funded by its supply administrator. The administrator has intervened and filed testimony in the proceeding.

Indiana Gas & SIGECO Gas Decoupling Extension Filing

On August 18, 2011, the IURC issued an Order granting the extension of the current decoupling mechanism in place at both Indiana gas companies and recovery of new conservation program costs through December 2015. The Order provides that the companies must submit an extension proposal no later than March 1, 2015. The Companies have reached an agreement in principle with the OUCC to extend the decoupling mechanism through 2020. The final settlement will be filed for approval by the Commission by March 1, 2015.

Electric Rate and Regulatory Matters

SIGECO Electric Environmental Compliance Filing

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 mercury and air toxin standards effective in 2015 and to address an outstanding Notice of Violation (NOV) from the EPA. The total investment is estimated to be between $80 and $90 million, roughly half of which will be made to control mercury in both air and water emissions, and the remaining investment will be made to address the issues raised in the NOV proceeding on the increase in sulfur trioxide emissions. Although the Company and the Commission acknowledge that these investments are recoverable as clean coal technology under Senate Bill 29 and federal mandated investment under Senate Bill 251, the Order approves the Company's request for deferred accounting treatment in lieu of timely recovery to avoid immediate customer bill impacts. 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 expected to occur in 2015 and 2016.

Coal Procurement Procedures
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. Those contracts were submitted to the IURC for review as part of the 2014 annual sub docket proceeding. In December 2014, the Commission determined that the terms of the coal contracts are reasonable. The annual sub docket proceeding is no longer required.

On December 5, 2011 within the quarterly FAC filing, SIGECO submitted a joint proposal with the OUCC to reduce its fuel costs billed to customers by accelerating into 2012 the impact of lower cost coal under new term contracts effective after 2012. The cost difference was deferred to a regulatory asset and is being recovered over a 6 year period without interest beginning in 2014. The IURC approved this proposal on January 25, 2012, with the reduction to customer's rates effective February 1, 2012. The total balance deferred for recovery through the Company's FAC, which began February 2014, was $42.4 million, of which $35.3 million remains as of December 31, 2014.

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; and 4) deferral of lost margin up to $3 million in 2012 and $1 million in 2011 associated with small customer DSM programs for subsequent recovery under a tracking mechanism to be proposed by the Company. On June 20, 2012, the IURC issued an Order approving a small customer lost margin recovery mechanism, inclusive of all previous deferrals. This mechanism is an alternative to the electric decoupling proposal that was denied by the IURC in the Company's last base rate proceeding. For the twelve months ended December 31, 2014 and December 31, 2013, the Company recognized Electric utility revenue of $8.7 million and $5.0 million, respectively, associated with this approved lost margin recovery mechanism.

On March 28, 2014, Senate Bill 340 was signed into law. This legislation ended electric DSM programs on December 31, 2014 that have been conducted to meet the energy savings requirements established in the Commission's December 2009 Order. 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. Indiana's governor has requested that the Commission make new recommendations for energy efficiency programs to be proposed for 2015 and beyond, and has also asked the legislature to consider further legislation requiring some level of utility sponsored energy efficiency programs. The Company filed a request for Commission approval of a new portfolio of DSM programs on May 29, 2014 to be offered in 2015. On October 15, 2014, the Commission issued an Order approving a Settlement between the OUCC and the Company regarding the new portfolio of DSM programs effective January 2015.

FERC Return on Equity (ROE) Complaint

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 MISO and various MISO transmission owners, including SIGECO. The joint parties seek to reduce the 12.38 percent return on equity 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. The MISO transmission owners filed their response to the complaint on January 6, 2014, opposing any change to the return. As of December 31, 2014, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $143.6 million at December 31, 2014.

This joint complaint is 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 methodology set out in its June 19, 2014 decision.
In addition to the NETO ruling, the FERC acknowledged that the pending complaint raised against the MISO transmission owners is reasonable, and ordered the initiation of a formal settlement discussion, mediated by a FERC appointed judge, in November 2014. As of January 2015, a settlement was not reached, and the case will move to a formal evidentiary hearing before the FERC. A procedural schedule was set on January 22, 2015, which will define a targeted date of final resolution from the FERC. An initial decision is expected later in 2015, but the timing of the final order from the FERC is unknown at this time. The Company has established a reserve pending the outcome of this complaint.

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 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.

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/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.

Indiana Senate Bill 251
Indiana Senate Bill 251 is also applicable to federal environmental mandates impacting SIGECO electric operations. The Company continues with its ongoing evaluation of the impact Senate Bill 251 may have on its operations, including applicability of the stricter regulations the EPA is currently considering involving air quality, fly ash disposal, cooling tower intake facilities, waste water discharges, and greenhouse gases. These issues are further discussed below.

Air Quality
Cross-State Air Pollution Rule
In July 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR). CSAPR was the EPA’s response to the US Court of Appeals for the District of Columbia’s (the Court) remand of the Clean Air Interstate Rule (CAIR). CAIR was originally established in 2005 as an allowance cap and trade program that required reductions from coal-burning power plants for NOX emissions beginning January 1, 2009 and SO2 emissions beginning January 1, 2010, with a second phase of reductions in 2015. In an effort to address the Court’s finding that CAIR did not adequately ensure attainment of pollutants in certain downwind states due to unlimited trading of SO2 and NOX allowances, CSAPR

reduced the ability of facilities to meet emission reduction targets through allowance trading. CSAPR reductions were to be achieved with initial step reductions beginning January 1, 2012, and final compliance to be achieved in 2014. After a series of legal challenges, the United States Supreme Court upheld CSAPR in April 2014, and the EPA finalized a new deadline schedule for entities that must comply, with CSAPR's first phase caps starting in 2015 and 2016, and the second phase in 2017. The Company is in full compliance with all requirements of CSAPR.

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. Reductions are to be achieved within three years of publication of the final rule in the Federal Register (April 2015). The EPA did not grant blanket compliance extensions but asserted that states have broad authority to grant one year extensions for individual electric generating units where potential reliability impacts have been demonstrated. Legal challenges to the MATS Rule continue. In July, a coalition of twenty-one states, including Indiana, filed a petition for certiorari with the U.S. Supreme Court seeking review of the decision of the appellate court. On November 25, 2014, the U.S. Supreme Court agreed to hear the case, with a decision expected later in 2015.

Notice of Violation for A.B. Brown Power Plant
The Company received a notice of violation (NOV) from the EPA in November 2011 pertaining to its A.B. Brown generating station. The NOV asserts that 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. The Company reached a settlement in principle with the EPA to resolve the NOV. That settlement was contemplated in the plan filed and approved by the IURC on January 28, 2015 in the SIGECO Electric Environmental Compliance Filing.

Information Request
SIGECO and Alcoa Generating Corporation (AGC), a subsidiary of ALCOA, own a 300 MW Unit 4 at the Warrick Power Plant as tenants in common. AGC and SIGECO also share equally in the cost of operation and output of the unit. In January 2013, AGC received an information request from the EPA under Section 114 of the Clean Air Act for historical operational information on the Warrick Power Plant. In April 2013, ALCOA filed a timely response to the information request.

Ozone NAAQS
On November 26, 2014, the U.S. 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. The EPA has stated that it intends to finalize the rule by October 2015. Upon finalization, the EPA will then determine whether a particular region is in attainment with the new standard. While it is possible that counties in southwest Indiana could be declared in non-attainment with the new standard, and thus may 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.

Water
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. Costs for compliance with these final regulations should qualify as federally mandated regulatory requirements and be recoverable under Indiana Senate Bill 251 referenced above.

Under the Clean Water Act, the EPA sets technology-based guidelines for water discharges from new and existing facilities. The EPA is currently in the process of revising the existing steam electric effluent limitation guidelines that set the technology-based water discharge limits for the electric power industry. The EPA is focusing its rulemaking on wastewater generated primarily by pollution control equipment necessitated by the comprehensive air regulations. The EPA released proposed rules on April 19, 2013 however the rule is not yet finalized. At this time, it is not possible to estimate what potential costs may be required to meet these new water discharge limits, however costs for compliance with these regulations should qualify as federally mandated regulatory requirements and be recoverable under Senate Bill 251 referenced above.

Conclusions Regarding Air and Water Regulations
To comply with Indiana's implementation plan of the Clean Air Act, the Company obtained authority from the IURC to invest in clean coal technology. Using this authorization, the Company invested approximately $411 million starting in 2001 with the last equipment being placed into service on January 1, 2010. The pollution control equipment included SCR systems, fabric filters, and an SO2 scrubber at its generating facility that is jointly owned with AGC. SCR technology is the most effective method of reducing NOX emissions where high removal efficiencies are required and fabric filters control particulate matter emissions. The unamortized portion of the $411 million clean coal technology investment was included in rate base for purposes of determining SIGECO's electric base rates approved in the latest base rate order obtained April 27, 2011. SIGECO's coal-fired generating fleet is 100 percent scrubbed for SO2 and 90 percent controlled for NOX.

Utilization of the Company's NOX and SO2 allowances can be impacted as regulations are revised and implemented. Most of these allowances were granted to the Company at zero cost; therefore, any reduction in carrying value that could result from future changes in regulations would be immaterial.

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 mercury and air toxin standards effective in 2015 and to address an outstanding Notice of Violation (NOV) from the EPA. The total investment is estimated to be between $80 and $90 million, roughly half of which will be made to control mercury in both air and water emissions, and the remaining investment will be made to address the issues raised in the NOV proceeding on the increase in sulfur trioxide emissions.

Coal Ash Waste Disposal & Ash Ponds
In June 2010, the EPA issued proposed regulations affecting the management and disposal of coal combustion products, such as ash generated by the Company's coal-fired power plants. The proposed rules more stringently regulate these byproducts and would likely increase the cost of operating or expanding existing ash ponds and the development of new ash ponds. The alternatives include regulating coal combustion by-products that are not being beneficially reused as hazardous waste. The EPA did not offer a preferred alternative, but took public comment on multiple alternative regulations.

In December 2014 the U.S. EPA released its final coal ash rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). At this time the final rule has not been published in the Federal Register and as such is not yet effective. Under the final rule the Company will be required to commence an enhanced groundwater monitoring program to determine whether its existing ash ponds must be closed or retrofitted with liners. The final rule allows beneficial reuse of ash and the Company will continue to beneficially reuse a majority of its ash. Legislation is currently being considered by Congress that would provide for enforcement of the federal program by states in lieu of citizen suits.

The Company originally estimated capital expenditures to comply with the alternatives in the proposal could be as much as $30 million, and such expenditures could exceed $100 million if the most stringent of the alternatives was selected. As the less stringent Subtitle D program was selected by U.S. EPA in the final rule, the Company expects capital expenditures to comply in the lower end of this range. Annual compliance costs could increase only slightly or be impacted by as much as $5 million. Costs for compliance with these regulations should qualify as federally mandated regulatory requirements and be recoverable under Senate Bill 251 referenced above.

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 base load generation including effective energy conservation, demand side management, and generation efficiency measures;
- Inclusion of incentives for investment in advanced clean coal technology and support for research and development; 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; and
- Developing renewable energy and energy efficiency performance contracting projects through its wholly owned subsidiary, Energy Systems Group.
- Helping energy producers install pipes that allow for more natural gas power generation and reduce gas flaring through its Infrastructure Services segment.

In April 2007, the US Supreme Court determined that greenhouse gases (GHG's) meet the definition of "air pollutant" under the Clean Air Act and ordered the EPA to determine whether GHG emissions cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. The endangerment finding was finalized in December 2009, concluding that carbon emissions pose an endangerment to public health and the environment.

The EPA has finalized two sets of GHG regulations that apply to the Company's generating facilities. In 2009, the EPA finalized a mandatory GHG emissions registry which requires the reporting of emissions. The EPA has also finalized a revision to the Prevention of Significant Deterioration (PSD) and Title V permitting rules which would require facilities that emit 75,000 tons or more of GHG's a year to obtain a PSD permit for new construction or a significant modification of an existing facility. The EPA's PSD and Title V permitting rules for GHG's were upheld by the US Court of Appeals for the District of Columbia, and in June 2014 the US Supreme Court upheld the regulations with respect to applicability to major sources such as coal-fired power plants that are required to hold PSD construction and Title V air operating permits for other criteria pollutants.

While the Company has no plans to invest in new coal-fired generation, there is also a rule making and related legal challenge involving new source performance standards for new construction. This rulemaking must be finalized and withstand legal scrutiny in order for the EPA to implement its proposed new source performance standards for existing units discussed below.

In July 2013, the President announced a Climate Action Plan, which calls on the EPA to finalize the rule for new construction expeditiously and by June 2015 finalize, New Source Performance Standards (NSPS) for GHG's for existing electric generating units which would apply to the Company's power plants. States must have their implementation plans to the EPA no later than

June 2016. On June 2, 2014, the EPA proposed its rule for states to regulate CO2 emissions from existing electric generating units. The rule, when final, will require states to adopt plans that reduce CO2 emissions by 30 percent from 2005 levels by 2030. The EPA provided an extended time frame for public commentary to December 1, 2014. The proposal sets state-specific CO2 emission rate-based CO2 goals (measured in lb CO2/MWh) and guidelines for the development, submission and implementation of state plans to achieve the state goals. These state-specific goals are calculated based upon 2012 average emission rates aggregated for all fossil fuel-based units in the state. For Indiana, the proposal uses a 2012 emission rate of 1,923 lb CO2/MWh, and sets an interim goal of 1,607 lb CO2/MWh and a final emission goal of 1,531 lb CO2/MWh that must be met by 2030. Under this proposal, these CO2 emission rate goals do not apply directly to individual units, or generating systems. They instead are state goals. As such, the state must establish a framework that will guide how compliance will be met on a statewide basis. The state's interim or "phase in" goal of 1,607 lb CO2/MWh must be met as averaged over a ten-year period (2020 - 2029) with progress toward this goal to be demonstrated for every two rolling calendar years starting in 2020, with the first report due in 2022.

Under the proposal all states have unique goals based upon each state's mix of electric generating assets. The EPA is proposing a 20 percent reduction in Indiana's total CO2 emission rate compared to 2012. At 20 percent Indiana's CO2 emission rate reduction requirement is tied with West Virginia as the 9th lowest reduction requirement. This is due in part to the EPA's attempt to recognize the existing generating resource mix in the state and take into account each state's ability to cost effectively lower its CO2 emission rate through a portfolio approach including energy efficiency and renewables, improving power plant heat rates, and dispatching lower emitting fuel sources. Each state's goals were set by taking 2012 emissions data and applying four "building blocks" of emission rate improvements that the EPA asserts can be achieved by that state. These four building blocks constitute the EPA's determination of "Best System of Emission Reductions that has been adequately demonstrated," which defines the EPA's authority under § 111(d) for existing sources. When applied to each state, the portfolio approach leads to significant differences in requirements across state lines. With the exception of building block number 1 (heat rate improvement of 6 percent), other building blocks are tailored to individual states based upon each state's existing generating mix and what the EPA concluded a state could reasonably accomplish to reduce its CO2 emission rate. The Company timely filed comments to the Clean Power Plan proposal on December 1, 2014. The State of Indiana also filed public comments, asking that the proposal be withdrawn. Despite having just been recently proposed and not expected to be finalized until summer of 2015, legal challenges to the EPA's proposal have begun. On July 31, 2014, litigation was filed by the state of Indiana and other parties challenging the rules which may delay the timing of approval of the various state plans. That litigation has been set for argument before the U.S. Court of Appeals for the D.C. circuit in April of 2015, with a decision expected later in the summer.

With respect to the state of Indiana, the four building blocks that support Indiana's goal are as follows:
(1) Heat rate (HR) improvements of 6 percent (this is consistently applied to all states).
(2) Increasing the dispatch of existing natural gas baseload generation sources to 70 percent.
(3) Renewable energy portfolio requirements of 5 percent (interim) and 7 percent (final).
(4) Energy efficiency / DSM that results in reductions of 1.5 percent annually starting in 2020, ending at a sustained 11 percent by 2030.

Under the proposal, Indiana may choose to implement a program based upon an annual average emission rate target or convert that target rate to a comparable CO2 emission cap. 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. Since 2005, the Company's emissions of CO2 have declined 23 percent (on a tonnage basis). These reductions have come from the retirement of FB Culley Unit 1, expiration of municipal contracts, electric conservation and 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. 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 1967 lbs CO_2/MWh to 1922 lbs CO_2/MWh, for a reduction of 3 percent. The Company's CO_2 emission rate of 1922 lbs/MWh is basically the same as the State's average CO_2 emission rate of 1923 lb CO_2/MWh.

Impact of Legislative Actions & Other Initiatives is Unknown

If the regulations referenced above are finalized by the EPA, or if legislation requiring reductions in CO2 and other GHG's or legislation mandating a renewable energy portfolio standard is adopted, such regulation could substantially affect both the costs and operating characteristics of the Company's fossil fuel generating plants and natural gas distribution businesses. At this time and in the absence of final legislation or rulemaking, 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. As the EPA moves toward finalization of the NSPS for existing sources and the State of Indiana begins formulation of its state implementation plan, the Company will continue to remain engaged with the state to develop a plan for compliance and have more information to enable it to better assess potential compliance costs with a final regulation. Costs to purchase allowances that cap GHG emissions or expenditures made to control emissions or lower carbon emission rates should be considered a federally mandated cost of providing electricity, and as such, the Company believes such costs and expenditures should be recoverable from customers through Senate Bill 251 as referenced above or Senate Bill 29, which was used by the Company to recover its initial pollution control investments.

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 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 $14.3 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, 2014 and 2013, approximately $3.6 million and $5.7 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, through Enterprises, 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 are reflected in Other Businesses. Enterprises has other legacy businesses that have investments in energy-related opportunities and services, real estate, and a leveraged lease, among other investments. All of the above is collectively referred to as the Nonutility Group.

The Nonutility Group results were earnings of $18.0 million for the year ended December 31, 2014, losses of $4.5 million and earnings of $21.7 million for the years ended December 31, 2013 and December 31, 2012, respectively. 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, 2014, 2013, and 2012, follow:

	Year Ended December 31,		
(In millions, except per share amounts)	2014	2013	2012
NET INCOME EXCLUDING COAL MINING & PROLIANCE RESULTS*	$39.1	$33.0	$21.7
CONTRIBUTION TO VECTREN BASIC EPS, EXCLUDING COAL MINING & PROLIANCE RESULTS*	$0.47	$0.41	$0.26
NET INCOME (LOSS) ATTRIBUTED TO:			
Infrastructure Services	$43.1	$49.0	$40.5
Energy Services	(3.2)	1.0	5.7
Coal Mining*		(16.0)	(3.5)
ProLiance*	—		(17.6)
Other Businesses	(0.8)	(1.0)	(3.4)

*Excludes Coal Mining Results in 2014 and ProLiance Results in 2013 - Years of Disposition (See page 27 regarding use of Non-GAAP Measures)

Infrastructure Services

Infrastructure Services provides underground pipeline construction and repair services through wholly owned subsidiaries Miller Pipeline, LLC (Miller) and Minnesota Limited, LLC (Minnesota Limited). Inclusive of holding company costs, earnings from Infrastructure Services' operations for the year ended December 31, 2014 were $43.1 million compared to $49.0 million in 2013, and $40.5 million in 2012. Results were lower in 2014 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 fixed price contracts. Using blanket contracts, customers are not contractually committed to specific volumes or specific time frames for project completion. These contracts are typically awarded on an annual basis. Under fixed price 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, 2014, Infrastructure Services had an estimated backlog of blanket contracts of $500 million and a backlog of fixed price contracts of $125 million, for a total backlog of $625 million. The estimated backlog at December 31, 2013 was $460 million for blanket contracts and $75 million for fixed price contracts, for a total of $535 million. Total Infrastructure Services gross revenues in 2014 were $779 million, compared to gross revenues of $784 million in 2013 and $664 million in 2012.

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.

As evidenced by increased backlog numbers, construction activity generally is expected to remain strong as utilities, municipalities and pipeline operators replace their aging natural gas and oil pipelines and related infrastructure. Construction activity has been favorably impacted as pipeline operators construct new pipelines due to the continued strong demand for shale gas and oil infrastructure. The recent drop in oil prices is not expected to have a significant impact on Infrastructure Services' operations in 2015 due to the project mix and the continued projected strong demand. Further, oil production cuts have been predominately related to the drilling of new wells and as such, pipeline is still being built for producing wells. Typically changes in the markets in which Infrastructure Services operate will lag an economic change by 8-12 months due to the fact that many projects have already started or have committed start dates. While the drop in oil prices could have a greater impact in 2016 and beyond if prices do not rebound in 2015, the mix of activity is favorable and the long term trends are good.

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 ESG. Inclusive of holding company costs, Energy Services’ operations were a loss of $3.2 million in 2014, compared to earnings of $1.0 million in 2013 and $5.7 million in 2012.

Results in 2014 were lower due to a reduction in tax deductions associated with energy efficiency projects. The impact of these tax deductions on results, net of consulting fees, was $4.4 million in 2014, compared to $7.0 million in 2013, and $6.8 million in 2012. These tax deductions were retroactively extended for 2014. Results in 2014 also 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 from CES. 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 intended to fund the Vectren Foundation, Inc. for an extended period.

The Company's long-term view of the performance contracting and sustainable infrastructure opportunities remains positive as the national focus on energy conservation, renewable energy, and sustainability continues 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 a significant increase in the backlog and sales funnel.

As of December 31, 2014, backlog was $144 million, compared to $72 million at December 31, 2013 and $77 million at December 31, 2012.

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, an Indiana-based wholly owned subsidiary of Hallador Energy Company. Sunrise Coal owns and operates coal mines in the Illinois Basin and 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. 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. Results from Coal Mining for the year ended December 31, 2014, inclusive of the approximate $20 million loss on the sale, was a loss of $21.1 million, net of tax, compared to losses of $16.0 million and $3.5 million for the years ended December 31, 2013 and 2012, respectively.

ProLiance

The Company has an investment in 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 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 (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 compared to a loss of $17.6 million in 2012. At December 31, 2014, ProLiance had approximately $50.6 million of capitalization remaining on its balance sheet, comprised of $33.6 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 $35.4 million, one other midstream asset, $7.8 million in cash, and a small amount of other working capital. The Company's remaining investment in ProLiance at December 31, 2014 totals $30.6 million and is comprised of $20.5 million of equity and a $10.1 million note receivable.

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 a 25 percent interest, which it accounts for using the equity method. The project, which includes a pipeline system, is expected to include 17 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 connect the caverns to the pipeline system. 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.

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 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. The joint venture intends to vigorously defend itself and has asserted counterclaims substantially in excess of the amounts asserted by Williams. As such, as of December 31, 2014, ProLiance has no material reserve recorded related to this matter and this litigation has not materially impacted ProLiance's results of operations or statement of financial position.

Other Businesses

Within the Nonutility business segment, there are legacy investments involved in energy-related opportunities and services, real estate, a leveraged lease, and other ventures. As of December 31, 2014, remaining legacy investments included in the Other Businesses portfolio total $25.0 million, of which $23.4 million are included in Other nonutility investments and $1.6 million are included in Investments in unconsolidated affiliates. The investment is made up of the following: commercial real estate, $8.0 million; a leveraged lease, $15.2 million ($5.2 million net of related deferred taxes); and other investments, $1.8 million. Net of deferred taxes, the net investment associated with these legacy investments at December 31, 2014 was $19.0 million.

Other Businesses results were a loss of $0.8 million in 2014, compared to a loss of $1.0 million in 2013 and a loss of $3.4 million in 2012. Results in 2014 and 2013 reflect other minor operating results of the remaining legacy investments. Results in 2012 reflect after tax charges of $2.2 million related to the carrying value of an energy-related investment originally made in 1999.

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. For a public entity, the guidance is effective for annual reporting periods beginning after December 15, 2016, with early adoption not permitted. An entity should apply the amendments in this update retrospectively to each prior reporting period presented or retrospectively with the cumulative effect of initially applying this update recognized at the date of initial application. The Company is currently evaluating the standard to understand the overall impact it 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 about discontinued operations 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 did not early adopt this guidance in accounting for the sale of its Coal Mining assets. The Company is currently evaluating the impact of this guidance, if any.

Accounting for Stock Compensation
In June 2014, the FASB issued new accounting guidance on accounting for share-based payments when the terms of an award provide that a performance target could be achieved after the requisite service period. These amendments provide explicit guidance on whether to treat a performance target that could be achieved after the requisite service period as a performance condition that affects vesting or as a non-vesting condition that affects the grant-date fair value of an award. This guidance is effective for annual periods and interim periods within those periods beginning after December 15, 2015, with early adoption permitted. The Company's current practice for accounting for stock compensation follows the prescribed manner as suggested by the update. Adoption of this guidance will not have a

material impact on the Company’s financial statements.

Financial Reporting of Going Concern

In August 2014, the FASB issued new accounting guidance with respect to reporting on an entity's ability to continue as a going concern. This new guidance requires management to assess an entity's ability to continue as a going concern by incorporating and expanding upon certain principles that are currently in U.S. auditing standards, which requires disclosure surrounding what constitutes substantial doubt for the entity, including disclosure of management's plans to mitigate and alleviate substantial doubt. This guidance is effective for annual periods beginning after December 15, 2016, and for annual and interim periods thereafter, with early application permitted. Adoption of this guidance will not have a material impact on the Company's financial statements.

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 reclamation liabilities, and estimating uncollectible accounts, unbilled revenues, deferred income taxes, and coal reserves, 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). During the year, the Company determined that a certain Energy Services asset's carrying value exceeded its net realizable value and thus was written down to zero, resulting in an after tax charge of $0.7 million.

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 components 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.

Specific to Energy Services, the Company performed a detailed analysis related to the carrying value of goodwill and other intangible assets recorded upon Energy Systems Group's acquisition of the federal sector energy services unit of Chevron Energy Solutions from Chevron, USA (Federal Business Unit or FBU). A triggering event resulted from the failure to sign sufficient sales orders by the contractually determined earn-out date of December 31, 2014. The failure to achieve the earn-out resulted in the reversal of the contingent consideration liability and was considered a triggering event for goodwill and intangible asset testing at December 31, 2014. The Company performed a detailed discounted cash flow analysis of the Energy Services operating segment using various revenue scenarios to understand the effects of the event on its sales and earnings forecast. As of December 31, 2014, the analysis indicates that there is no impairment related to the goodwill or other intangible assets recorded upon the acquisition of the FBU. The estimates used in the forecast scenarios are highly subjective and may differ materially from actual results.

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. The Company used the following weighted average assumptions to develop 2014 periodic benefit cost: a discount rate of approximately 4.74 percent; an expected return on plan assets of 7.75 percent; a rate of compensation increase of 3.50 percent; and an inflation assumption of 2.75 percent. Due to higher interest rates, the discount rate is 70 basis points higher than the assumption used in 2013. The rate of return and inflation rates remained the same from 2013 to 2014. To estimate the 2014 obligation and 2015 costs, the Company used the following weighted average assumptions: a discount rate of approximately 4.05 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. Further, at December 31, 2014, management updated its base mortality assumption to the Society of Actuaries (SOA) 2014 table as well as updated its projected mortality improvement. 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 a pension and postretirement cost of approximately $9.3 million in 2015.

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, and short-term obligations outstanding at December 31, 2014 approximated $320 million and $0 million, respectively. 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, 2014 approximated $875 million and $156 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, 2014, was $382 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 and Indiana Gas, at December 31, 2014, 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. On January 30, 2014, Moody's upgraded the senior unsecured credit ratings of Utility Holdings and Indiana Gas from A3 to A2. In addition, Utility Holdings' commercial paper was upgraded to P-1 from P-2, and SIGECO's senior secured debt was upgraded to Aa3 from A1. 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 component was 50 percent and 46 percent of long-term capitalization at December 31, 2014 and 2013, respectively. Long-term capitalization includes long-term debt, including current maturities, as well as common shareholders’ equity. The increase in 2014 is primarily the result of repayment of Vectren Capital variable rate term loans from proceeds from the sale of Coal Mining, resulting in a higher equity weighted capital structure.

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, 2014, 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 the Company believes it will have the ability to continue to do so. Given the Company's intent to maintain a balanced long-term capitalization ratio, it 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, the resources required for capital investment remain uncertain for a variety of factors including pending legislative and regulatory initiatives involving gas pipeline infrastructure replacement; expanded EPA regulations for air, water, and fly ash; and growth of Infrastructure Services and Energy Services. These regulations may result in the need to raise additional capital in the coming years. In addition, the Company recently acquired an energy services business and may further expand its nonutility businesses through other acquisitions and/or joint venture investments. The timing and amount of such investments depends on a variety of factors, including the availability of acquisition targets and available liquidity.

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.

On August 29, 2014, the Company closed on a transaction to sell its wholly owned coal mining subsidiary, Vectren Fuels, to Sunrise Coal. The initial cash proceeds from the sale were used to retire $200 million in outstanding Vectren Capital bank term loans and pay down outstanding short-term debt.

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.

Consolidated Short-Term Borrowing Arrangements

At December 31, 2014, the Company has $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 $194 million was available for the Utility Group operations and approximately $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 until financed on a long-term basis.

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

	Utility Group Borrowings			Nonutility Group Borrowings		
(In millions)	2014	2013	2012	2014	2013	2012
As of Year End						
Balance Outstanding	$156.4	$28.6	$116.7	$—	$40.0	$162.1
Weighted Average Interest Rate	0.50 %	0.29 %	0.40 %	NA	1.27 %	1.35 %

Annual Average Balance Outstanding	$35.6	$119.6	$77.6	$34.5	$119.3	$151.5
Weighted Average Interest Rate	0.34%	0.34%	0.47%	1.29%	1.35%	1.44%
Maximum Month End Balance Outstanding	$156.4	$176.1	$214.2	$76.3	$173.8	$216.1

Throughout 2014, 2013, and 2012, Utility Holdings has placed commercial paper without any significant issues and did not borrow from its backup credit facility in any of these periods.

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 $6.1 million in 2014, $6.9 million in 2013, and $7.2 million in 2012.

Potential Uses of Liquidity

Pension & Postretirement Funding Obligations

As of December 31, 2014, assets related to the Company’s qualified pension plans were approximately 87 percent of the projected benefit obligation on a GAAP basis and 108 percent of the target liability for ERISA purposes. The Company currently anticipates making contributions of $20 million to qualified pension plans in 2015.

Corporate Guarantees

The Company issues parent level guarantees to certain vendors and customers of its wholly owned subsidiaries and unconsolidated affiliates. These guarantees do not represent incremental consolidated obligations; rather, they represent parental guarantees of subsidiary and unconsolidated affiliate obligations in order to allow those subsidiaries and affiliates the flexibility to conduct business without posting other forms of collateral. At December 31, 2014, parent level guarantees, excluding guarantees of obligations of the federal business unit acquired from Chevron USA on April 1, 2014, as further described below, support a maximum of $25 million of Energy System Group's (ESG) performance contracting commitments and warranty obligations and $35 million of other project guarantees.

On April 1, 2014, ESG acquired the federal sector energy services unit of CES from Chevron USA. Pursuant to the agreement, the acquisition includes a provision whereby Vectren Enterprises, Inc., the wholly owned holding company for the Company's nonutility investments, provided CES with an indemnification for potential claims against the seller that could arise related to the performance of work undertaken by ESG.

The acquisition also includes ESG guarantees of performance under certain assumed contracts. The guarantees include energy savings that are used to satisfy project financing. The Company guarantees ESG's performance under these energy savings guarantees. The total maximum amount of the energy savings guarantees is approximately $140 million and will only be called upon in the event energy savings established under the existing contracts executed by CES are not achieved. 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 Vectren Enterprises, Inc. provision providing indemnification to CES and the Company guarantee of the Keenan Ft. Detrick Energy operations agreement with Keenan as discussed above, do not state a maximum guarantee. Due to the nature of work performed under these contracts, the Company cannot estimate a maximum potential amount of future payments.

In addition, the Company has approximately $17 million of other guarantees outstanding supporting other consolidated subsidiary operations, of which $11 million represents letters of credit supporting other nonutility operations.

While there can be no assurance that neither the Vectren Enterprises, Inc.'s indemnification nor the Company guarantee provisions will be called upon, the Company believes that the likelihood of a material amount being triggered under any of these provisions is remote.

Performance Guarantees & Product Warranties

In the normal course of business, wholly owned subsidiaries, including ESG, issue performance bonds or other forms of assurance that commit them to timely install infrastructure, operate facilities, pay vendors or subcontractors, and/or support warranty obligations. Based on a history of meeting performance obligations and installed products operating effectively, no significant liability or cost has been recognized for the periods presented.

Specific to ESG, in its role as a general contractor in the performance contracting industry, at December 31, 2014, there are 50 open surety bonds supporting future performance. The average face amount of these obligations is $6.9 million, and the largest obligation has a face amount of $57.3 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, 2014, approximately 42 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. The Company has no accruals for these warranty and energy obligations as of December 31, 2014.

Planned Capital Expenditures & Investments

During 2014 capital expenditures and other investments approximated $448 million, of which approximately $351 million related to Utility Group expenditures. This compares to 2013 where consolidated investments were approximately $411 million with $268 million attributed to the Utility Group and 2012 where consolidated investments were approximately $370 million with $250 million attributed to the Utility Group. Planned Utility Group capital expenditures, including contractual purchase commitments, for the five-year period 2015 - 2019 are expected to total approximately (in millions): $405, $395, $360, $355, and $380, 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 for recurring infrastructure investments, including contractual purchase commitments, for the five-year period 2015 - 2019 are expected to total (in millions): $50, $80, $80, $50, and $50, respectively.

Contractual Obligations

The following is a summary of contractual obligations at December 31, 2014:

(In millions)	Total	2015	2016	2017	2018	2019	Thereafter
Long-term debt (1)	$1,577.3	$170.0	$73.0	$75.0	$100.0	$60.0	$1,099.3
Short-term debt	156.4	156.4	—	—	—	—	—
Long-term debt interest commitments	900.6	79.3	66.6	65.2	60.3	53.5	575.7
Plant and nonutility plant purchase commitments	4.0	3.6	0.2	0.2	—	—	—
Operating leases	24.2	8.2	5.6	3.2	2.0	1.6	3.6
Total (2)	$2,662.5	$417.5	$145.4	$143.6	$162.3	$115.1	$1,678.6

(1) The debt due in 2015 is comprised of debt issued by Indiana Gas, Utility Holdings and Vectren Capital.

(2) The Company has other long-term liabilities that total approximately $234 million. This amount is comprised of the following: pension obligations $65 million; postretirement obligations $49 million; deferred compensation and share-based compensation obligations $51 million; asset retirement obligations $55 million; investment tax credits $5 million; environmental remediation obligations $4 million; and other obligations including unrecognized tax benefits totaling $5 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. 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 $488.2 million in 2014, compared to $587.0 million in 2013 and $387.4 million in 2012.

The $98.8 million decrease in operating cash flow in 2014 compared to 2013 is driven by changes in certain working capital accounts, specifically 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.

In 2013, operating cash flows increased $199.6 million compared to 2012. This increase was primarily due to a greater level of cash from working capital in 2013 as compared to 2012 mostly due to higher inventories at SIGECO and an increase in accounts receivable in 2012. The change in noncurrent assets was primarily driven by the deferral for future recovery of certain coal costs pursuant to a regulatory order in the prior year. In addition, contributions to benefit plans were $6.8 million lower during 2013 compared to 2012.

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 2012, 2013, and 2014. A significant portion of the Company’s capital expenditures qualified for this bonus treatment.

Financing Cash Flow

Net cash flow required for financing activities was $257.6 million, $179.9 million, and $19.6 million for the years ended December 31, 2014, 2013, and 2012, respectively. Financing activity across all periods reflects the Company’s utilization of the long-term capital markets in the current low interest rate environment. In addition, a decrease in net borrowings in 2014 is due principally to the use of proceeds from the sale of Vectren Fuels. Since 2012, the Company has issued $749 million in long-term debt, of which $587 million was used to refinance maturing or called long-term debt and $162 million was used to meet its incremental debt financing requirements. These lower rates have favorably impacted interest expense throughout the periods presented. The Company’s operating cash flow funded over 85 percent of capital expenditures and dividends in 2014, 100 percent in 2013, and over 80 percent in 2012. Recently completed long-term financing transactions are more fully described below.

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.

52

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 $100.0 million in August 2013 and repaid the loan in August of 2014 with a portion of the proceeds received from the sale of Vectren Fuels.

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.

Vectren Capital 2012 Term Loan
On November 1, 2012, 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 November 2012 and repaid the loan in August 2014 with a portion of the proceeds received from the sale of Vectren Fuels.

Utility Holdings 2012 Debt Transactions

On February 1, 2012, Utility Holdings issued $100 million of senior unsecured notes at an interest rate of 5.00 percent per annum and with a maturity date of February 3, 2042. The notes were sold to various institutional investors pursuant to a private placement note purchase agreement executed in November 2011 with a delayed draw feature. These senior notes are unsecured and jointly and severally guaranteed by Utility Holdings' regulated utility subsidiaries, SIGECO, Indiana Gas, and VEDO. The proceeds from the sale of the notes, net of issuance costs, totaled approximately $99.5 million. These notes have no sinking fund requirements and interest payments are due semi-annually. These notes contain customary representations, warranties and covenants, including a leverage covenant consistent with leverage covenants contained in other Utility Holdings' borrowing arrangements.

Mandatory Tenders

At December 31, 2014, certain series of SIGECO bonds, aggregating $49.1 million, currently bear interest at fixed rates and are subject to mandatory tender in September 2017. 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 $165.7 million in 2014, $405.1 million in 2013, and $356.9 million in 2012. The decrease in cash flow required for investing activities in 2014 as compared to 2013 is due to proceeds received from the sale of Vectren Fuels. Cash proceeds totaled $311 million, which is inclusive of a $15 million change in working capital from December 31, 2013, through closing. Further, capital expenditures increased in 2014 as compared to 2013 by $54.9 million. The increase in Utility Group capital expenditures is attributable to greater expenditures for gas infrastructure improvement projects and environmental compliance. Investing activity for the year ended December 31, 2014 also reflects the acquisition of the federal business unit from Chevron Energy Solutions. Capital expenditures for nonutility equipment increased approximately $13 million in 2013 compared to 2012, primarily due to growth in 2013 in the Infrastructure Services segment.

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.
- Catastrophic events such as fires, earthquakes, explosions, floods, ice storms, tornadoes, terrorist acts, cyber attacks, or other similar occurrences could adversely affect Vectren'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, 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

54

demand for natural gas, electricity, and other nonutility products and services; impacts 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 real estate and other legacy 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, LLC. 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; the ability to attract and retain qualified employees; cancellation and/or reductions in the scope of projects by customers; 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.
- Changes in or additions to federal, state or local legislative requirements, such as changes in or additions to tax laws or rates, pipeline safety regulations, environmental laws, including laws governing greenhouse gases, mandates of sources of renewable energy, and other regulations.

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 when managing interest rate risk.

The Company has in place 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 volatile gas costs may have on the Company's financial condition. Although the Company's regulated operations are exposed to limited commodity price risk, volatile 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 purchases for each Company via the use of physical 5 year and 10 year fixed-price purchases and financial products, including call options. Such contracts are generally short term in nature and are insignificant in terms of value and volume at December 31, 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, 2014 and 2013.

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 its gasoline 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. The Company limits this risk by allowing only an annual average of 15 percent to 25 percent of its total debt to be exposed to variable rate volatility. This targeted range may not always be attained during the seasonal increases in short-term borrowings. As of December 31, 2014 debt subject to interest rate volatility was 11 percent 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 2014 and 2013, the weighted average combined borrowings under these arrangements approximated $245 million and $421 million, respectively. At December 31, 2014, combined borrowings under these arrangements were $198 million. As of December 31, 2013 combined borrowings under these arrangements were $309 million. Based upon average borrowing rates under these facilities during the years ended December 31, 2014 and 2013, an increase of 100 basis points (one percentage point) in the rates would have increased interest expense by approximately $2.4 million in 2014 and $4.2 million in 2013.

Other Risks

By using financial instruments 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, 2014. Management certified this in its Sarbanes Oxley Section 302 certifications, which are filed as exhibits to this 2014 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, 2014 and 2013, 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, 2014. 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, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, 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, 2014, 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 17, 2015 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP
Indianapolis, Indiana
February 17, 2015

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, 2014, 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, 2014, 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, 2014 of the Company and our report dated February 17, 2015 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ DELOITTE & TOUCHE LLP
Indianapolis, Indiana
February 17, 2015

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

	At December 31,	
	2014	2013
ASSETS		
Current Assets		
Cash & cash equivalents	$86.4	$21.5
Accounts receivable - less reserves of $6.0 & $6.8, respectively	196.0	259.2
Accrued unbilled revenues	164.8	134.2
Inventories	118.5	134.4
Recoverable fuel & natural gas costs	9.8	5.5
Prepayments & other current assets	110.9	75.6
Total current assets	686.4	630.4
Utility Plant		
Original cost	5,718.7	5,389.6
Less: accumulated depreciation & amortization	2,279.7	2,165.3
Net utility plant	3,439.0	3,224.3
Investments in unconsolidated affiliates	23.4	24.0
Other utility & corporate investments	37.2	38.1
Other nonutility investments	33.6	33.8
Nonutility plant - net	378.0	657.2
Goodwill	289.9	262.3
Regulatory assets	233.6	193.4
Other assets	41.2	39.1
TOTAL ASSETS	$5,162.3	$5,102.6

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, 2014	2013
LIABILITIES & SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$248.9	$227.2
Refundable fuel & natural gas costs	2.5	2.6
Accrued liabilities	184.9	182.1
Short-term borrowings	156.4	68.6
Current maturities of long-term debt	170.0	30.0
Total current liabilities	762.7	510.5
Long-term Debt - Net of Current Maturities	1,407.3	1,777.1
Deferred Income Taxes & Other Liabilities		
Deferred income taxes	741.2	707.4
Regulatory liabilities	410.3	387.3
Deferred credits & other liabilities	234.2	166.0
Total deferred credits & other liabilities	1,385.7	1,260.7
Commitments & Contingencies (Notes 7, 17-20)		
Common Shareholders' Equity		
Common stock (no par value) – issued & outstanding 82.6 & 82.4 shares, respectively	715.7	709.3
Retained earnings	892.2	845.7
Accumulated other comprehensive (loss)	(1.3)	(0.7)
Total common shareholders' equity	1,606.6	1,554.3
TOTAL LIABILITIES & SHAREHOLDERS' EQUITY	$5,162.3	$5,102.6

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,		
	2014	2013	2012
OPERATING REVENUES			
Gas utility	$944.6	$810.0	$738.1
Electric utility	624.8	619.3	594.9
Nonutility	1,042.3	1,061.9	899.8
Total operating revenues	2,611.7	2,491.2	2,232.8
OPERATING EXPENSES			
Cost of gas sold	468.7	358.1	301.3
Cost of fuel & purchased power	201.8	202.9	192.0
Cost of nonutility revenues	346.4	366.7	295.1
Other operating	943.4	891.6	781.0
Depreciation & amortization	273.4	277.8	254.6
Taxes other than income taxes	63.5	60.5	56.3
Total operating expenses	2,297.2	2,157.6	1,880.3
OPERATING INCOME	314.5	333.6	352.5
OTHER INCOME (EXPENSE)			
Equity in earnings (losses) of unconsolidated affiliates	0.5	(59.7)	(23.3)
Other income – net	19.7	17.7	8.3
Total other income (expense)	20.2	(42.0)	(15.0)
Interest expense	86.7	87.9	96.0
INCOME BEFORE INCOME TAXES	248.0	203.7	241.5
Income taxes	81.1	67.1	82.5
NET INCOME	$166.9	$136.6	$159.0
AVERAGE COMMON SHARES OUTSTANDING	82.5	82.3	82.0
DILUTED COMMON SHARES OUTSTANDING	82.5	82.4	82.1
EARNINGS PER SHARE OF COMMON STOCK:			
BASIC	$2.02	$1.66	$1.94
DILUTED	$2.02	$1.66	$1.94

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,		
	2014	2013	2012
NET INCOME	$166.9	$136.6	$159.0
Accumulated other comprehensive income (AOCI) of unconsolidated affiliates			
Net amount arising during the year before tax	—	4.6	11.3
Income taxes	—	(1.8)	(4.6)
AOCI of unconsolidated affiliates, net of tax	—	2.8	6.7
Pension & other benefits			
Amounts arising during the year before tax	(52.6)	61.4	(3.3)
Reclassifications to periodic cost before tax	3.4	9.1	7.1
Deferrals to regulatory assets	48.2	(69.1)	0.2
Income taxes	0.4	(0.6)	(1.6)
Pension & other benefits costs, net of tax	(0.6)	0.8	2.4
Cash flow hedges			
Reclassifications to net income before tax	—	—	(0.1)
Cash flow hedges, net of tax	—	—	(0.1)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX	(0.6)	3.6	9.0
TOTAL COMPREHENSIVE INCOME	$166.3	$140.2	$168.0

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,		
	2014	2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$166.9	$136.6	$159.0
Adjustments to reconcile net income to cash from operating activities:			
Depreciation & amortization	273.4	277.8	254.6
Deferred income taxes & investment tax credits	37.9	43.3	84.3
Equity in (earnings) losses of unconsolidated affiliates	(0.5)	59.7	23.3
Provision for uncollectible accounts	7.3	6.8	8.2
Expense portion of pension & postretirement benefit cost	6.6	9.9	8.7
Other non-cash charges - net	5.8	5.8	9.8
Loss on sale of business	41.8	—	—
Gain on revaluation of contingent consideration	(14.8)	—	—
Changes in working capital accounts:			
Accounts receivable & accrued unbilled revenues	11.8	1.5	(67.1)
Inventories	(22.5)	24.2	3.3
Recoverable/refundable fuel & natural gas costs	(4.4)	22.4	(12.9)
Prepayments & other current assets	(35.2)	12.8	(5.1)
Accounts payable, including to affiliated companies	20.2	6.8	(14.8)
Accrued liabilities	12.3	(1.2)	3.4
Unconsolidated affiliate dividends	—	1.1	0.1
Employer contributions to pension & postretirement plans	(5.1)	(13.7)	(20.5)
Changes in noncurrent assets	0.1	(2.1)	(35.3)
Changes in noncurrent liabilities	(13.4)	(4.7)	(11.6)
Net cash provided by operating activities	488.2	587.0	387.4
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from:			
Long-term debt, net of issuance costs	62.4	481.7	199.5
Dividend reinvestment plan & other common stock issuances	6.1	6.9	7.2
Requirements for:			
Dividends on common stock	(120.4)	(117.3)	(115.3)
Retirement of long-term debt	(293.6)	(338.9)	(62.7)
Other financing activities	0.1	(2.1)	—
Net change in short-term borrowings	87.8	(210.2)	(48.3)
Net cash used in financing activities	(257.6)	(179.9)	(19.6)
CASH FLOWS FROM INVESTING ACTIVITIES			
Proceeds from:			
Sale of business	311.2	—	—
Unconsolidated affiliate distributions	1.1	—	0.2
Other collections	8.4	5.6	9.9
Requirements for:			
Transaction costs for sale of business	(9.5)	—	—
Capital expenditures, excluding AFUDC equity	(448.3)	(393.4)	(365.8)
Business acquisition	(28.6)	—	—
Other investments	—	(17.3)	(1.2)
Net cash used in investing activities	(165.7)	(405.1)	(356.9)

Net change in cash & cash equivalents	64.9	2.0	10.9
Cash & cash equivalents at beginning of period	21.5	19.5	8.6
Cash & cash equivalents at end of period	$86.4	$21.5	$19.5

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, 2012	81.9	$692.6	$786.2	$(13.3)	$1,465.5
Net income			159.0		159.0
Other comprehensive income				9.0	9.0
Common stock:					
Issuance: option exercises & dividend reinvestment plan	0.3	7.2			7.2
Dividends ($1.405 per share)			(115.3)		(115.3)
Other		0.7			0.7
Balance at December 31, 2012	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 (loss)				(0.6)	(0.6)
Common stock:					
Issuance: option exercises & dividend reinvestment plan	0.2	6.1			6.1
Dividends ($1.460 per share)			(120.4)		(120.4)
Other		0.3			0.3
Balance at December 31, 2014	82.6	$715.7	$892.2	$(1.3)	$1,606.6

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), Southern Indiana Gas and Electric Company (SIGECO), 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 (Energy Act). Vectren was incorporated under the laws of Indiana on June 10, 1999.

Indiana Gas provides energy delivery services to approximately 575,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 143,000 electric customers and over 110,000 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 313,000 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 through the sale of Vectren Fuels. 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 are reflected in Other Businesses. Enterprises has other legacy businesses that have investments in energy-related opportunities and services, real estate, and a leveraged lease, 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.

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, reclamation liabilities, 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. Nonutility inventory is valued at the lower of cost or market.

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. During the year, the Company determined that a certain Energy Services asset's carrying value exceeded its net realizable value and thus was written down to zero, resulting in an after tax charge of $0.7 million.

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 (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 that test 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.

Specific to Energy Services, the Company performed a detailed analysis related to the carrying value of goodwill and other intangible assets recorded upon Energy Systems Group's acquisition of the federal sector energy services unit of Chevron Energy Solutions from Chevron, USA (Federal Business Unit or FBU). A triggering event resulted from the failure to sign sufficient sales orders by the contractually determined earn-out date of December 31, 2014. The failure to achieve the earn-out resulted in the reversal of the contingent consideration liability and was considered a triggering event for goodwill and intangible asset testing at December 31, 2014. The Company performed a detailed discounted cash flow analysis of the Energy Services operating segment using various revenue scenarios to understand the effects of the event on its sales and earnings forecast. As of December 31, 2014, the analysis indicates that there is no impairment related to the goodwill or other intangible assets recorded upon the acquisition of the FBU. The estimates used in the forecast scenarios are highly subjective and may differ materially from actual results.

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 probable future revenues associated with certain incurred costs, which will be recovered 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 at December 31, 2014 or 2013, 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 exempted 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. The goods and services delivered by the Company subject to unbilled revenue accruals include gas, electricity, energy services, and infrastructure services.

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 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 $32.3 million in 2014, $29.6 million in 2013, and $26.9 million in 2012. 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, four operating segments in its Nonutility Group, and a Corporate and Other segment.

Fair Value Measurements
Certain assets and liabilities are valued and/or 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:

(In millions)	At December 31, 2014			2013		
	Original Cost	Depreciation Rates as a Percent of Original Cost		Original Cost	Depreciation Rates as a Percent of Original Cost	
Gas utility plant	$3,011.0	3.4	%	$2,762.2	3.5	%
Electric utility plant	2,602.5	3.3	%	2,519.8	3.3	%
Common utility plant	54.3	3.2	%	53.4	3.0	%
Construction work in progress	50.9	—		54.2	—	
Total original cost	$5,718.7			$5,389.6		

SIGECO and Alcoa Generating Corporation (AGC), a subsidiary of ALCOA, own the 300 MW Unit 4 at the Warrick Power Plant as tenants in common. SIGECO's share of the cost of this unit at December 31, 2014, is $188.0 million with accumulated depreciation totaling $93.5 million. AGC and SIGECO also 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.

Nonutility plant, net of accumulated depreciation and amortization follows:

(In millions)	At December 31, 2014	2013
Coal mine development costs & equipment	$—	$242.0
Computer hardware & software	106.1	102.7
Land & buildings	72.1	129.3
Vehicles & equipment	182.7	165.2
All other	17.1	18.0
Nonutility plant - net	$378.0	$657.2

Nonutility plant is presented net of accumulated depreciation and amortization totaling $361.9 million and $541.7 million as of December 31, 2014 and 2013, respectively. For the years ended December 31, 2014, 2013, and 2012, the Company capitalized interest totaling $0.6 million, $0.5 million, and $1.8 million, respectively, on nonutility plant construction projects.

4. Regulatory Assets & Liabilities

Regulatory Assets
Regulatory assets consist of the following:

	At December 31,	
(In millions)	2014	2013
Future amounts recoverable from ratepayers related to:		
Benefit obligations (See Note 11)	$105.3	$57.1
Net deferred income taxes (See Note 10)	(14.8)	(5.8)
Asset retirement obligations & other	—	2.4
	90.5	53.7
Amounts deferred for future recovery related to:		
Deferred coal costs (See Note 19)	—	42.4
Cost recovery riders & other	33.3	18.6
	33.3	61.0
Amounts currently recovered in customer rates related to:		
Unamortized debt issue costs & hedging proceeds	33.5	34.6
Demand side management programs	0.6	2.5
Indiana authorized trackers	25.6	30.8
Deferred coal costs (See Note 19)	35.3	—
Ohio authorized trackers	12.7	7.9
Premiums paid to reacquire debt	1.7	2.2
Other base rate recoveries	0.4	0.7
	109.8	78.7
Total regulatory assets	$233.6	$193.4

Of the $109.8 million currently being recovered in customer rates, $0.6 million that is associated with demand side management programs is earning a return. The weighted average recovery period of regulatory assets currently being recovered in base rates, which totals $36 million, is 23 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 increase in 2014 of approximately $48 million is primarily a result of a decrease in discount rate and updated mortality assumptions used to value the projected benefit obligation. The Company records a Regulatory asset for that portion related to its rate regulated utilities. If the cost is ultimately recognized as a periodic cost, it will be recovered through rates charged to customers. See Note 11.

Regulatory Liabilities
At December 31, 2014 and 2013, the Company has approximately $410.3 million and $387.3 million, respectively, in Regulatory liabilities. Of these amounts, $373.5 million and $373.0 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 US Department of Energy and US 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.

See further discussion of Company issued guarantees and a Vectren Enterprises' indemnification associated with this acquisition in Note 17.

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 is expected to be signed in 2015. The failure to sign that targeted contract by the earn-out threshold date is viewed as timing only and not reflective of future sales opportunities. As a result, goodwill is not impaired at December 31, 2014.

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 losses of $16.0 million and $3.5 million for the years ended December 31, 2013 and 2012, respectively. The assets were classified as held for sale, as the sale of Vectren Fuels did not meet the requirements under GAAP to qualify as discontinued operations since Vectren will have 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), 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, 2014, shown at its 61 percent ownership share, is as follows and reflects that it relates primarily to ProLiance's investment in LA Storage, LLC (LA Storage) discussed below.

(In millions)	As of December 31, 2014
Cash	$4.8
Investment in LA Storage	21.6
Other midstream asset investment	4.2
Total investment in ProLiance	$30.6
Included in:	
Investments in unconsolidated affiliates	20.5
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 a 25 percent interest, which it accounts for using the equity method. The project, which includes a pipeline system, is expected to include 17 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 connect the caverns to the pipeline system. 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. At December 31, 2014, ProLiance's investment in the joint venture was $35.4 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 alleges 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. The joint venture intends to vigorously defend itself and has asserted counterclaims substantially in excess of the amounts asserted by Williams. As such, as of December 31, 2014, ProLiance has no material reserve recorded related to this matter and this litigation has not materially impacted ProLiance's results of operations or statement of financial position.

Transactions with ProLiance
Purchases from ProLiance for resale and for injections into storage for the years ended December 31, 2013, and 2012, totaled $200.5 million, and $274.5 million, respectively. The Company did not have any purchases from ProLiance for the year ended December 31, 2014. The Company purchases in 2013 and 2012 from ProLiance all occurred prior to June 18, 2013 when ProLiance exited the natural gas marketing business.

8. Nonutility Real Estate & Other Legacy Holdings

Within the nonutility group, there are legacy investments involved in real estate, a leveraged lease, and other ventures. As of December 31, 2014 and 2013, total remaining legacy investments included in the Other Businesses portfolio total $25.0 million and $26.5 million, respectively. Further separation of that 2014 investment by type of investment follows:

	December 31, 2014		
		Value Included In	
(In millions)	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	1.8	0.2	1.6
	$25.0	$23.4	$1.6

Commercial Real Estate
The Company holds a real estate investment in an office building. The Company's exposure to loss is limited to its investment.

Leveraged Lease
At December 31, 2014, the Company has an investment in a leveraged lease. The original cost for the leased facility was $27.5 million and was partially financed by non-recourse debt provided by lenders who were granted an assignment of rentals due and a security interest in the leased property, which they accepted as their sole remedy in the event of default by the lessee. Such remaining debt was approximately $16.3 million at December 31, 2014. The book value of this leverage lease is $5.2 million at December 31, 2014, net of related deferred taxes of $10.0 million.

9. Intangible Assets

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

(In millions)	At December 31,			
	2014		2013	
	Amortizing	Non-amortizing	Amortizing	Non-amortizing
Customer-related assets	$22.5	$ —	$17.4	$ —
Market-related assets	1.1	13.0	1.9	7.0
Intangible assets, net	$23.6	$ 13.0	$19.3	$ 7.0

As of December 31, 2014, 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 $10.0 million for customer-related assets and $3.4 million for market-related assets at December 31, 2014 and $8.1 million for customer-related assets and $2.6 million for market-related assets at December 31, 2013. Annual amortization associated with intangible assets totaled $2.8 million in 2014, $2.3 million in 2013 and $2.6 million in 2012. Amortization should approximate (in millions) $3.0, $2.3, $2.1, $2.1, and $2.1 in 2015, 2016, 2017, 2018, and 2019, respectively. Intangible assets are primarily in the Nonutility Group.

78

10. Income Taxes

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

	Year Ended December 31,		
	2014	2013	2012
Statutory rate:	35.0 %	35.0 %	35.0 %
State & local taxes-net of federal benefit	4.1	4.6	4.0
Amortization of investment tax credit	(0.3)	(0.3)	(0.3)
Depletion	(2.6)	(1.5)	(1.5)
Domestic production deduction	(1.1)	—	—
Energy efficiency building deductions	(1.6)	(3.8)	(3.0)
Other tax credits	(0.2)	(1.1)	(0.1)
Adjustment of income tax accruals and all other-net	(0.6)	0.1	0.1
Effective tax rate	32.7 %	33.0 %	34.2 %

Significant components of the net deferred tax liability follow:

	At December 31,	
(In millions)	2014	2013
Noncurrent deferred tax liabilities (assets):		
Depreciation & cost recovery timing differences	$757.9	$725.2
Leveraged lease	9.8	10.4
Regulatory assets recoverable through future rates	29.2	22.8
Alternative minimum tax carryforward	(13.3)	(23.5)
Employee benefit obligations	(14.5)	(6.7)
Net operating loss & other carryforwards	(2.0)	(1.2)
Regulatory liabilities to be settled through future rates	(27.5)	(18.7)
Impairments	(5.6)	(6.2)
Other – net	7.2	5.3
Net noncurrent deferred tax liability	741.2	707.4
Current deferred tax liabilities (assets):		
Deferred fuel costs-net	22.0	22.9
Alternative minimum tax carryforward	(38.1)	(33.7)
Net operating loss & other carryforwards	—	(4.9)
Other – net	(0.2)	1.8
Net current deferred tax liability (asset)	(16.3)	(13.9)
Net deferred tax liability	$724.9	$693.5

At December 31, 2014 and 2013, investment tax credits totaling $4.7 million and $5.3 million respectively, are included in Deferred credits & other liabilities. At December 31, 2014, the Company has alternative minimum tax carryforwards which do not expire. In addition, the Company has $2.0 million in net operating loss and general business credit carryforwards, which will expire in 5 to 20 years. The net operating loss carryforward was reduced for the impacts of unrecognized tax benefits and a valuation allowance relating to state net operating loss carryforwards. At December 31, 2014 and 2013, the valuation allowance was $7.3 million and $3.6 million, respectively.

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

	Year Ended December 31,		
(In millions)	2014	2013	2012
Current:			
Federal	$24.7	$12.4	$(8.2)
State	18.5	11.4	6.4
Total current taxes	43.2	23.8	(1.8)
Deferred:			
Federal	42.7	43.4	80.3
State	(4.2)	0.5	4.6
Total deferred taxes	38.5	43.9	84.9
Amortization of investment tax credits	(0.6)	(0.6)	(0.6)
Total income tax expense	$81.1	$67.1	$82.5

Uncertain Tax Positions

Following is a roll forward of unrecognized tax benefits for the three years ended December 31, 2014:

(In millions)	2014	2013	2012
Unrecognized tax benefits at January 1	$5.9	$4.8	$12.4
Gross increases - tax positions in prior periods	0.2	—	0.2
Gross decreases - tax positions in prior periods	(4.8)	(0.2)	(9.4)
Gross increases - current period tax positions	—	1.2	1.9
Settlements	—	—	(0.3)
Lapse of statute of limitations	(0.2)	0.1	—
Unrecognized tax benefits at December 31	$1.1	$5.9	$4.8

Of the change in unrecognized tax benefits during 2014, 2013, and 2012, almost none impacted the effective rate. The amount of unrecognized tax benefits, which if recognized, that would impact the effective tax rate was $0.8 million at December 31, 2014, and $0.7 million at each of December 31, 2013 and 2012.

The Company recognized income related to a reversal of interest expense previously accrued and net of penalties totaling approximately $0.1 million in 2014, $0.1 million in 2013, and $0.7 million in 2012. The Company had approximately $0.4 million and $0.5 million for the payment of interest and penalties accrued as of December 31, 2014 and 2013, respectively.

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 $1.1 million and $3.8 million, respectively, at December 31, 2014 and 2013.

The Company believes that a minor decrease in unrecognized tax benefits may be realized by the end of 2015 as a result of a lapse of the statute of limitations.

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, 2008. The IRS is currently examining the 2009-2012 federal income tax returns as part of a routine review by the Joint Committee of Taxation. 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, 2008. The statutes of limitations for assessment of federal income tax and Indiana income tax have expired with respect to tax years through 2008.

80

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 will be 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 2015. The Company continues to evaluate the impact adoption of the regulations and industry guidance will have on its consolidated financial statements. As of this date, the Company does not expect the adoption of the regulations 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, 2014, the Company maintains three 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, 2014 follows:

	Pension Benefits			Other Benefits		
(In millions)	2014	2013	2012	2014	2013	2012
Service cost	$7.4	$8.6	$7.7	$0.4	$0.5	$0.5
Interest cost	15.5	14.7	15.5	2.3	2.0	2.8
Expected return on plan assets	(22.7)	(22.1)	(21.2)	—	—	—
Amortization of prior service cost (benefit)	1.0	1.5	1.6	(3.0)	(3.2)	(2.5)
Amortization of actuarial loss	5.0	10.1	6.8	0.4	0.7	0.7
Amortization of transitional obligation	—	—	—	—	—	0.5
Settlement charge	3.1	1.3	—	—	—	—
Net periodic benefit cost	$9.3	$14.1	$10.4	$0.1	$—	$2.0

A portion of the net periodic benefit cost disclosed in the table above is capitalized as Utility plant. Costs capitalized in 2014, 2013, and 2012 are estimated at $2.8 million, $4.2 million, and $3.7 million, respectively.

The Company increased the discount rate used to measure periodic cost from 4.03 percent in 2013 to 4.74 percent in 2014 due to higher benchmark interest rates that approximated the expected duration of the Company's benefit obligations as of that valuation date. For fiscal year 2015, the weighted average discount rate assumption will decrease to 4.05 percent for the defined benefit pension plans, based on decreased benchmark interest rates.

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

	Pension Benefits			Other Benefits		
	2014	2013	2012	2014	2013	2012
Discount rate	4.74 %	4.03 %	4.82 %	4.66 %	3.91 %	4.75 %
Rate of compensation increase	3.50 %	3.50 %	3.50 %	N/A	N/A	N/A
Expected return on plan assets	7.75 %	7.75 %	7.75 %	N/A	N/A	N/A
Expected increase in Consumer Price Index	N/A	N/A	N/A	2.75 %	2.75 %	2.75 %

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, 2014 and 2013 follows:

	Pension Benefits		Other Benefits	
(In millions)	2014	2013	2014	2013
Benefit obligation, beginning of period	$338.4	$377.3	$51.3	$54.4
Service cost – benefits earned during the period	7.4	8.6	0.4	0.5
Interest cost on projected benefit obligation	15.5	14.7	2.3	2.0
Plan participants' contributions	—	—	0.9	0.8
Plan amendments	—	—	—	(0.2)
Actuarial loss (gain)	48.5	(32.7)	3.2	(2.4)
Settlement loss	1.7	1.5	—	—
Medicare subsidy receipts	—	—	—	—
Benefit payments	(25.3)	(22.8)	(4.8)	(3.8)
Settlement payments	(14.3)	(8.2)	—	—
Benefit obligation, end of period	$371.9	$338.4	$53.3	$51.3

The accumulated benefit obligation for all defined benefit pension plans was $356.4 million and $321.9 million at December 31, 2014 and 2013, respectively.

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. These changes are reflected in the Company's benefit obligation as of December 31, 2014.

Other Material Assumptions

The benefit obligation as of December 31, 2014 and 2013 was calculated using the following weighted average assumptions:

	Pension Benefits		Other Benefits	
	2014	2013	2014	2013
Discount rate	4.05 %	4.74 %	3.95 %	4.66 %
Rate of compensation increase	3.50 %	3.50 %	N/A	N/A
Expected increase in Consumer Price Index	N/A	N/A	2.50 %	2.75 %

To calculate the 2014 ending postretirement benefit obligation, medical claims costs in 2015 were assumed to be 6.5 percent higher than those incurred in 2014. That trend was assumed to reach its ultimate trending increase of 5 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 $0.3 million. The increase in the pension benefit obligation in 2014 is primarily due to a decrease in the discount rate used to measure the obligation at year end and, to a lesser extent, the updated mortality assumption.

Plan Assets

A reconciliation of the Company’s plan assets at December 31, 2014 and 2013 follows:

	Pension Benefits		Other Benefits	
(In millions)	2014	2013	2014	2013
Plan assets at fair value, beginning of period	$323.9	$295.7	$—	$—
Actual return on plan assets	20.1	48.4	—	—
Employer contributions	1.2	10.8	3.9	3.0
Plan participants' contributions	—	—	0.9	0.8
Benefit payments	(25.3)	(22.8)	(4.8)	(3.8)
Settlement payments	(14.3)	(8.2)	—	—
Fair value of plan assets, end of period	$305.6	$323.9	$—	$—

The Company’s overall investment strategy for its retirement plan trusts is to maintain investments in a diversified portfolio, comprised of primarily equity and fixed income investments, which are further diversified among various asset classes. The diversification is designed to minimize the risk of large losses while maximizing total return within reasonable and prudent levels of risk. The investment objectives specify a targeted investment allocation for the pension plans of 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 that 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 56 percent and 37 percent, respectively, of their fair value as of December 31, 2014 and approximately 53 percent and 42 percent, respectively, as of December 31, 2013. 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 $155.6 million at December 31, 2014 and $161.7 million at December 31, 2013. 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, 2014 and 2013, the estimate of undiscounted funds necessary to satisfy John Hancock’s remaining obligation was $3.8 million and $3.7 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, 2014 and 2013 was 4.12 percent and 4.75 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, 2014 and December 31, 2013 by asset category and by fair value hierarchy are as follows:

	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

	As of December 31, 2013			
(In millions)	Level 1	Level 2	Level 3	Total
Domestic equities & equity funds	$69.6	$85.6	$—	$155.2
International equities & equity funds	41.9	—	—	41.9
Domestic bonds & bond funds	40.4	55.4	—	95.8
Inflation protected security fund	—	12.1	—	12.1
Real estate, commodities & other	6.2	8.6	4.1	18.9
Total plan investments	$158.1	$161.7	$4.1	$323.9

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

(In millions)	2014	2013
Fair value, beginning of year	$4.1	$3.9
Unrealized gains related to investments still held at reporting date	0.1	0.2
Purchases, sales and settlements, net	—	—
Fair value, end of year	$4.2	$4.1

Funded Status

The funded status of the plans as of December 31, 2014 and 2013 follows:

	Pension Benefits		Other Benefits	
(In millions)	2014	2013	2014	2013
Qualified Plans				
Benefit obligation, end of period	$(351.7)	$(321.0)	$(53.3)	$(51.4)
Fair value of plan assets, end of period	305.6	323.9	—	—
Funded Status of Qualified Plans, end of period	(46.1)	2.9	(53.3)	(51.4)
Benefit obligation of SERP Plan, end of period	(20.2)	(17.5)	—	—
Total funded status, end of period	$(66.3)	$(14.6)	$(53.3)	$(51.4)
Accrued liabilities	$1.2	$1.0	$4.6	$4.9
Deferred credits & other liabilities	$65.1	$20.1	$48.7	$46.4
Other Assets	$—	$6.5	$—	$—

Expected Cash Flows

In 2015, the Company anticipates making $20 million in contributions to its qualified pension plans. In addition, the Company expects to make payments totaling approximately $1.2 million directly to SERP participants and approximately $3.5 million directly to those participating in the postretirement plan.

Estimated retiree pension benefit payments, including the SERP, projected to be required during the years following 2014 are approximately (in millions) $24.7 in 2015, $25.7 in 2016, $36.1 in 2017, $26.7 in 2018, $27.8 in 2019, and $143.8 in years 2020-2024. Expected benefit payments projected to be required for postretirement benefits during the years following 2014 (in millions) are approximately $4.6 in 2015, $4.7 in 2016, $4.8 in 2017, $5.1 in 2018, $5.4 in 2019, and $28.8 in years 2020-2024.

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

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

(In millions)	Pensions Prior Service Cost	Pensions Net Gain or Loss	Other Benefits Prior Service Cost	Other Benefits Net Gain or Loss	Other Benefits Transition Obligation
Balance at January 1, 2012	$5.4	$116.6	$(1.2)	$9.1	$2.7
Amounts arising during the period	0.7	26.4	(24.4)	2.8	(2.2)
Reclassification to benefit costs	(1.6)	(6.8)	2.5	(0.7)	(0.5)
Balance at December 31, 2012	$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	$—

Following is a reconciliation of the amounts in Accumulated other comprehensive income (AOCI) and Regulatory assets related to retirement plan obligations at December 31, 2014 and 2013.

(In millions)	2014 Pensions	2014 Other Benefits	2013 Pensions	2013 Other Benefits
Prior service cost	$2.0	$(17.1)	$3.0	$(20.1)
Unamortized actuarial gain/(loss)	111.7	10.9	67.3	8.1
Transition obligation	—	—	—	—
	113.7	(6.2)	70.3	(12.0)
Less: Regulatory asset deferral	(111.4)	6.1	(68.9)	11.8
AOCI before taxes	$2.3	$(0.1)	$1.4	$(0.2)

Related to pension plans, $1.0 million of prior service cost and $8.5 million of actuarial gain/loss is expected to be amortized to cost in 2015. Related to other benefits, $0.7 million of actuarial gain/loss is expected to be amortized to periodic cost in 2015, and $3.0 million of prior service cost is expected to reduce costs in 2015.

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 $32.4 million, $33.2 million and $27.6 million for the years ended

December 31, 2014, 2013, and 2012, respectively. During 2014, 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 2015 through 2017. The average contribution related to these local unions was less than $0.2 million, and the largest contribution was $4.1 million. Multiple unions can contribute to a single multiemployer plan. The Company made contributions to at least 50 plans in 2014, four 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 2014 and 2013 is for the plan year end at January 31, 2014 and 2013 for the Central Pension Fund, December 31, 2013 and 2012 for the Pipeline Industry Benefit Fund, May 31, 2014 and 2013 for the Indiana Laborers Pension Fund, and December 31, 2013 and 2012 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 2014, 2013, and 2012.

(In millions)

		Pension Protection Act Zone Status			Multiemployer Contributions			
Pension Fund	EIN/Pension Plan Number	2014	2013	FIP/RP Status Pending/Implemented	2014	2013	2012	Surcharge Imposed
Central Pension Fund	36-6052390-001	Green	Green	No	$7.7	$8.5	$4.0	No
Pipeline Industry Benefit Fund	73-0742835-001	Green	Green	No	5.1	5.3	3.9	No
Indiana Laborers Pension Fund (1)	35-6027150-001	Yellow	Yellow	Implemented	3.5	2.4	3.2	No
Minnesota Laborers Pension Fund	41-6159599-001	Green	Green	No	2.2	2.8	2.0	No
Other					13.9	14.2	14.5	
Total Contributions					$32.4	$33.2	$27.6	

(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 thirty-three percent of the way to 100 percent over a ten-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. If the Plan is in endangered or critical status for the plan year ended May 31, 2015, separate notification of the status has or will be provided.

While not considered significant to the Company, there are eight plans in red zone status receiving Company contributions. There are also four 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 2014, 2013 and 2012, the Company made contributions to these plans of $9.1 million, $7.5 million, and $6.7 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)	2014	2013
Utility Holdings		
Fixed Rate Senior Unsecured Notes		
2015, 5.45%	75.0	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
2041, 5.99%	35.0	35.0
2042, 5.00%	100.0	100.0
2043, 4.25%	80.0	80.0
Total Utility Holdings	875.0	875.0
Indiana Gas		
Fixed Rate Senior Unsecured Notes		
2015, Series E, 7.15%	5.0	5.0
2015, Series E, 6.69%	5.0	5.0
2015, Series E, 6.69%	10.0	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	116.0	116.0
SIGECO		
First Mortgage Bonds		
2015, 1985 Pollution Control Series A, current adjustable rate 0.05%, tax-exempt, 2013 weighted average: 0.10%	—	9.8
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, 1998 Pollution Control Series A, current adjustable rate 0.05%, tax-exempt, 2013 weighted average: 0.10%	—	31.5
2025, 2014 Series B, current adjustable rate 0.722%, tax-exempt	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, 4.0%, tax-exempt	22.2	22.2
2040, 2009 Environmental Improvement Series, 5.40%, tax-exempt	—	22.3
2043, 2013 Series B, 4.05%, tax-exempt	39.6	39.6
2044, 2014 Series A, 4.00% tax-exempt	22.3	—

Total SIGECO	267.5	267.5

87

(In millions)	At December 31, 2014	2013
Vectren Capital Corp.		
Fixed Rate Senior Unsecured Notes		
2014, 6.37%	—	30.0
2015, 5.31%	75.0	75.0
2016, 6.92%	60.0	60.0
2017, 3.48%	75.0	75.0
2019, 7.30%	60.0	60.0
2025, 4.53%	50.0	50.0
Variable Rate Term Loans		
2015	—	100.0
2016	—	100.0
Total Vectren Capital Corp.	320.0	550.0
Total long-term debt outstanding	1,578.5	1,808.5
Current maturities of long-term debt	(170.0)	(30.0)
Unamortized debt premium & discount - net	(1.2)	(1.4)
Total long-term debt-net	$1,407.3	$1,777.1

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 $100.0 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.

Vectren Capital 2012 Term Loan
On November 1, 2012, 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 November 2012 and repaid the loan in August 2014.

Utility Holdings 2012 Debt Transactions
On February 1, 2012, Utility Holdings issued $100 million of senior unsecured notes at an interest rate of 5.00 percent per annum and with a maturity date of February 3, 2042. The notes were sold to various institutional investors pursuant to a private placement note purchase agreement executed in November 2011 with a delayed draw feature. These senior notes are unsecured and jointly and severally guaranteed by Utility Holdings’ regulated utility subsidiaries, SIGECO, Indiana Gas, and VEDO. The proceeds from the sale of the notes, net of issuance costs, totaled approximately $99.5 million. These notes have no sinking fund requirements and interest payments are due semi-annually. These notes contain customary representations, warranties and covenants, including a leverage covenant consistent with leverage covenants contained in other Utility Holdings’ borrowing arrangements.

Mandatory Tenders

At December 31, 2014, certain series of SIGECO bonds, aggregating $49.1 million, currently bear interest at fixed rates and are subject to mandatory tender in September 2017. 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 intends to meet the 2014 sinking fund requirement by this means and, accordingly, the sinking fund requirement for 2014 is excluded from Current liabilities in the Consolidated Balance Sheets. At December 31, 2014, $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 $3.0 billion at December 31, 2014.

Consolidated maturities of long-term debt during the five years following 2014 (in millions) are $170.0 in 2015, $73.0 in 2016, $75.0 in 2017, $100.0 in 2018, $60.0 in 2019, and $1,099.3 thereafter.

Debt Guarantees
Vectren Corporation guarantees Vectren Capital's long-term debt, including current maturities, and short-term debt, which totaled $320 million and $0 million, respectively, at December 31, 2014. 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, 2014, totaled $875 million and $156 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, 2014 the Company was in compliance with all financial covenants.

Short-Term Borrowings
At December 31, 2014, the Company has $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 $194 million was available for the Utility Group operations and approximately $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.

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

	Utility Group Borrowings			Nonutility Group Borrowings		
(In millions)	2014	2013	2012	2014	2013	2012
As of Year End						
Balance Outstanding	$156.4	$28.6	$116.7	$—	$40.0	$162.1
Weighted Average Interest Rate	0.50 %	0.29 %	0.40 %	N/A	1.27 %	1.35 %
Annual Average						
Balance Outstanding	$35.6	$119.6	$77.6	$34.5	$119.3	$151.5
Weighted Average Interest Rate	0.34 %	0.34 %	0.47 %	1.29 %	1.35 %	1.44 %
Maximum Month End Balance Outstanding	$156.4	$176.1	$214.2	$76.3	$173.8	$216.1

Throughout 2014, 2013, and 2012, the Company has placed commercial paper without any significant issues and did not borrow from Utility Holdings' backup credit facility in any of the periods presented.

13. Common Shareholders' Equity

Authorized, Reserved Common and Preferred Shares
At December 31, 2014 and 2013, 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 5.3 million shares at December 31, 2014 and 5.8

million shares at December 31, 2013 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, 2014 and 2013, there were 392.2 million and 391.7 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 and for facilitating acquisitions.

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, 2014:

	Year Ended December 31,		
(In millions, except per share data)	2014	2013	2012
Numerator:			
Numerator for basic EPS	$166.9	$136.6	$159.0
Add back earnings attributable to participating securities	—	—	—
Reported net income (Numerator for Diluted EPS)	$166.9	$136.6	$159.0
Denominator:			
Weighted average common shares outstanding (Basic EPS)	82.5	82.3	82.0
Conversion of share based compensation arrangements	0.0	0.1	0.1
Adjusted weighted average shares outstanding and assumed conversions outstanding (Diluted EPS)	82.5	82.4	82.1
Basic earnings per share	$2.02	$1.66	$1.94
Diluted earnings per share	$2.02	$1.66	$1.94

For the years ended December 31, 2014 , 2013, and 2012, all options and equity based instruments were dilutive.

15. Accumulated Other Comprehensive Income

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

(In millions)	2012 Beginning of Year Balance	Changes During Year	End of Year Balance	2013 Changes During Year	End of Year Balance	2014 Changes During Year	End of Year Balance
Unconsolidated affiliates	$(15.9)	$11.3	$(4.6)	$4.6	$—	$—	$—
Pension & other benefit costs	(6.6)	4.0	(2.6)	1.4	(1.2)	(1.0)	(2.2)
Cash flow hedges	0.1	(0.1)	—	—	—	—	—
Deferred income taxes	9.1	(6.2)	2.9	(2.4)	0.5	0.4	0.9
Accumulated other comprehensive income (loss)	$(13.3)	$9.0	$(4.3)	$3.6	$(0.7)	$(0.6)	$(1.3)

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 Company 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 has in the past issued stock options and both performance-based and time-based awards. All share-based compensation programs are shareholder approved. Currently, awards issued to officers of the Company, which comprise a substantial majority of the awards issued, are performance-based, are generally settled in cash, and dividends that accrue are also subject to performance measures. In addition, the Company maintains a deferred compensation plan for executives 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:

(In millions)	Year Ended December 31, 2014	2013	2012
Total cost of share-based compensation	$25.2	$14.8	$6.3
Less capitalized cost	5.3	2.8	1.2
Total in other operating expense	19.9	12.0	5.1
Less income tax benefit in earnings	7.9	4.8	2.1
After tax effect of share-based compensation	$12.0	$7.2	$3.0

Performance Based Awards & Other Awards

The vesting of awards issued to Company officers and certain non-officer employees is contingent upon meeting total return and return on equity performance objectives. Historically, grants to Company officers and certain non-officer employees generally vested at the end of a four-year period, with performance measured at the end of the third year. Grants issued to Company officers and certain non-officer employees 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 for non-officer employees are time-vested awards and vest ratably over a three or five-year period. 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. Because Company officers and non-employee directors have the choice of settling awards in cash or deferring their receipt into a deferred compensation plan (where the value is eventually withdrawn in cash), these awards are accounted for as liability awards at their settlement date fair value. Share awards to certain non-officer employees must be settled in shares and are therefore 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, 2014, and changes during the year ended December 31, 2014, follows:

	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

As of December 31, 2014, there was $16.5 million of total unrecognized compensation cost associated with outstanding grants. That cost is expected to be recognized over a weighted-average period of 1.9 years. The total fair value of shares vested for liability awards during the years ended December 31, 2014, 2013, and 2012, was $15.1 million, $5.7 million, and $4.4 million, respectively. The total fair value of equity awards vesting during the year ended December 31, 2014, 2013, and 2012 was $0.9 million, $0.4 million, $0.1 million, respectively.

Stock Option Plans

In the past, option awards were granted to executives and other key employees with an exercise price equal to the market price of the Company's stock at the date of grant; those option awards generally required three years of continuous service and have 10-year contractual terms. These awards generally vested on a pro-rata basis over three years. The last option grant occurred in 2005, and the Company has no plans to issue options in the future. All compensation cost has been recognized.

The total intrinsic value of options exercised during the year ended December 31, 2014 , 2013, and 2012 was $0.1 million, $3.8 million, and $0.1 million respectively and the actual tax benefit realized for tax deductions from these option exercises was approximately $0.2 million, $1.5 million, and $0.1 million in 2014, 2013, and 2012, respectively. As of December 31, 2014, there are 946 exercisable shares remaining.

Deferred Compensation Plans

The Company has nonqualified deferred compensation plans, which permit eligible executives 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. At December 31, 2014 and 2013, the liability associated with these plans totaled $31.2 million and $26.1 million, respectively. Other than $1.4 million and $1.6 million which are classified in Accrued liabilities at December 31, 2014 and 2013, respectively, the liability is included in Deferred credits & other liabilities. The impact of these plans on Other operating expenses was expense of $5.0 million in 2014, $4.0 million in 2013 and $1.7 million in 2012. The amount recorded in earnings related to the investment activities in Vectren phantom stock associated with these plans during the years ended December 31, 2014, 2013, and 2012, was a cost of $4.0 million, $2.6 million and $0.6 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 $32.3 million and $32.9 million at December 31, 2014 and 2013, respectively. Earnings from those investments, which are recorded in Other income-net, were earnings of $2.8 million in 2014, $4.8 million in 2013, and $1.8 million in 2012.

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 2014 and thereafter (in millions) are $8.2 in 2015, $5.6 in 2016, $3.2 in 2017, $2.0 in 2018, $1.6 in 2019, and $3.6 thereafter. Total lease expense (in millions) was $13.2 in 2014, $9.9 in 2013, and $8.5 in 2012.

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.

Corporate Guarantees

The Company issues parent level guarantees to certain vendors and customers of its wholly owned subsidiaries and unconsolidated affiliates. These guarantees do not represent incremental consolidated obligations; rather, they represent parental guarantees of subsidiary and unconsolidated affiliate obligations in order to allow those subsidiaries and affiliates the flexibility to conduct business without posting other forms of collateral. At December 31, 2014, parent level guarantees, excluding guarantees of obligations of the federal business unit acquired from Chevron USA on April 1, 2014, as further described below, support a maximum of $25 million of Energy System Group's (ESG) performance contracting commitments and warranty obligations and $35 million of other project guarantees.

On April 1, 2014, ESG acquired the federal sector energy services unit of CES, from Chevron USA. Pursuant to the agreement, the acquisition includes a provision whereby Vectren Enterprises, Inc., the wholly owned holding company for the Company's nonutility investments, provided CES with an indemnification for potential claims against the seller that could arise related to the performance of work undertaken by ESG.

The acquisition also includes ESG guarantees of performance under certain assumed contracts. The guarantees include energy savings that are used to satisfy project financing. The Company guarantees ESG's performance under these energy savings guarantees. The total maximum amount of the energy savings guarantees is approximately $140 million and will only be called upon in the event energy savings established under the existing contracts executed by CES are not achieved. 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 Vectren Enterprises, Inc. provision providing indemnification to CES and the Company guarantee of the Keenan Ft. Detrick Energy operations agreement with Keenan as discussed above, do not state a maximum guarantee. Due to the nature of work performed under these contracts, the Company cannot estimate a maximum potential amount of future payments.

In addition, the Company has approximately $17 million of other guarantees outstanding supporting other consolidated subsidiary operations, of which $11 million represents letters of credit supporting other nonutility operations.

While there can be no assurance that neither the Vectren Enterprises, Inc.'s indemnification nor the Company guarantee provisions will be called upon, the Company believes that the likelihood of a material amount being triggered under any of these provisions is remote.

Performance Guarantees & Product Warranties

In the normal course of business, wholly owned subsidiaries, including ESG, issue performance bonds or other forms of assurance that commit them to timely install infrastructure, operate facilities, pay vendors or subcontractors, and/or support warranty obligations. Based on a history of meeting performance obligations and installed products operating effectively, no significant liability or cost has been recognized for the periods presented.

Specific to ESG, in its role as a general contractor in the performance contracting industry, at December 31, 2014, there are 50 open surety bonds supporting future performance. The average face amount of these obligations is $6.9 million, and the largest obligation has a face amount of $57.3 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, 2014, approximately 42 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. The Company has no accruals for these warranty and energy obligations as of December 31, 2014.

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 & Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement

The Company monitors and maintains its natural gas distribution system to ensure that 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 in both Indiana and Ohio were passed that 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, 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 and of the investment, as well as property taxes and operating expenses. The remaining 20 percent of project costs is 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. By allowing for the deferral of costs, such as depreciation, property taxes, and debt-related post in service carrying costs until recovery is approved by the Ohio Commission.

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 project to three years after being placed into service at SIGECO and four years after being placed into service at Indiana Gas. At December 31, 2014 and 2013, the Company has regulatory assets totaling $16.4 million and $12.1 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, discussed further below.

Requests for Recovery Under Indiana Regulatory Mechanisms
On August 27, 2014, the Commission issued an Order approving the Company’s seven-year capital infrastructure replacement and improvement plan, beginning in 2014, and the proposed accounting authority and recovery, pursuant to Senate Bill 251 and 560. 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 associated with pipeline safety rules, with 80 percent of the costs 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 update the seven-year capital investment plan annually, with detailed estimates provided for the upcoming calendar year. 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 Indiana Office of Utility Consumer Counselor (OUCC) filed a Notice of Appeal with the Indiana Court of Appeals in response to the IURC's Order. On January 28, 2015, the OUCC filed its appellate brief raising an issue regarding the treatment of retired assets within the recovery mechanism. An appeal was also filed in response to the IURC's Order in Northern Indiana Public Service Company's (NIPSCO) Senate Bill 560 electric infrastructure proceeding, pertaining to certain issues regarding the Commission's authority to approve NIPSCO's infrastructure plan. The outcome of neither appeal and the implications to the Company’s Order, if any, cannot be determined.

On January 14, 2015, the Commission issued an Order approving the Company’s initial request for recovery of the revenue requirement associated with capital investment and applicable operating costs through June 30, 2014 as part of its approved seven-year plan. As the next step of the recovery process, as outlined in the legislation, this Order initiates the rates and charges necessary to begin cash recovery of 80 percent of the revenue requirement, with the remaining 20 percent deferred for recovery in the Company's next rate cases. Also, consistent with the guidelines set forth in the original August 2014 Order, the Commission 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 cost increases. The updated plan reflects capital expenditures of approximately $900 million, an increase of $35 million from the previous plan and is inclusive of an estimated $30 million of economic development related expenditures, over the seven-year period beginning in 2014. The plan also includes approximately $15 million of annual operating costs associated with pipeline safety rules.

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 to be earned 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 $150.5 million. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $13.1 million and $9.3 million at December 31, 2014 and December 31, 2013, 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, subject to the graduated caps on the fixed DRR monthly charge applicable to residential and small general service customers approved in the Order. 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 May 1, 2014, the Company filed its annual request to adjust the DRR for recovery of costs incurred through December 31, 2013. On August 27, 2014 the PUCO issued an Order approving the Company’s revised DRR rates and charges, effective September 1, 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 three-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, 2014, 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, 2014, which covers the Company’s capital expenditure program through calendar year 2014. During 2014 and 2013, these approved capital expenditure programs under House Bill 95 generated Other income associated with the debt-related post-in-service carrying costs totaling $3.9 million and $2.2 million, respectively. Deferral of depreciation and property tax expenses related to these programs in 2014 and 2013 totaled $3.1 million and $1.7 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 has modified its position in testimony filed on November 5, 2014, and now suggests a reduced disallowance of $3 million. The Commission has moved this specific issue to a sub-docket proceeding, and based on the procedural schedule, an order is expected later in 2015. The Company believes that the costs are either recoverable in its GCA, or that if the incentive mechanism calculation is found to create a credit due to customers, any such outcome would be funded by its supply administrator. The administrator has intervened and filed testimony in the proceeding.

Indiana Gas & SIGECO Gas Decoupling Extension Filing

On August 18, 2011, the IURC issued an Order granting the extension of the current decoupling mechanism in place at both Indiana gas companies and recovery of new conservation program costs through December 2015. The Order provides that the companies must submit an extension proposal no later than March 1, 2015. The Companies have reached an agreement in principle with the OUCC to extend the decoupling mechanism through 2020. The final settlement will be filed for approval by the Commission by March 1, 2015.

19. Electric Rate & Regulatory Matters

SIGECO Electric Environmental Compliance Filing

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 mercury and air toxin standards effective in 2015 and to address an outstanding Notice of Violation (NOV) from the EPA. The total investment is estimated to be between $80 and $90 million, roughly half of which will be made to control mercury in both air and water emissions, and the remaining investment will be made to address the issues raised in the NOV proceeding on the increase in sulfur trioxide emissions. Although the Company and the Commission acknowledge that these investments are recoverable as clean coal technology under Senate Bill 29 and federal mandated investment under Senate Bill 251, the Order approves the Company’s request for deferred accounting treatment in lieu of timely recovery to avoid immediate customer bill impacts. 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 expected to occur in 2015 and 2016.

Coal Procurement Procedures
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. Those contracts were submitted to the IURC for review as part of the 2014 annual sub docket proceeding. In December 2014, the Commission determined that the terms of the coal contracts are reasonable. The annual sub docket proceeding is no longer required.

On December 5, 2011 within the quarterly FAC filing, SIGECO submitted a joint proposal with the OUCC to reduce its fuel costs billed to customers by accelerating into 2012 the impact of lower cost coal under new term contracts effective after 2012. The cost difference was deferred to a regulatory asset and is being recovered over a 6 year period without interest beginning in 2014. The IURC approved this proposal on January 25, 2012, with the reduction to customer's rates effective February 1, 2012. The total balance deferred for recovery through the Company's FAC, which began February 2014, was $42.4 million, of which $35.3 million remains as of December 31, 2014.

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; and 4) deferral of lost margin up to $3 million in 2012 and $1 million in 2011 associated with small customer DSM programs for subsequent recovery under a tracking mechanism to be proposed by the Company. On June 20, 2012, the IURC issued an Order approving a small customer lost margin recovery mechanism, inclusive of all previous deferrals. This mechanism is an alternative to the electric decoupling proposal that was denied by the IURC in the Company's last base rate proceeding. For the twelve months ended December 31, 2014 and December 31, 2013, the Company recognized Electric utility revenue of $8.7 million and $5.0 million, respectively, associated with this approved lost margin recovery mechanism.

On March 28, 2014, Senate Bill 340 was signed into law. This legislation ended electric DSM programs on December 31, 2014 that have been conducted to meet the energy savings requirements established in the Commission's December 2009 Order. 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. Indiana's governor has requested that the Commission make new recommendations for energy efficiency programs to be proposed for 2015 and beyond, and has also asked the legislature to consider further legislation requiring some level of utility sponsored energy efficiency programs. The Company filed a request for Commission approval of a new portfolio of DSM programs on May 29, 2014 to be offered in 2015. On October 15, 2014, the Commission issued an Order approving a Settlement between the OUCC and the Company regarding the new portfolio of DSM programs effective January 2015.

FERC Return on Equity (ROE) Complaint
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 MISO and various MISO transmission owners, including SIGECO. The joint parties seek to reduce the 12.38 percent return on equity 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. The MISO transmission owners filed their response to the complaint on January 6, 2014, opposing any change to the return. As of December 31, 2014, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $143.6 million at December 31, 2014.

This joint complaint is 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 methodology set out in its June 19, 2014 decision.
In addition to the NETO ruling, the FERC acknowledged that the pending complaint raised against the MISO transmission owners is reasonable, and ordered the initiation of a formal settlement discussion, mediated by a FERC appointed judge, in November 2014. As of January 2015, a settlement was not reached, and the case will move to a formal evidentiary hearing before the FERC. A procedural schedule was set on January 22, 2015, which will define a targeted date of final resolution from the FERC. An initial decision is expected later in 2015, but the timing of the final order from the FERC is unknown at this time. The Company has established a reserve pending the outcome of this complaint.

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 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.

20. Environmental Matters

Indiana Senate Bill 251
Indiana Senate Bill 251 is also applicable to federal environmental mandates impacting SIGECO electric operations. The Company continues with its ongoing evaluation of the impact Senate Bill 251 may have on its operations, including applicability of the stricter regulations the EPA is currently considering involving air quality, fly ash disposal, cooling tower intake facilities, waste water discharges, and greenhouse gases. These issues are further discussed below.

Air Quality
Cross-State Air Pollution Rule
In July 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR). CSAPR was the EPA’s response to the US Court of Appeals for the District of Columbia’s (the Court) remand of the Clean Air Interstate Rule (CAIR). CAIR was originally established in 2005 as an allowance cap and trade program that required reductions from coal-burning power plants for NOX emissions beginning January 1, 2009 and SO2 emissions beginning January 1, 2010, with a second phase of reductions in 2015. In an effort to address the Court’s finding that CAIR did not adequately ensure attainment of pollutants in certain downwind states due to unlimited trading of SO2 and NOX allowances, CSAPR reduced the ability of facilities to meet emission reduction targets through allowance trading. CSAPR reductions were to be achieved with initial step reductions beginning January 1, 2012, and final compliance to be achieved in 2014. After a series of legal challenges, the United States Supreme Court upheld CSAPR in April 2014, and the EPA finalized a new deadline schedule for entities that must comply, with CSAPR’s first phase caps starting in 2015 and 2016, and the second phase in 2017. The Company is in full compliance with all requirements of CSAPR.

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. Reductions are to be achieved within three years of publication of the final rule in the Federal Register (April 2015). The EPA did not grant blanket compliance extensions but asserted that states have broad authority to grant one year extensions for individual electric generating units where potential reliability impacts have been demonstrated. Legal challenges to the MATS Rule continue. In July, a coalition of twenty-one states, including

Indiana, filed a petition for certiorari with the U.S. Supreme Court seeking review of the decision of the appellate court. On November 25, 2014, the U.S. Supreme Court agreed to hear the case, with a decision expected later in 2015.

Notice of Violation for A.B. Brown Power Plant

The Company received a notice of violation (NOV) from the EPA in November 2011 pertaining to its A.B. Brown generating station. The NOV asserts that 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. The Company reached a settlement in principle with the EPA to resolve the NOV. That settlement was contemplated in the plan filed and approved by the IURC on January 28, 2015 in the SIGECO Electric Environmental Compliance Filing.

Information Request
SIGECO and Alcoa Generating Corporation (AGC), a subsidiary of ALCOA, own a 300 MW Unit 4 at the Warrick Power Plant as tenants in common. AGC and SIGECO also share equally in the cost of operation and output of the unit. In January 2013, AGC received an information request from the EPA under Section 114 of the Clean Air Act for historical operational information on the Warrick Power Plant. In April 2013, ALCOA filed a timely response to the information request.

Ozone NAAQS
On November 26, 2014, the U.S. 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. The EPA has stated that it intends to finalize the rule by October 2015. Upon finalization, the EPA will then determine whether a particular region is in attainment with the new standard. While it is possible that counties in southwest Indiana could be declared in non-attainment with the new standard, and thus may 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.

Water
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. Costs for compliance with these final regulations should qualify as federally mandated regulatory requirements and be recoverable under Indiana Senate Bill 251 referenced above.

Under the Clean Water Act, the EPA sets technology-based guidelines for water discharges from new and existing facilities. The EPA is currently in the process of revising the existing steam electric effluent limitation guidelines that set the technology-based water discharge limits for the electric power industry. The EPA is focusing its rulemaking on wastewater generated primarily by pollution control equipment necessitated by the comprehensive air regulations. The EPA released proposed rules on April 19, 2013 however the rule is not yet finalized. At this time, it is not possible to estimate what potential costs may be required to meet these new water discharge limits, however costs for compliance with these regulations should qualify as federally mandated regulatory requirements and be recoverable under Senate Bill 251 referenced above.

Conclusions Regarding Air and Water Regulations
To comply with Indiana’s implementation plan of the Clean Air Act, the Company obtained authority from the IURC to invest in clean coal technology. Using this authorization, the Company invested approximately $411 million starting in 2001 with the last equipment being placed into service on January 1, 2010. The pollution control equipment included SCR systems, fabric filters, and an SO2 scrubber at its generating facility that is jointly owned with AGC. SCR technology is the most effective method of reducing NOX emissions where high removal efficiencies are required and fabric filters control particulate matter emissions. The unamortized portion of the $411

million clean coal technology investment was included in rate base for purposes of determining SIGECO's electric base rates approved in the latest base rate order obtained April 27, 2011. SIGECO's coal-fired generating fleet is 100 percent scrubbed for SO2 and 90 percent controlled for NOX.

Utilization of the Company's NOX and SO2 allowances can be impacted as regulations are revised and implemented. Most of these allowances were granted to the Company at zero cost; therefore, any reduction in carrying value that could result from future changes in regulations would be immaterial.

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 mercury and air toxin standards effective in 2015 and to address an outstanding Notice of Violation (NOV) from the EPA. The total investment is estimated to be between $80 and $90 million, roughly half of which will be made to control mercury in both air and water emissions, and the remaining investment will be made to address the issues raised in the NOV proceeding on the increase in sulfur trioxide emissions.

Coal Ash Waste Disposal & Ash Ponds
In June 2010, the EPA issued proposed regulations affecting the management and disposal of coal combustion products, such as ash generated by the Company's coal-fired power plants. The proposed rules more stringently regulate these byproducts and would likely increase the cost of operating or expanding existing ash ponds and the development of new ash ponds. The alternatives include regulating coal combustion by-products that are not being beneficially reused as hazardous waste. The EPA did not offer a preferred alternative, but took public comment on multiple alternative regulations.

In December 2014 the U.S. EPA released its final coal ash rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). At this time the final rule has not been published in the Federal Register and as such is not yet effective. Under the final rule the Company will be required to commence an enhanced groundwater monitoring program to determine whether its existing ash ponds must be closed or retrofitted with liners. The final rule allows beneficial reuse of ash and the Company will continue to beneficially reuse a majority of its ash. Legislation is currently being considered by Congress that would provide for enforcement of the federal program by states in lieu of citizen suits.

The Company originally estimated capital expenditures to comply with the alternatives in the proposal could be as much as $30 million, and such expenditures could exceed $100 million if the most stringent of the alternatives was selected. As the less stringent Subtitle D program was selected by U.S. EPA in the final rule, the Company expects capital expenditures to comply in the lower end of this range. Annual compliance costs could increase only slightly or be impacted by as much as $5 million. Costs for compliance with these regulations should qualify as federally mandated regulatory requirements and be recoverable under Senate Bill 251 referenced above.

Climate Change
In April 2007, the US Supreme Court determined that greenhouse gases (GHG's) meet the definition of "air pollutant" under the Clean Air Act and ordered the EPA to determine whether GHG emissions cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. The endangerment finding was finalized in December 2009, concluding that carbon emissions pose an endangerment to public health and the environment.

The EPA has finalized two sets of GHG regulations that apply to the Company's generating facilities. In 2009, the EPA finalized a mandatory GHG emissions registry which requires the reporting of emissions. The EPA has also finalized a revision to the Prevention of Significant Deterioration (PSD) and Title V permitting rules which would require facilities that emit 75,000 tons or more of GHG's a year to obtain a PSD permit for new construction or a significant modification of an existing facility. The EPA's PSD and Title V permitting rules for GHG's were upheld by the US Court of Appeals for the District of Columbia, and in June 2014 the US Supreme Court upheld the regulations with respect to applicability to major sources such as coal-fired power plants that are required to hold PSD construction and Title V air operating permits for other criteria pollutants.

While the Company has no plans to invest in new coal-fired generation, there is also a rule making and related legal challenge involving new source performance standards for new construction. This rulemaking must be finalized and withstand legal scrutiny in order for the EPA to implement its proposed new source performance standards for existing units discussed below.

In July 2013, the President announced a Climate Action Plan, which calls on the EPA to finalize the rule for new construction expeditiously and by June 2015 finalize, New Source Performance Standards (NSPS) for GHG's for existing electric generating units which would apply to the Company's power plants. States must have their implementation plans to the EPA no later than June 2016. On June 2, 2014, the EPA proposed its rule for states to regulate CO_2 emissions from existing electric generating units. The rule, when final, will require states to adopt plans that reduce CO_2 emissions by 30 percent from 2005 levels by 2030. The EPA provided an extended time frame for public commentary to December 1, 2014. The proposal sets state-specific

CO_2 emission rate-based CO_2 goals (measured in lb CO_2/MWh) and guidelines for the development, submission and implementation of state plans to achieve the state goals. These state-specific goals are calculated based upon 2012 average emission rates aggregated for all fossil fuel-based units in the state. For Indiana, the proposal uses a 2012 emission rate of 1,923 lb CO_2/MWh, and sets an interim goal of 1,607 lb CO_2/MWh and a final emission goal of 1,531 lb CO_2/MWh that must be met by 2030. Under this proposal, these CO_2 emission rate goals do not apply directly to individual units, or generating systems. They instead are state goals. As such, the state must establish a framework that will guide how compliance will be met on a statewide basis. The state's interim or "phase in" goal of 1,607 lb CO_2/MWh must be met as averaged over a ten-year period (2020 - 2029) with progress toward this goal to be demonstrated for every two rolling calendar years starting in 2020, with the first report due in 2022.

Under the proposal all states have unique goals based upon each state's mix of electric generating assets. The EPA is proposing a 20 percent reduction in Indiana's total CO_2 emission rate compared to 2012. At 20 percent Indiana's CO_2 emission rate reduction requirement is tied with West Virginia as the 9^{th} lowest reduction requirement. This is due in part to the EPA's attempt to recognize the existing generating resource mix in the state and take into account each state's ability to cost effectively lower its CO_2 emission rate through a portfolio approach including energy efficiency and renewables, improving power plant heat rates, and dispatching lower emitting fuel sources. Each state's goals were set by taking 2012 emissions data and applying four "building blocks" of emission rate improvements that the EPA asserts can be achieved by that state. These four building blocks constitute the EPA's determination of "Best System of Emission Reductions that has been adequately demonstrated," which defines the EPA's authority under § 111(d) for existing sources. When applied to each state, the portfolio approach leads to significant differences in requirements across state lines. With the exception of building block number 1 (heat rate improvement of 6 percent), other building blocks are tailored to individual states based upon each state's existing generating mix and what the EPA concluded a state could reasonably accomplish to reduce its CO_2 emission rate. The Company timely filed comments to the Clean Power Plan proposal on December 1, 2014. The State of Indiana also filed public comments, asking that the proposal be withdrawn. Despite having just been recently proposed and not expected to be finalized until summer of 2015, legal challenges to the EPA's proposal have begun. On July 31, 2014, litigation was filed by the state of Indiana and other parties challenging the rules which may delay the timing of approval of the various state plans. That litigation has been set for argument before the U.S. Court of Appeals for the D.C. circuit in April of 2015, with a decision expected later in the summer.

With respect to the state of Indiana, the four building blocks that support Indiana's goal are as follows:
(1) Heat rate (HR) improvements of 6 percent (this is consistently applied to all states).
(2) Increasing the dispatch of existing natural gas baseload generation sources to 70 percent.
(3) Renewable energy portfolio requirements of 5 percent (interim) and 7 percent (final).
(4) Energy efficiency / DSM that results in reductions of 1.5 percent annually starting in 2020, ending at a sustained 11 percent by 2030.

Under the proposal, Indiana may choose to implement a program based upon an annual average emission rate target or convert that target rate to a comparable CO_2 emission cap. Indiana is the 5^{th} 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. Since 2005, the Company's emissions of CO_2 have declined 23 percent (on a tonnage basis). These reductions have come from the retirement of FB Culley Unit 1, expiration of municipal contracts, electric conservation and 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. 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 1967 lbs CO_2/MWh to 1922 lbs CO_2/MWh, for a reduction of 3 percent. The Company's CO_2 emission rate of 1922 lbs/MWh is basically the same as the State's average

CO_2 emission rate of 1923 lb CO_2/MWh.

Impact of Legislative Actions & Other Initiatives is Unknown

If the regulations referenced above are finalized by the EPA, or if legislation requiring reductions in CO_2 and other GHG's or legislation mandating a renewable energy portfolio standard is adopted, such regulation could substantially affect both the costs and operating characteristics of the Company's fossil fuel generating plants and natural gas distribution businesses. At this time and in the absence of final legislation or rulemaking, 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. As the EPA moves toward finalization of the NSPS for existing sources and the State of Indiana begins formulation of its state implementation plan, the Company will continue to remain engaged with the state to develop a plan for compliance and have more information to enable it to better assess potential compliance costs with a final regulation. Costs to purchase allowances that cap GHG emissions or expenditures made to control emissions or lower carbon emission rates should be considered a federally mandated cost of providing electricity, and as such, the Company believes such costs and expenditures should be recoverable from customers through Senate Bill 251 as referenced above or Senate Bill 29, which was used by the Company to recover its initial pollution control investments.

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 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 $14.3 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, 2014 and 2013, approximately $3.6 million and $5.7 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

103

21. Fair Value Measurements

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

(In millions)	At December 31, 2014 Carrying Amount	2014 Est. Fair Value	2013 Carrying Amount	2013 Est. Fair Value
Long-term debt	$1,577.3	$1,754.5	$1,807.1	$1,895.2
Short-term borrowings & notes payable	156.4	156.4	68.6	68.6
Cash & cash equivalents	86.4	86.4	21.5	21.5

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, 2014 and 2013, the fair value for these financial instruments was not estimated. The carrying value of these investments at December 31, 2014 and 2013 was approximately $10.4 million.

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. Results in the Coal Mining segment include the results and loss on sale 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. In its 2014 periodic reports, the Company reports the Energy Marketing segment information for 2013 and 2012, 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 in 2013. Remaining assets in Energy Marketing relate to the investment in ProLiance Holdings, LLC as described in Note 7.

Corporate and Other includes unallocated corporate expenses such as advertising and charitable contributions, among other activities, that benefit the Company’s other operating segments. 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:

	Year Ended December 31,		
(In millions)	2014	2013	2012
Revenues			
Utility Group			
Gas Utility Services	$944.6	$810.0	$738.1
Electric Utility Services	624.8	619.3	594.9
Other Operations	38.3	38.1	40.1
Eliminations	(38.0)	(37.8)	(39.5)
Total Utility Group	1,569.7	1,429.6	1,333.6
Nonutility Group			
Infrastructure Services	779.0	783.5	663.6
Energy Services	129.8	91.3	117.7
Coal Mining	234.3	292.8	235.8
Other Businesses	—	—	0.5
Total Nonutility Group	1,143.1	1,167.6	1,017.6
Eliminations, net of Corporate & Other Revenues	(101.1)	(106.0)	(118.4)
Consolidated Revenues	$2,611.7	$2,491.2	$2,232.8
Profitability Measures - Net Income			
Utility Group Net Income			
Gas Utility Services	$57.0	$55.7	$60.0
Electric Utility Services	79.7	75.8	68.0
Other Operations	11.7	10.3	10.0
Total Utility Group Net Income	148.4	141.8	138.0
Nonutility Group Net Income (Loss)			
Infrastructure Services	43.1	49.0	40.5
Energy Services	(3.2)	1.0	5.7
Coal Mining	(21.1)	(16.0)	(3.5)
Energy Marketing	—	(37.5)	(17.6)
Other Businesses	(0.8)	(1.0)	(3.4)
Total Nonutility Group Net Income (Loss)	18.0	(4.5)	21.7
Corporate & Other Net Loss	0.5	(0.7)	(0.7)
Consolidated Net Income	$166.9	$136.6	$159.0

	Year Ended December 31,		
(In millions)	2014	2013	2012
Amounts Included in Profitability Measures			
Depreciation & Amortization			
Utility Group			
Gas Utility Services	$93.3	$90.5	$85.4
Electric Utility Services	85.7	84.0	81.3
Other Operations	24.1	21.9	23.3
Total Utility Group	203.1	196.4	190.0
Nonutility Group			
Infrastructure Services	36.2	28.8	20.7
Energy Services	3.9	1.7	1.9
Coal Mining	29.9	50.8	41.8
Other Businesses	0.3	0.1	0.2
Total Nonutility Group	70.3	81.4	64.6
Consolidated Depreciation & Amortization	$273.4	$277.8	$254.6
Interest Expense			
Utility Group			
Gas Utility Services	$34.9	$30.6	$31.8
Electric Utility Services	29.0	29.2	33.8
Other Operations	2.7	5.2	5.9
Total Utility Group	66.6	65.0	71.5
Nonutility Group			
Infrastructure Services	11.1	10.1	7.5
Energy Services	1.3	0.6	0.4
Coal Mining	7.5	9.8	11.5
Energy Marketing	—	2.2	4.8
Other Businesses	0.9	0.5	0.7
Total Nonutility Group	20.8	23.2	24.9
Corporate & Other	(0.7)	(0.3)	(0.4)
Consolidated Interest Expense	$86.7	$87.9	$96.0
Income Taxes			
Utility Group			
Gas Utility Services	$35.7	$36.6	$39.1
Electric Utility Services	48.1	48.3	46.4
Other Operations	(0.6)	0.4	(0.2)
Total Utility Group	83.2	85.3	85.3
Nonutility Group			
Infrastructure Services	28.9	34.3	29.6
Energy Services	(7.8)	(11.9)	(9.0)
Coal Mining	(21.8)	(14.6)	(8.6)
Energy Marketing	—	(23.3)	(11.7)
Other Businesses	(0.3)	(1.6)	(2.0)
Total Nonutility Group	(1.0)	(17.1)	(1.7)
Corporate & Other	(1.1)	(1.1)	(1.1)
Consolidated Income Taxes	$81.1	$67.1	$82.5

	Year Ended December 31,		
(In millions)	2014	2013	2012
Capital Expenditures			
Utility Group			
Gas Utility Services	$245.9	$150.5	$128.8
Electric Utility Services	92.4	100.0	108.8
Other Operations	23.3	25.8	16.2
Non-cash costs & changes in accruals	(10.9)	(15.2)	(7.8)
Total Utility Group	350.7	261.1	246.0
Nonutility Group			
Infrastructure Services	54.1	79.2	53.7
Energy Services	1.6	6.9	2.3
Coal Mining	41.9	46.2	63.8
Total Nonutility Group	97.6	132.3	119.8
Consolidated Capital Expenditures	$448.3	$393.4	$365.8

	At December 31,	
(In millions)	2014	2013
Assets		
Utility Group		
Gas Utility Services	$2,605.1	$2,287.9
Electric Utility Services	1,659.3	1,679.0
Other Operations, net of eliminations	163.7	173.9
Total Utility Group	4,428.1	4,140.8
Nonutility Group		
Infrastructure Services	541.6	465.8
Energy Services	87.1	63.0
Coal Mining	—	433.0
Energy Marketing	30.6	33.9
Other Businesses, net of eliminations and reclassifications	89.2	34.9
Total Nonutility Group	748.5	1,030.6
Corporate & Other	658.1	828.1
Eliminations	(672.4)	(896.9)
Consolidated Assets	$5,162.3	$5,102.6

23. Additional Balance Sheet & Operational Information

Inventories consist of the following:

	At December 31,	
(In millions)	2014	2013
Gas in storage – at LIFO cost	$40.5	$33.2
Coal & oil for electric generation - at average cost	33.8	16.5
Materials & supplies	42.5	57.3
Nonutility coal - at LIFO cost	—	26.2
Other	1.7	1.2
Total inventories	$118.5	$134.4

Based on the average cost of gas purchased during December, the cost of replacing inventories carried at LIFO cost exceeded that carrying value at December 31, 2014 by approximately $3.0 million. Based on the average cost of gas purchase and coal produced during December, the cost of replacing inventories carried at LIFO cost exceeded that carrying value at December 31, 2013 by $8.5 million.

Prepayments & other current assets consist of the following:

	At December 31,	
(In millions)	2014	2013
Prepaid gas delivery service	$40.7	$32.9
Deferred income taxes	16.3	13.9
Prepaid taxes	37.5	11.2
Other prepayments & current assets	16.4	17.6
Total prepayments & other current assets	$110.9	$75.6

Investments in unconsolidated affiliates consist of the following:

	At December 31,	
(In millions)	2014	2013
ProLiance Holdings, LLC	$20.5	$20.8
Other nonutility partnerships & corporations	2.7	3.0
Other utility investments	0.2	0.2
Total investments in unconsolidated affiliates	$23.4	$24.0

Other utility & corporate investments consist of the following:

	At December 31,	
(In millions)	2014	2013
Cash surrender value of life insurance policies	$32.3	$32.9
Municipal bond	3.1	3.4
Restricted cash & other investments	1.8	1.8
Other utility & corporate investments	$37.2	$38.1

Goodwill by operating segment follows:

	At December 31,	
(In millions)	2014	2013
Utility Group		
Gas Utility Services	$205.0	$205.0
Nonutility Group		
Infrastructure Services	55.2	55.2
Energy Services	29.7	2.1
Consolidated goodwill	$289.9	$262.3

Accrued liabilities consist of the following:

	At December 31,	
(In millions)	2014	2013
Refunds to customers & customer deposits	$51.3	$50.2
Accrued taxes	35.8	36.2
Accrued interest	19.1	20.0
Deferred compensation & post-retirement benefits	7.3	7.5
Accrued salaries & other	71.4	68.2
Total accrued liabilities	$184.9	$182.1

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

(In millions)	2014	2013
Asset retirement obligation, January 1	$41.3	$37.7
Accretion	1.7	2.2
Changes in estimates, net of cash payments	23.8	1.4
Vectren Fuels Retirement Obligation	(11.8)	—
Asset retirement obligation, December 31	55.0	41.3

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

	Year Ended December 31,		
(In millions)	2014	2013	2012
ProLiance Holdings, LLC	$(0.3)	$(57.7)	$(22.7)
Other	0.8	(2.0)	(0.6)
Total equity in earnings (losses) of unconsolidated affiliates	$0.5	$(59.7)	$(23.3)

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

	Year Ended December 31,		
(In millions)	2014	2013	2012
AFUDC – borrowed funds	$11.4	$5.9	$4.6
AFUDC – equity funds	3.2	0.8	0.4
Nonutility plant capitalized interest	—	0.5	1.8
Interest income, net	1.1	1.1	1.1
Other nonutility investment impairment charges	(1.0)	—	(2.7)
Cash surrender value of life insurance policies	2.8	4.8	1.8
All other income	2.2	4.6	1.3
Total other income (expense) – net	$19.7	$17.7	$8.3

Supplemental Cash Flow Information:

	Year Ended December 31,		
(In millions)	2014	2013	2012
Cash paid (received) for:			
Interest	$87.5	$91.0	$94.6
Income taxes	69.4	6.8	21.8

As of December 31, 2014 and 2013, the Company has accruals related to utility and nonutility plant purchases totaling approximately $20.2 million and $19.4 million, respectively.

24. Impact of Recently Issued Accounting Guidance

Revenue Recognition Guidance

In May 2014, the FASB issued new accounting guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for GAAP 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. For a public entity, the guidance is effective for annual reporting periods beginning after December 15, 2016, with early adoption not permitted. An entity should apply the amendments in this update retrospectively to each prior reporting period presented or

109

retrospectively with the cumulative effect of initially applying this update recognized at the date of initial application. The Company is currently evaluating the standard to understand the overall impact it 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 about discontinued operations 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 did not early adopt this guidance in accounting for the sale of its Coal Mining assets. The Company is currently evaluating the impact of this guidance, if any.

Accounting for Stock Compensation

In June 2014, the FASB issued new accounting guidance on accounting for share-based payments when the terms of an award provide that a performance target could be achieved after the requisite service period. These amendments provide explicit guidance on whether to treat a performance target that could be achieved after the requisite service period as a performance condition that affects vesting or as a non-vesting condition that affects the grant-date fair value of an award. This guidance is effective for annual periods and interim periods within those periods beginning after December 15, 2015, with early adoption permitted. The Company’s current practice for accounting for stock compensation follows the prescribed manner as suggested by the update. Adoption of this guidance will not have a material impact on the Company’s financial statements.

Financial Reporting of Going Concern

In August 2014, the FASB issued new accounting guidance with respect to reporting on an entity's ability to continue as a going concern. This new guidance requires management to assess an entity's ability to continue as a going concern by incorporating and expanding upon certain principles that are currently in U.S. auditing standards, which requires disclosure surrounding what constitutes substantial doubt for the entity, including disclosure of management's plans to mitigate and alleviate substantial doubt. This guidance is effective for annual periods beginning after December 15, 2016, and for annual and interim periods thereafter, with early application permitted. Adoption of this guidance will not have a material impact on the Company’s financial statements.

25. Quarterly Financial Data (Unaudited)

Information in any one quarterly period is not indicative of annual results due to the seasonal variations common to the Company’s utility operations. Note that at June 30, 2014, the Company recorded an estimated loss on the transaction related to the Vectren Fuels sale to Sunrise Coal, including costs to sell, of approximately $32 million, or $20 million after tax. At June 18, 2013, the Company recorded its share of the loss related to ProLiance exiting the natural gas marketing business 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. Summarized quarterly financial data for 2014 and 2013 follows:

(In millions, except per share amounts)	Q1	Q2	Q3	Q4
2014				
Operating revenues	$796.8	$542.5	$595.6	$676.8
Operating income	99.0	33.9	84.5	97.1
Net income (loss)	51.2	11.9	47.3	56.5
Earnings (loss) per share:				
Basic	$0.62	$0.14	$0.57	$0.68
Diluted	0.62	0.14	0.57	0.68
2013				
Operating revenues	$700.6	$531.0	$579.6	$680.0
Operating income	106.8	57.9	83.3	85.6
Net income (loss)	49.8	(5.8)	42.8	49.8
Earnings (loss) per share:				
Basic	$0.61	$(0.07)	$0.52	$0.60
Diluted	0.61	(0.07)	0.52	0.60

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Changes in Internal Controls over Financial Reporting

During the quarter ended December 31, 2014, there have been no changes to the Company’s internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of December 31, 2014, the Company conducted an evaluation under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer of the effectiveness and the design and operation of the Company's disclosure controls and procedures. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective as of December 31, 2014, to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is:

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

Management's Report on Internal Control over Financial Reporting

Vectren Corporation's management is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation under the framework in Internal Control — Integrated Framework (2013), the Company concluded that its internal control over financial reporting was effective as of December 31, 2014.

The effectiveness of internal control over financial reporting as of December 31, 2014, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included in Item 8 of this annual report.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by Part III, Item 10 of this Form 10-K is incorporated by reference herein, and made part of this Form 10-K, from the Company's Proxy Statement for its 2015 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission pursuant to Regulation 14A, within 120 days after the end of the fiscal year. The Company’s executive officers are the same as those named executive officers detailed in the Proxy Statement.

Corporate Code of Conduct

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

ITEM 11. EXECUTIVE COMPENSATION

Information required by Part III, Item 11 of this Form 10-K is incorporated by reference herein, and made part of this Form 10-K, from the Company's Proxy Statement for its 2015 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission pursuant to Regulation 14A, within 120 days after the end of the fiscal year.

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

Except with respect to equity compensation plan information of the Registrant, which is included herein, the information required by Part III, Item 12 of this Form 10-K is incorporated by reference herein, and made part of this Form 10-K, from the Company's Proxy Statement for its 2015 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission pursuant to Regulation 14A, within 120 days after the end of the fiscal year.

Shares Issuable under Share-Based Compensation Plans

As of December 31, 2014, the following shares were authorized to be issued under share-based compensation plans:

Plan category	A Number of securities to be issued upon exercise of outstanding options, warrants and rights		B Weighted average exercise price of outstanding options, warrants and rights		C Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))	
Equity compensation plans approved by security holders	946	(1)	$27.15	(1)	3,553,203	(2)
Equity compensation plans not approved by security holders	—		—		—	
Total	946		$27.15		3,553,203	

(1) Under the Vectren At-Risk Compensation Plan, the Company may buy shares on the open market during periods when there are no restrictions on insider transactions to fulfill these obligations.

(2) Effective January 1, 2015, 169,030 performance-based units were issued to management by the Compensation and Benefits Committee of the Board of Directors. In addition, the Company is expecting to grant an additional 172,069 performance awards measured during the three year performance period ending December 31, 2014 which do not vest, with limited exceptions, until December 31, 2015. These issuances are not included in the above table.

The At-Risk Compensation plan was approved by Vectren Corporation common shareholders after the merger forming Vectren and was most recently amended and reapproved at the 2011 annual meeting of shareholders.

ITEM 13. CERTAIN RELATIONSHIPS, RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information required by Part III, Item 13 of this Form 10-K is incorporated by reference herein, and made part of this Form 10-K, from the Company's Proxy Statement for its 2015 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission pursuant to Regulation 14A, within 120 days after the end of the fiscal year.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required by Part III, Item 14 of this Form 10-K is incorporated by reference herein, and made part of this Form 10-K, from the Company's Proxy Statement for its 2015 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission pursuant to Regulation 14A, within 120 days after the end of the fiscal year.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

List of Documents Filed as Part of This Report

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

Supplemental Schedules
For the years ended December 31, 2014, 2013, and 2012, the Company's Schedule II -- Valuation and Qualifying Accounts Consolidated Financial Statement Schedules is presented herein. The report of Deloitte & Touche LLP on the schedule may be found in Item 8. All other schedules are omitted as the required information is inapplicable or the information is presented in the Consolidated Financial Statements or related notes in Item 8.

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

Column A	Column B	Column C Additions		Column D	Column E
Description	Balance at Beginning of Year	Charged to Expenses	Charged to Other Accounts	Deductions from Reserves, Net	Balance at End of Year
(In millions)					
VALUATION AND QUALIFYING ACCOUNTS:					
Year 2014 – Accumulated provision for uncollectible accounts	$6.8	$7.3	$—	$8.1	$6.0
Year 2013 – Accumulated provision for uncollectible accounts	$6.8	$6.8	$—	$6.8	$6.8
Year 2012 – Accumulated provision for uncollectible accounts	$6.7	$8.2	$—	$8.1	$6.8
Year 2014 – Reserve for impaired notes receivable	$0.6	$—	$—	$0.6	$—
Year 2013 – Reserve for impaired notes receivable	$0.6	$—	$—	$—	$0.6
Year 2012 – Reserve for impaired notes receivable	$15.7	$0.5	$—	$15.6	$0.6
OTHER RESERVES:					
Year 2014 - Restructuring costs	$0.2	$—	$—	$0.2	$—
Year 2013 – Restructuring costs	$0.3	$—	$—	$0.1	$0.2
Year 2012 – Restructuring costs	$0.4	$—	$—	$0.1	$0.3

List of Exhibits

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

Vectren Corporation
Form 10-K
Attached Exhibits

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

Exhibit Number	Document
21.1	List of Company's Significant Subsidiaries
23.1	Consent of Independent Registered Public Accounting Firm
31.1	Chief Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Chief Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Calculation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase

INDEX TO EXHIBITS

3. Articles of Incorporation and By-Laws

3.1	Amended and Restated Articles of Incorporation of Vectren Corporation effective March 31, 2000. (Filed and designated in Current Report on Form 8-K filed April 14, 2000, File No. 1-15467, as Exhibit 4.1.)
3.2	Code of By-Laws of Vectren Corporation as Most Recently Amended as of November 6, 2014. (Filed and designated in Current Report on Form 8-K filed November 12, 2014, File No. 1-15467, as Exhibit 3.1.)

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

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

4.3	Indenture dated October 19, 2001, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated October 19, 2001, File No. 1-16739, as Exhibit 4.1); First Supplemental Indenture, dated October 19, 2001, between Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated October 19, 2001, File No. 1-16739, as Exhibit 4.2); Second Supplemental Indenture, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated November 29, 2001, File No. 1-16739, as Exhibit 4.1); Third Supplemental Indenture, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated July 24, 2003, File No. 1-16739, as Exhibit 4.1); Fourth Supplemental Indenture, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated November 18, 2005, File No. 1-16739, as Exhibit 4.1). Form of Fifth Supplemental Indenture, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas & Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated October 16, 2006, File No. 1-16739, as Exhibit 4.1). Sixth Supplemental Indenture, dated March 10, 2008, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank National Association (Filed and designated in Form 8-K, dated March 10, 2008, File No. 1-16739, as Exhibit 4.1)
4.4	Note Purchase Agreement, dated October 11, 2005, between Vectren Capital Corp. and each of the purchasers named therein. (Filed designated in Form 10-K for the year ended December 31, 2005, File No. 1-15467, as Exhibit 4.4.) First Amendment, dated March 11, 2009, to Note Purchase Agreement dated October 11, 2005, among Vectren Corporation, Vectren Capital, Corp. and each of the holders named herein. (Filed and designated in Form 8-K dated March 16, 2009 File No. 1-15467, as Exhibit 4.6)
4.5	Note Purchase Agreement, dated March 11, 2009, among Vectren Corporation, Vectren Capital, Corp. and each of the purchasers named therein. (Filed and designated in Form 8-K dated March 16, 2009 File No. 1-15467, as Exhibit 4.5)
4.6	Note Purchase Agreement, dated April 7, 2009, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company and Vectren Energy Delivery of Ohio, Inc. and the purchasers named therein. (Filed and designated in Form 8-K dated April 7, 2009 File No. 1-15467, as Exhibit 4.5)
4.7	Note Purchase Agreement, dated September 9, 2010, among Vectren Capital, Corp. and the purchasers named therein. (Filed and designated in Form 8-K dated September 10, 2010 File No. 1-15467, as Exhibit 4.1)
4.8	Note Purchase Agreement, dated April 5, 2011, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company and Vectren Energy Delivery of Ohio, Inc. and the purchasers named therein. (Filed and designated in Form 8-K dated April 8, 2011 File No. 1-15467, as Exhibit 4.1)
4.9	Note Purchase Agreement, dated November 15, 2011, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company and Vectren Energy Delivery of Ohio, Inc. and the purchasers named therein. (Filed and designated in Form 8-K dated November 17, 2011 File No. 1-15467, as Exhibit 4.1)
4.10	Note Purchase Agreement, dated December 20, 2012, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company and Vectren Energy Delivery of Ohio, Inc. and the purchasers named therein. (Filed and designated in Form 8-K dated December 21, 2012 File No.

	1-15467, as Exhibit 4.1)
4.11	Note Purchase Agreement, dated August 22, 2013, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, and Vectren Energy Delivery of Ohio, Inc., and the purchasers named therein. (Filed and designated in Form 8-K dated August 2, 2013, File No. 1-15467, as Exhibit 4.1)

10. Material Contracts

10.1	Vectren Corporation At Risk Compensation Plan effective May 1, 2001, (as most recently amended and restated as of May 1, 2011). (Filed and designated in Form 8-K dated May 17, 2011, File No. 1-15467, as Exhibit 10.1.)

10.2	Vectren Corporation Non-Qualified Deferred Compensation Plan, as amended and restated effective January 1, 2001. (Filed and designated in Form 10-K, for the year ended December 31, 2001, File No. 1-15467, as Exhibit 10.32.)
10.3	Vectren Corporation Non-Qualified Deferred Compensation Plan, effective January 1, 2005. (Filed and designated in Form 8-K dated September 29, 2008, File No. 1-15467, as Exhibit 10.3.)
10.4	Vectren Corporation Unfunded Supplemental Retirement Plan for a Select Group of Management Employees (As Amended and Restated Effective January 1, 2005). (Filed and designated in Form 8-K dated December 17, 2008, File No. 1-15467, as Exhibit 10.1.)
10.5	Vectren Corporation Specimen Waiver, effective October 3, 2013, to the Vectren Corporation Unfunded Supplemental Retirement Plan for a Select Group of Management Employees. (Filed and designated in Form 10-Q for the quarter ended September 30, 2013, File No. 1-15467, as Exhibit 10.1)
10.6	Vectren Corporation Nonqualified Defined Benefit Restoration Plan (As Amended and Restated Effective January 1, 2005). (Filed and designated in Form 8-K dated December 17, 2008, File No. 1-15467, as Exhibit 10.2.)
10.7	Vectren Corporation At Risk Compensation Plan stock unit award agreement for non-employee directors, effective May 1, 2009. (Filed and designated in Form 8-K, dated February 20, 2009, File No. 1-15467, as Exhibit 10.1)
10.8	Vectren Corporation At Risk Compensation Plan specimen unit award agreement for officers, effective January 31, 2013. (Filed and designated in Form 10-K for the year ended December 31, 2012, File No. 1-15467, as Exhibit 10.2)
10.9	Vectren Corporation At Risk Compensation Plan specimen unit award agreement for officers, effective January 17, 2014. (Filed in Form 10-K herewith as Exhibit 10.14)
10.10	Vectren Corporation specimen change in control agreement dated December 31, 2011. (Filed and designated in Form 8-K, dated January 5, 2012, File No. 1-15467, as Exhibit 10.1) The specimen agreement significantly differs among the named executive officers only to the extent change in control benefits are provided in the amount of three times base salary and bonus for Mr. Carl L. Chapman and two times base salary and bonus for Messer's Jerome A. Benkert, Jr., Ronald E. Christian, and William S. Doty.
10.11	Amendment Number One to the Vectren Corporation specimen change in control agreement dated December 31, 2012. (Filed and designated in Form 10-K for the year ended December 31, 2012, File No. 1-15467, as Exhibit 10.1)
10.12	Vectren Corporation specimen severance plan agreement dated December 31, 2011. (Filed and designated in Form 8-K, dated January 5, 2012 File No. 1-15467, as Exhibit 10.2) The severance plan differs among the named executive officers only to the extent where severance benefits are provided in the amount of two times base salary for Mr. Chapman and one and one half times base salary for Messer's Benkert, Christian, and Doty.
10.13	Coal Supply Agreement for Warrick 4 Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., effective January 1, 2009. Contract assigned from Vectren Fuels, Inc. to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 8-K dated January 5, 2009, File No. 1-15467, as Exhibit 10.1.)
10.14	Coal Supply Agreement for F.B. Culley Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., effective January 1, 2009. Contract assigned from Vectren Fuels, Inc. to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 8-K dated January 5, 2009, File No. 1-15467, as Exhibit 10.2.)
10.15	Coal Supply Agreement for A.B. Brown Generating Station for 410,000 tons between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., effective January 1, 2009. Contract assigned from Vectren Fuels, Inc. to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 8-K dated January 5, 2009, File No. 1-15467, as Exhibit 10.3.)

10.16	Coal Supply Agreement for A.B. Brown Generating Station for 1 million tons between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., effective January 1, 2009. Contract assigned from Vectren Fuels, Inc. to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 8-K dated January 5, 2009, File No. 1-15467, as Exhibit 10.4.)
10.17	Amendment to F.B. Culley and A.B. Brown Coal Supply Agreements dated December 21, 2009. Contract assigned from Vectren Fuels, Inc. to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 10-K, for the year ended December 31, 2009, File No. 1-15467, as Exhibit 10.1)
10.18	Amendment No. 1 to Coal Supply Agreement for Warrick 4 Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., effective October 31, 2011. Contract assigned from Vectren Fuels, Inc. to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 8-K dated November 1, 2011, File No. 1-15467, as Exhibit 10.1.) Portions of the document have been omitted and filed separately pursuant to a request for confidential treatment filed with the Securities and Exchange Commission which was granted.
10.19	Amendment No. 2 to Coal Supply Agreement for F.B. Culley Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., effective October 31, 2011. Contract assigned from Vectren Fuels, Inc. to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 8-K dated November 1, 2011, File No. 1-15467, as Exhibit 10.2.) Portions of the document have been omitted and filed separately pursuant to a request for confidential treatment filed with the Securities and Exchange Commission which was granted.
10.20	Amendment No. 2 to Coal Supply Agreement for A.B. Brown Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., effective October 31, 2011. Contract assigned from Vectren Fuels, Inc. to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 8-K dated November 1, 2011, File No. 1-15467, as Exhibit 10.3.) Portions of the document have been omitted and filed separately pursuant to a request for confidential treatment filed with the Securities and Exchange Commission which was granted.
10.21	Gas Sales and Portfolio Administration Agreement between Indiana Gas Company, Inc. and ProLiance Energy, LLC, effective April 1, 2012. Contract assigned to ETC ProLiance Energy, LLC on June 18, 2013. (Filed and designated in Form 10-K for the year ended December 31, 2012, File No. 1-15467, as Exhibit 10.3)
10.22	Gas Sales and Portfolio Administration Agreement between Southern Indiana Gas and Electric Company and ProLiance Energy, LLC, effective April 1, 2012. Contract assigned to ETC ProLiance Energy, LLC on June 18, 2013. (Filed and designated in Form 10-K for the year ended December 31, 2012, File No. 1-15467, as Exhibit 10.4)
10.23	Formation Agreement among Indiana Energy, Inc., Indiana Gas Company, Inc., IGC Energy, Inc., Indiana Energy Services, Inc., Citizens Energy Group, Citizens Energy Services Corporation and ProLiance Energy, LLC, effective March 15, 1996. (Filed and designated in Form 10-Q for the quarterly period ended March 31, 1996, File No. 1-9091, as Exhibit 10-C.)
10.24	Credit Agreement, dated September 30, 2010, among Vectren Utility Holdings, Inc., and each of the financial institutions named therein. (Filed and designated in Form 8-K dated October 5, 2010, File No. 1-15467, as Exhibit 10.1)
10.25	Severance Agreement dated July 15, 2013 by and between Vectren Corporation and John Bohls. (Filed and designated in Form 8-K, dated July 18, 2013, File No. 1-15467, as Exhibit 10.1)
10.26	Consulting Agreement dated July 17, 2013 by and between Vectren Corporation and John M. Bohls. (Filed and designated in Form 8-K, dated July 18, 2013, File No. 1-5467, as Exhibit 10.2)
10.27	Stock Purchase Agreement, dated June 30, 2014 among Sunrise Coal, LLC, Vectren Utility Services, Inc., and Vectren Fuels, Inc. (Filed and designated in Form 8-K, dated July 8, 2014, File No. 1-5467, as Exhibit 10.1)
10.28	

Amendment Number Two to the Vectren Corporation Change in Control Agreement (specimen), dated October 1, 2014. (Filed and designated in Form 8-K, dated September 29, 2014, File No. 1-5467, as Exhibit 10.1)

10.29	Credit Agreement, dated as of October 31, 2014, among Vectren Utility Holdings, Inc., as borrower (Vectren Utility); certain subsidiaries of Vectren Utility, as guarantors; Bank of America, N.A., as administrative agent, swing line lender and a letter of credit issuer; Wells Fargo Bank, National Association, JPMorgan Chase Bank, N.A. and MUFG Union Bank, N.A., as co-syndication agents and letter of credit issuers; and the other lenders named therein. (Filed and designated in Form 8-K, dated November 5, 2014, File No. 1-5467, as Exhibit 10.1)
10.30	Credit Agreement, dated as of October 31, 2014, among Vectren Capital, Corp., as borrower; Vectren Corporation, as guarantor; Wells Fargo Bank, National Association, as administrative agent, swing line lender and a letter of credit issuer; Bank of America, N.A., JPMorgan Chase Bank, N.A. and MUFG Union Bank, N.A., as co-syndication agents and letter of credit issuers; and the other lenders named therein. (Filed and designated in Form 8-K, dated November 5, 2014, File No. 1-5467, as Exhibit 10.2)
10.31	Vectren Corporation At Risk Compensation Plan Stock Unit Awards Award Agreement (Officer). (Filed and designated in Form 8-K, dated December 23, 2014, File No. 1-5467, as Exhibit 10.1)
10.32	Grant Agreement for Non-Employee Director Stock Grant, dated December 31, 2014. (Filed and designated in Form 8-K, dated January 2, 2015, File No. 1-5467, as Exhibit 10.1)

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

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

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

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

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

101 Interactive Data File

101.INS XBRL Instance Document (Filed herewith.)

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

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

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

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

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

SIGNATURES

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

VECTREN CORPORATION

Dated February 17, 2015 /s/ Carl L. Chapman
Carl L. Chapman,
Chairman, President, and Chief Executive Officer

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

Signature	Title	Date
/s/ Carl L. Chapman Carl L. Chapman	Chairman, President, and Chief Executive Officer (Principal Executive Officer)	February 17, 2015
/s/ M. Susan Hardwick M. Susan Hardwick	Senior Vice President and Chief Financial Officer (Principal Accounting and Financial Officer)	February 17, 2015
/s/ James H. DeGraffenreidt James H. DeGraffenreidt	Director	February 17, 2015
/s/ Niel C. Ellerbrook Niel C. Ellerbrook	Director	February 17, 2015
/s/ John D. Engelbrecht John D. Engelbrecht	Director	February 17, 2015
/s/ Anton H. George Anton H. George	Director	February 17, 2015

/s/ Martin C. Jischke Martin C. Jischke	Director	February 17, 2015

/s/ Robert G. Jones Robert G. Jones	Director	February 17, 2015
/s/ J. Timothy McGinley J. Timothy McGinley	Director	February 17, 2015
/s/ Patrick K. Mullen Patrick K. Mullen	Director	February 17, 2015
/s/ R. Daniel Sadlier R. Daniel Sadlier	Director	February 17, 2015
/s/ Michael L. Smith Michael L. Smith	Director	February 17, 2015
/s/ Jean L. Wojtowicz Jean L. Wojtowicz	Director	February 17, 2015