VECTREN CORP
Form 10-Q
May 07, 2015

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2015

OR

o 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	35-2086905
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

One Vectren Square, Evansville, IN 47708
(Address of principal executive offices)
(Zip Code)

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

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. ý Yes o 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).
ý Yes o No

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 o
Non-accelerated filer o (Do not check if a smaller reporting company) Smaller reporting company o

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

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

Common Stock- Without Par Value	82,628,697	April 30, 2015
Class	Number of Shares	Date

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:	Phone Number:	Investor Relations Contact:
One Vectren Square	(812) 491-4000	Robert L. Goocher
Evansville, Indiana 47708		Treasurer and Vice President, Investor Relations
		vvcir@vectren.com

Definitions

MCF / BCF: thousands / billions of cubic feet	IURC: Indiana Utility Regulatory Commission
BTU / MMBTU: British thermal units / millions of BTU	MISO: Midcontinent Independent System Operator
DOT: Department of Transportation	GCA: Gas Cost Adjustment
EPA: Environmental Protection Agency	MW: megawatts
FAC: Fuel Adjustment Clause	MWh / GWh: megawatt hours / thousands of megawatt hours (gigawatt hours)
FASB: Financial Accounting Standards Board	Kv: Kilovolt
FERC: Federal Energy Regulatory Commission	OUCC: Indiana Office of the Utility Consumer Counselor
GAAP: Generally Accepted Accounting Principles	PUCO: Public Utilities Commission of Ohio
IDEM: Indiana Department of Environmental Management	Throughput: combined gas sales and gas transportation volumes
ASC: Accounting Standards Codification	XBRL: eXtensible Business Reporting Language
MDth / MMDth: thousands / millions of dekatherms	AFUDC: allowance for funds used during construction

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	March 31, 2015	December 31, 2014
ASSETS		
Current Assets		
Cash & cash equivalents	$17.1	$86.4
Accounts receivable - less reserves of $7.3 & $6.0, respectively	243.3	196.0
Accrued unbilled revenues	144.4	164.8
Inventories	92.7	118.5
Recoverable fuel & natural gas costs	—	9.8
Prepayments & other current assets	46.5	110.9
Total current assets	544.0	686.4
Utility Plant		
Original cost	5,778.0	5,718.7
Less: accumulated depreciation & amortization	2,316.9	2,279.7
Net utility plant	3,461.1	3,439.0
Investments in unconsolidated affiliates	23.4	23.4
Other utility & corporate investments	37.5	37.2
Other nonutility investments	33.8	33.6
Nonutility plant - net	380.8	378.0
Goodwill - net	289.9	289.9
Regulatory assets	224.8	233.6
Other assets	40.1	41.2
TOTAL ASSETS	$5,035.4	$5,162.3

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

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

	March 31, 2015	December 31, 2014
LIABILITIES & SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$216.1	$248.9
Refundable fuel & natural gas costs	23.0	2.5
Accrued liabilities	190.5	184.9
Short-term borrowings	6.4	156.4
Current maturities of long-term debt	225.0	170.0
Total current liabilities	661.0	762.7
Long-term Debt - Net of Current Maturities	1,347.4	1,407.3
Deferred Credits & Other Liabilities		
Deferred income taxes	753.3	741.2
Regulatory liabilities	417.1	410.3
Deferred credits & other liabilities	222.7	234.2
Total deferred credits & other liabilities	1,393.1	1,385.7
Commitments & Contingencies (Notes 7, 10-12)		
Common Shareholders' Equity		
Common stock (no par value) – issued & outstanding 82.6 shares	717.5	715.7
Retained earnings	917.7	892.2
Accumulated other comprehensive (loss)	(1.3)	(1.3)
Total common shareholders' equity	1,633.9	1,606.6
TOTAL LIABILITIES & SHAREHOLDERS' EQUITY	$5,035.4	$5,162.3

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

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VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited – in millions, except per share amounts)

	Three Months Ended March 31,	
	2015	2014
OPERATING REVENUES		
Gas utility	$352.9	$443.6
Electric utility	153.9	163.0
Nonutility	199.4	190.2
Total operating revenues	706.2	796.8
OPERATING EXPENSES		
Cost of gas sold	172.0	270.9
Cost of fuel & purchased power	50.1	57.0
Cost of nonutility revenues	64.3	67.7
Other operating	231.1	207.6
Depreciation & amortization	62.9	73.8
Taxes other than income taxes	19.7	20.8
Total operating expenses	600.1	697.8
OPERATING INCOME	106.1	99.0
OTHER INCOME (EXPENSE)		
Equity in earnings (losses) of unconsolidated affiliates	—	(0.1)
Other income – net	5.6	4.3
Total other income	5.6	4.2
INTEREST EXPENSE	21.0	22.1
INCOME BEFORE INCOME TAXES	90.7	81.1
INCOME TAXES	33.7	29.9
NET INCOME AND COMPREHENSIVE INCOME	$57.0	$51.2
AVERAGE COMMON SHARES OUTSTANDING	82.6	82.4
DILUTED COMMON SHARES OUTSTANDING	82.6	82.5
EARNINGS PER SHARE OF COMMON STOCK:		
BASIC	$0.69	$0.62
DILUTED	$0.69	$0.62
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$0.380	$0.360

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

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

	Three Months Ended March 31, 2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$57.0	$51.2
Adjustments to reconcile net income to cash from operating activities:		
Depreciation & amortization	62.9	73.8
Deferred income taxes & investment tax credits	14.6	5.7
Provision for uncollectible accounts	3.3	2.3
Expense portion of pension & postretirement benefit cost	1.6	1.0
Other non-cash items - net	1.6	3.0
Changes in working capital accounts:		
Accounts receivable & accrued unbilled revenues	(30.2)	(4.9)
Inventories	25.8	29.1
Recoverable/refundable fuel & natural gas costs	30.3	(24.2)
Prepayments & other current assets	61.2	38.4
Accounts payable, including to affiliated companies	(27.6)	(20.0)
Accrued liabilities	5.6	19.2
Employer contributions to pension & postretirement plans	(20.9)	(0.9)
Changes in noncurrent assets	11.3	9.1
Changes in noncurrent liabilities	3.6	(0.8)
Net cash provided by operating activities	200.1	182.0
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from dividend reinvestment plan & other common stock issuances	1.6	1.7
Requirements for:		
Dividends on common stock	(31.5)	(29.7)
Retirement of long-term debt	(5.0)	(30.0)
Net change in short-term borrowings	(150.0)	(14.4)
Net cash used in financing activities	(184.9)	(72.4)
CASH FLOWS FROM INVESTING ACTIVITIES		
Proceeds from other collections	0.8	1.1
Requirements for capital expenditures, excluding AFUDC equity	(85.3)	(77.7)
Net cash used in investing activities	(84.5)	(76.6)
Net change in cash & cash equivalents	(69.3)	33.0
Cash & cash equivalents at beginning of period	86.4	21.5
Cash & cash equivalents at end of period	$17.1	$54.5

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

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VECTREN CORPORATION AND SUBSIDIARY COMPANIES
NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

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 over 585,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to over 143,000 electric customers and over 111,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to over 317,000 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. Enterprises has other legacy businesses that have invested in energy-related opportunities and services, real estate, and a leveraged lease, among other investments. All of the above are collectively referred to as the Nonutility Group.

2. Basis of Presentation

The interim condensed consolidated financial statements included in this report have been prepared by the Company, without audit, as provided in the rules and regulations of the Securities and Exchange Commission and include a review of subsequent events through the date the financial statements were issued. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been omitted as provided in such rules and regulations. The information in this report reflects all adjustments which are, in the opinion of management, necessary to fairly state the interim periods presented, inclusive of adjustments that are normal and recurring in nature. These condensed consolidated financial statements and related notes should be read in conjunction with the Company's audited annual consolidated financial statements for the year ended December 31, 2014, filed with the Securities and Exchange Commission on February 17, 2015, on Form 10-K. Because of the seasonal nature of the Company's operations, the results shown on a quarterly basis are not necessarily indicative of annual results.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates.

3. 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 periods presented in these financial statements.

	Three Months Ended March 31,	
(In millions, except per share data)	2015	2014
Numerator:		
Reported net income (Numerator for Basic and Diluted EPS)	$57.0	$51.2
Denominator:		
Weighted average common shares outstanding (Denominator for Basic EPS)	82.6	82.4
Conversion of share based compensation arrangements	0.0	0.1
Adjusted weighted average shares outstanding and assumed conversions outstanding (Denominator for Diluted EPS)	82.6	82.5
Basic EPS	$0.69	$0.62
Diluted EPS	$0.69	$0.62

For the three months ended March 31, 2015 and 2014, all options and equity based instruments were dilutive and immaterial.

4. Excise and 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, which totaled $11.7 million and $12.9 million in the three months ended March 31, 2015 and 2014, respectively, as a component of operating revenues. Expenses associated with excise and utility receipts taxes are recorded as a component of Taxes other than income taxes.

5. Retirement Plans & Other Postretirement Benefits

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 plan are aggregated under the heading “Pension Benefits.” The postretirement benefit plan is presented under the heading “Other Benefits.”

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Net Periodic Benefit Costs

A summary of the components of net periodic benefit cost follows and the amortizations shown below are primarily reflected in Regulatory assets as a majority of pension and other postretirement benefits are being recovered through rates.

	Three Months Ended March 31,			
	Pension Benefits		Other Benefits	
(In millions)	2015	2014	2015	2014
Service cost	$2.0	$1.8	$0.1	$0.1
Interest cost	3.6	3.9	0.5	0.5
Expected return on plan assets	(5.6)	(5.7)	—	—
Amortization of prior service cost	0.2	0.3	(0.7)	(0.7)
Amortization of transitional obligation	—	—	—	—
Amortization of actuarial loss	2.1	1.2	0.1	0.1
Settlement charge	—	—	—	—
Net periodic benefit cost	$2.3	$1.5	$—	$—

Employer Contributions to Qualified Pension Plans

As of March 31, 2015, the Company has made $20.0 million in contributions to its qualified pension plans. The Company does not anticipate making further contributions in 2015.

6. Supplemental Cash Flow Information

As of March 31, 2015 and December 31, 2014, the Company has accruals related to utility and nonutility plant purchases totaling approximately $12.6 million and $20.2 million, respectively.

7. Investment in ProLiance Holdings, LLC

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

The Company's investment in ProLiance at March 31, 2015, shown at its 61 percent ownership share, is as follows.

(In millions)	As of March 31, 2015
Cash	$4.5
Investment in LA Storage	21.8
Other midstream asset investment	4.3
Total investment in ProLiance	$30.6
Included in:	

Investments in unconsolidated affiliates	20.5
Other nonutility investments	10.1

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

Approximately 12 Bcf of the storage, which comprises three of the four FERC certified caverns, is fully tested but additional work is required to further develop the caverns. The timing and extent of development of these caverns is dependent on market conditions, including pricing, need for storage capacity, and development of the liquefied natural gas market, among other factors. As of March 31, 2015 and December 31, 2014, ProLiance's investment in the joint venture was $35.7 million and $35.4 million, respectively.

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 March 31, 2015, 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.

8. 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. The sale of Vectren Fuels did not meet the requirements under GAAP to qualify as discontinued operations since Vectren has significant continuing cash flows related to the purchase of coal from the buyer of these mines. After the exit of the coal mining business by Vectren, Sunrise has assumed Vectren Fuels' supply contracts and has also negotiated new contracts for similar quality coal that will result in the Company purchasing most of its coal supply from Sunrise.

9. Financing Activities

Indiana Gas Unsecured Note Retirement
On March 15, 2015, a $5.0 million Indiana Gas senior unsecured note matured. The Series E note carried a fixed interest rate of 7.15%. The repayment of debt was funded from the Company's short term credit facility.

10. Commitments & Contingencies

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

Specific to ESG, in its role as a general contractor in the performance contracting industry, at March 31, 2015, there are 47 open surety bonds supporting future performance. The average face amount of these obligations is $7.3 million, and the largest obligation has a face amount of $57.3 million, where construction related to the project is 95 percent complete. The maximum exposure from these obligations is limited by the level of work already completed and guarantees issued to ESG by various subcontractors. At March 31, 2015, approximately 36 percent of work was completed on projects with open surety bonds. A significant portion of these open surety bonds will be released within one year. In instances where ESG operates facilities, project guarantees extend over a longer period. In addition to its performance obligations, ESG also warrants the functionality of certain installed infrastructure generally for one year and the associated energy savings over a specified number of years.

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

Corporate Guarantees

The Company issues parent level guarantees to certain vendors and customers of its wholly owned subsidiaries. These guarantees do not represent incremental consolidated obligations; rather, they represent parental guarantees of subsidiary obligations in order to allow those subsidiaries the flexibility to conduct business without posting other forms of collateral. At March 31, 2015, parent level guarantees support a maximum of $195 million of ESG's performance contracting commitments, warranty obligations, project guarantees, and energy savings guarantees. Further, an energy facility operated by ESG and managed by Keenan Ft. Detrick Energy, LLC (Keenan), is governed by an operations agreement. All payment obligations to Keenan under this agreement are also guaranteed by the Company. The Company guarantee of the Keenan Ft. Detrick Energy operations agreement, does not state a maximum guarantee. Due to the nature of work performed under this contract, the Company cannot estimate a maximum potential amount of future payments.

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

While there can be no assurance that the Company guarantee provisions will be called upon, the Company believes that the likelihood of a material amount being triggered under any of these provisions is remote.

Commitments

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. Costs arising from these commitments, while significant, are pass-through costs, generally collected dollar-for-dollar from retail customers through regulator-approved cost recovery mechanisms.

Legal & 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.

11. 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 Condensed 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 March 31, 2015 and December 31, 2014, the Company has regulatory assets totaling $17.3 million and $16.4 million, respectively, associated with the deferral of depreciation and debt-related post-in-service carrying cost activities. Beginning in 2014, all bare steel and cast iron replacement activities are now part of the Company's seven-year capital investment plan filed pursuant to Senate Bill 251, discussed further below.

Requests for Recovery Under Indiana Regulatory Mechanisms

On August 27, 2014, the IURC 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, 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 annually update the seven-year capital investment plan. Finally, the Order approved the Company's proposal to recover eligible costs via a fixed monthly charge per residential customer.

On September 26, 2014, the OUCC filed an appeal of the IURC's finding that the remaining value of retired assets replaced during the infrastructure projects should not be netted against the cost being recovered in the tracking mechanism. In April 2015, the Indiana Court of Appeals issued an opinion on an appeal involving Northern Indiana Public Service Company's (NIPSCO) infrastructure cost recovery mechanism finding that the value of retired assets should not be netted against the current recovery of costs. Although the opinion is specific to NIPSCO, the Company believes this decision is a positive outcome related to its pending appeal.

Additionally, in the NIPSCO appeal, the IURC's approval of the reasonableness of that infrastructure investment plan was challenged. The Court found that NIPSCO had failed to provide sufficient detail regarding its planned projects after year one of the plan to support the IURC's approval. An industrial group has asked the Court of Appeals to now consider that issue as part of the pending appeal of the Company's Order. Given this issue was never raised during the Company's IURC case or on appeal during the briefing period, the Company believes the opportunity to raise this issue has been waived and has asked the Court to strike the filing. The Court should decide these issues later this year.

On January 14, 2015, the IURC issued an Order approving the Company’s initial request for recovery of the revenue requirement through June 30, 2014 as part of its approved seven-year plan. 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 IURC approved the Company’s update to its seven-year plan, to reflect changes to project prioritization as a result of both additional risk modeling and 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.

On April 1, 2015, the Company filed its second request for recovery of the revenue requirement associated with capital investment and applicable operating costs through December 31, 2014. A procedural schedule has not been set in this proceeding. The Company expects an order in this proceeding mid-year in 2015.

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 $156.5 million. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $14.2 million and $13.1 million at March 31, 2015 and December 31, 2014, respectively. Due to the expiration of the initial five-year term for the DRR in early 2014, the Company filed a request in August 2013 to extend and expand the DRR. On February 19, 2014, the PUCO issued an Order approving a Stipulation entered into by the PUCO Staff and the Company which provided for the extension of the DRR for the recovery of costs incurred through 2017 and expanded the types of investment covered by the DRR to include recovery of other infrastructure investments. The Order limits the resulting DRR fixed charge per month for residential and small general service customers to specific graduated levels over the next five years. The Company's five-year capital expenditure plan related to these infrastructure investments for calendar years 2013 through 2017 totals approximately $200 million. The capital expenditure plan is subject to the graduated caps on the fixed DRR monthly charge applicable to residential and small general service customers approved in the Order however is not expected to exceed those caps. In addition, the Order approved the Company's commitment that the DRR can only be further extended as part of a base rate case. On 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 March 31, 2015, the Company's deferrals have not reached this bill impact cap. In addition, the Orders approved the Company's proposal that subsequent requests for accounting authority will be filed annually in April. The Company submitted its most recent annual filing on April 30, 2014, which covers the Company’s capital expenditure program through calendar year 2014.

Other Regulatory Matters

Indiana Gas GCA Cost Recovery Issue

On July 1, 2014, Indiana Gas filed its recurring quarterly Gas Cost Adjustment (GCA) mechanism, which included recovery of gas cost variances incurred for the period January through March 2014. In August 2014, the OUCC filed testimony opposing the recovery of approximately $3.9 million of natural gas commodity purchases incurred during this period on the basis that a gas cost incentive calculation had not been properly performed. The calculation at issue is performed by the Company's supply administrator. In the winter period at issue, a pipeline force majeure event caused the gas to be priced at a location that was impacted by the extreme winter temperatures. After further review, the OUCC modified its position in testimony filed on

November 5, 2014, and suggested a reduced disallowance of $3 million. The IURC moved this specific issue to a sub-docket proceeding. On April 1, 2015, a stipulation and settlement agreement between the Company, the OUCC, and the Company's supply administrator was filed in this proceeding. Pending a final order from the IURC approving the stipulation, the agreement results in recovery of approximately $1.4 million of the disputed amount via the Company's GCA mechanism, with the remaining $1.6 million from the gas supply administrator.

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 Companies have reached an agreement in principle with the OUCC to extend the decoupling mechanism through 2020. The settlement was filed for approval on March 1, 2015. The settlement was unopposed and a hearing has been set for May 2015. The Company expects an order later in 2015.

12. 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. As of March 31, 2015, approximately $29 million has been spent on equipment to control mercury in both air and water emissions, and $16 million to address the issues raised in the NOV proceeding on the increase in sulfur trioxide emissions. The total investment is estimated to be between $80 and $90 million. The Order approved the Company's request for deferred accounting treatment, as supported by provisions under Indiana Senate Bill 29 (Senate Bill 29) and Senate Bill 251. The accounting treatment includes the deferral of depreciation and property tax expense related to these investments, accrual of post-in-service carrying costs, and deferral of incremental operating expenses related to compliance with these standards. The initial phase of the projects went into service in 2014, with the remaining investment expected to occur in 2015 and 2016. As of March 31, 2015, the Company has approximately $0.7 million deferred related to depreciation, property tax, and operating expense, and $0.3 million deferred related to post-in-service carrying costs.

In March 2015, the Company was notified that certain parties had filed a Notice of Appeal with the Indiana Court of Appeals in response to the IURC's Order. Appellate briefs will be presented to the Court later in 2015 and it is expected the Court will decide on these issues in the second half of this year.

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 IURC determined that the terms of the coal contracts were 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 $33.6 million remains as of March 31, 2015.

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 three months ended March 31, 2015 and 2014, the Company recognized Electric utility revenue of $2.3 million and $1.6 million, respectively, associated with this approved lost margin recovery mechanism.

On March 28, 2014, Indiana Senate Bill 340 was signed into law. This legislation ended electric DSM programs on December 31, 2014 that have been conducted to meet the energy savings requirements established in the IURC'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 IURC 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 IURC approval of a new portfolio of DSM programs on May 29, 2014 to be offered in 2015. On October 15, 2014, the IURC issued an Order approving a Settlement between the OUCC and the Company regarding the new portfolio of DSM programs effective January 2015, and new programs were implemented during the first quarter 2015. On May 6, 2015, Indiana's governor signed Indiana Senate Bill 412 into law requiring electricity suppliers to create and submit energy-efficiency plans to the IURC at least one time every three years. Senate Bill 412 also supports the recovery of all program costs, including lost revenues and financial incentives associated with those plans and approved by the IURC. The Company will make its first filing pursuant to this bill in May 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 March 31, 2015, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $142.8 million at March 31, 2015.

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. A settlement has not been reached, and the case will move to a formal evidentiary hearing before the FERC. A procedural schedule was set on January 22, 2015, which defines 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.

Separately, on January 6, 2015, the FERC approved a MISO transmission owner joint request for an adder to the approved ROE. Under FERC regulations, transmission owners that are part of a Regional Transmission Organization (RTO) such as 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.

13. Environmental Matters
Indiana Senate Bill 251
Senate Bill 251 is also applicable to federal environmental mandates impacting SIGECO electric operations in addition to the impact on its gas utility 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. 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 oral arguments completed, a decision is expected later in 2015. MATS compliance was required to commence April 16, 2015, and Company is in full compliance with all requirements of MATS.

Notice of Violation for A.B. Brown Power Plant
The Company received a NOV from the EPA in November 2011 pertaining to its A.B. Brown generating station. The NOV asserts 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.

Ozone NAAQS

On November 26, 2014, the EPA proposed to tighten the current National Ambient Air Quality Standard (NAAQS) for ozone from the current standard of 75 parts per billion (ppb) to a level with the range of 65 to 70 ppb. 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 December 2014 the 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). On April 17, 2015, the final rule was published in the Federal Register. Under the final rule the Company will be required to perform additional safety and structural assessments and an enhanced groundwater monitoring program to determine whether its existing ash ponds may

remain in operation, be closed, or retrofitted with liners. The final rule allows beneficial reuse of ash and the Company will continue to reuse a majority of its ash. Legislation is currently being considered by Congress that would provide for enforcement of the federal program by states.

Under the final CCR rule, the Company is required to complete a series of integrity assessments and groundwater monitoring studies to determine whether one or more of the Company's ash ponds can continue in service, or whether a pond must be retrofitted with liners or closed and bottom ash handling conversions completed. The Company estimates capital expenditures to comply with the alternatives in the final rule could range from minor additional capital expenditures, if the ponds are permitted to continue to operate, and could exceed $100 million if all existing ponds at both F.B. Culley and A.B. Brown generating stations must be closed and bottom ash conversions completed at each generating unit. The Company is in the process of evaluating the impact of this rule and any impact on its asset retirement obligation (ARO). It is expected that any 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. Indiana’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 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 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

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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. Oral arguments have been completed before the U.S. Court of Appeals for the D.C. Circuit, 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 5th largest carbon emitter in the nation in tons of CO_2 produced from electric generation. In 2013, Indiana's electric utilities generated 105.6 million tons of CO_2. The Company's share of that total was 6.3 million, or less than 6 percent. 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 F.B. 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 upon order between Indiana Gas and the IDEM, and a Record of Decision was issued by the IDEM in January 2000. The remaining sites have been submitted to the IDEM's Voluntary Remediation Program (VRP). The Company has identified its involvement in five manufactured gas plant sites in SIGECO's service territory, all of which are currently enrolled in the IDEM's VRP. The Company is currently conducting some level of remedial activities, including groundwater monitoring at certain sites.

The Company has accrued the estimated costs for further investigation, remediation, groundwater monitoring, and related costs for the sites. While the total costs that may be incurred in connection with addressing these sites cannot be determined at this time, the Company has recorded cumulative costs that it has incurred or reasonably expects to incur totaling approximately $43.4 million ($23.2 million at Indiana Gas and $20.2 million at SIGECO). The estimated accrued costs are limited to the Company's share of the remediation efforts and are therefore net of exposures of other potentially responsible parties (PRP).

With respect to insurance coverage, Indiana Gas has received approximately $20.8 million from all known insurance carriers under insurance policies in effect when these plants were in operation. Likewise, SIGECO has settlement agreements with all known insurance carriers and has received to date approximately $14.3 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 March 31, 2015 and December 31, 2014, approximately $3.5 million and $3.6 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

14. Impact of Recently Issued Accounting Principles

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 adopted this guidance on January 1, 2015. The Company did not early adopt this guidance in accounting for the sale of its Coal Mining assets. The adoption of this guidance had no impact on the Company's financial statements.

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 adoption permitted. Adoption of this guidance will not have a material impact on the Company's financial statements.

Amendments to the Consolidation Analysis
In February 2015, the FASB issued new accounting guidance on amendments to the consolidation analysis, which is intended to improve certain areas of consolidation guidance for legal entities such as limited partnerships, limited liability companies, and securitization structures. The ASU will reduce the number of consolidation models and will be effective for annual reporting periods beginning after December 15, 2015. Early adoption is permitted, including adoption in an interim period. The Company is currently evaluating the standard to understand the overall impact it will have on the financial statements, if any.

Simplifying the Presentation of Debt Issuance Costs
In April 2015, the FASB issued new accounting guidance on accounting for debt issuance costs which changes the presentation of debt issuance costs in financial statements. This ASU requires an entity to present such costs in the balance sheet as a direct deduction from the related debt liability rather than as an asset. Amortization of the costs will continue to be reported as interest expense. This ASU is effective for annual reporting periods beginning after December 15, 2015. Early adoption is permitted. The new guidance will be applied retrospectively to each prior period presented. The Company is currently evaluating the standard to understand the overall impact it will have on the financial statements. Adoption will have no impact on the Company's consolidated income statement.

15. Fair Value Measurements

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

	March 31, 2015		December 31, 2014	
(In millions)	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	$1,572.4	$1,754.5	$1,577.3	$1,754.5
Short-term borrowings	6.4	6.4	156.4	156.4
Cash & cash equivalents	17.1	17.1	86.4	86.4

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

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

Under current regulatory treatment, call premiums on reacquisition of utility-related long-term debt are generally recovered in customer rates over the life of the refunding issue or over a 15-year period. Accordingly, any reacquisition of this debt would not be expected to have a material effect on the Company's results of operations.

Because of the nature of certain other investments and lack of a readily available market, it is not practical to estimate the fair value of these financial instruments at specific dates without considerable effort and cost. At March 31, 2015 and December 31, 2014, the fair value for these financial instruments was not estimated. The carrying value of these investments was approximately $10.4 million at both March 31, 2015 and December 31, 2014, and is included in Other nonutility investments.

16. 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 transmission and 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 reports is comprised of three operating segments: Gas Utility Services, Electric Utility Services, and Other operations.

The Nonutility Group has historically reported the following segments: Infrastructure Services, Energy Services, Coal Mining, and Other Businesses. In the 2015 periodic reports, the 2014 results for the Coal Mining segment include the results of Vectren Fuels through August 29, 2014 when it exited the coal mining business through the sale of Vectren Fuels (see Note 8 for additional information on this transaction).

Corporate and Other includes unallocated corporate expenses such as advertising and charitable contributions, among other activities, that benefit the Company’s other operations. Net income is the measure of profitability used by management for all operations.

Information related to the Company’s reportable segments is summarized as follows:

	Three Months Ended March 31,	
(In millions)	2015	2014
Revenues		
Utility Group		
Gas Utility Services	$352.9	$443.6
Electric Utility Services	153.9	163.0
Other Operations	10.2	9.6
Eliminations	(10.1)	(9.6)
Total Utility Group	506.9	606.6
Nonutility Group		
Infrastructure Services	176.9	123.0
Energy Services	23.1	17.5
Coal Mining	—	81.5
Total Nonutility Group	200.0	222.0
Corporate & Other Group	0.2	0.3
Eliminations	(0.9)	(32.1)
Consolidated Revenues	$706.2	$796.8
Profitability Measure - Net Income (Loss)		
Utility Group Net Income		
Gas Utility Services	$40.4	$38.3
Electric Utility Services	19.2	19.3
Other Operations	3.4	3.7
Utility Group Net Income	63.0	61.3
Nonutility Group Net Income (Loss)		
Infrastructure Services	(2.6)	(5.3)
Energy Services	(3.1)	(3.0)
Coal Mining	—	(1.1)
Other Businesses	(0.2)	(0.3)
Nonutility Group Net (Loss)	(5.9)	(9.7)
Corporate & Other Group Net (Loss)	(0.1)	(0.4)
Consolidated Net Income	$57.0	$51.2

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS 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 585,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 143,000 electric customers and over 111,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to approximately 317,000 natural gas customers located near Dayton in west central Ohio.

The Company, through Vectren Enterprises, Inc. (Enterprises), is involved in nonutility activities in two primary business areas: Infrastructure Services and Energy Services. Infrastructure Services provides underground pipeline construction and repair services. Energy Services provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects. Prior to August 29, 2014, the Company had activities in a Coal Mining business through Vectren Fuels, Inc. (Vectren Fuels). Results in the financial statements include the results of Coal Mining through the date of sale of August 29, 2014, when the Company exited the coal mining business through the sale of Vectren Fuels. 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.

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. The following discussion and analysis should be read in conjunction with the unaudited condensed consolidated financial statements and notes thereto as well as the Company's 2014 annual report filed on Form 10-K.

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 regulatory utility operations between a Gas Utility Services operating segment and an Electric Utility Services operating segment. The activities of, and revenues and cash flows generated by, the Nonutility Group are closely linked to the utility industry, and the results of those operations are generally impacted by factors similar to those impacting the overall utility industry. In addition, there are other operations, referred to herein as Corporate and Other, that include unallocated corporate expenses such as advertising and charitable contributions, among other activities.

Results for the three months ended March 31, 2015 were earnings of $57.0 million, or $0.69 per share, compared to earnings of $51.2 million, or $0.62 per share for the three months ended March 31, 2014.

In 2014, excluding the results attributable to the Company's Coal Mining business, consolidated net income for the three months ended March 31, 2014 was $52.3 million, or $0.63 per share.

Results Related to the Coal Mining 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. Results from Coal Mining for the three months ended March 31, 2014, was a loss of $1.1 million.

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

Net income (loss) and earnings per share, excluding results from Coal Mining in 2014, the year of disposition, in total and by group, for the three months ended March 31, 2015 and 2014 follow:

	Three Months Ended March 31,	
(In millions, except per share data)	2015	2014
Net income (loss), excluding Coal Mining results*	$57.0	$52.3
Attributed to:		
Utility Group	63.0	61.3
Nonutility Group, excluding Coal Mining results*	(5.9)	(8.6)
Corporate & other	(0.1)	(0.4)
Basic EPS, excluding Coal Mining results*	$0.69	$0.63
Attributed to:		
Utility Group	0.76	0.74
Nonutility Group, excluding Coal Mining results*	(0.07)	(0.11)
Corporate & other	—	—

*Excludes Coal Mining Results in 2014

Utility Group
In the first quarter of 2015, the Utility Group earnings were $63.0 million, compared to $61.3 million in 2014. The increase of $1.7 million relates primarily to increases in gas utility margin from returns on the Indiana and Ohio infrastructure replacement programs.

Nonutility Group
The Nonutility group results for the first quarter of 2015 were a loss of $5.9 million, compared to a loss of $8.6 million in the prior year, excluding Coal Mining results. Infrastructure Services operates at a seasonal loss in the first quarter however the seasonal loss was lower in 2015 compared to 2014, due to the inability of work crews to complete their work as planned because of the adverse winter weather and related road restrictions during the first quarter in 2014.

Dividends

Dividends declared for the three months ended March 31, 2015, were $0.380 per share, compared to $0.360 per share for the same period in 2014.

Use of Non-GAAP Performance Measures and Per Share Measures

Results Excluding Coal Mining

This discussion and analysis contains non-GAAP financial measures that exclude the results related to Coal Mining in 2014 since the Company exited the coal mining business in 2014.

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

A material limitation associated with the use of these measures is that the measures that exclude Coal Mining 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 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 (loss) to those results excluding Coal Mining results in 2014.

	Three Months Ended March 31, 2014		
(In millions, except EPS)	GAAP Measure	Exclude Coal Mining Results	Non-GAAP Measure
Consolidated			
Net Income (Loss)	$51.2	$(1.1)	$52.3
Basic EPS	$0.62	$(0.01)	$0.63
Nonutility Group Net Income (Loss)	$(9.7)	$(1.1)	$(8.6)

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 Condensed Consolidated Statements of Income.

Results of Operations of the Utility Group

The Utility Group is comprised of Utility Holdings' operations, which consist 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 transmission and distribution services 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 and reclassifications for the three months ended March 31, 2015 and 2014, follow:

	Three Months Ended March 31,	
(In millions, except per share data)	2015	2014
OPERATING REVENUES		
Gas utility	$352.9	$443.6
Electric utility	153.9	163.0
Other	0.1	—
Total operating revenues	506.9	606.6
OPERATING EXPENSES		
Cost of gas sold	172.0	270.9
Cost of fuel & purchased power	50.1	57.0
Other operating	102.8	98.3
Depreciation & amortization	52.1	49.9
Taxes other than income taxes	19.1	20.1
Total operating expenses	396.1	496.2
OPERATING INCOME	110.8	110.4
OTHER INCOME - NET	4.9	3.9
INTEREST EXPENSE	16.6	16.7
INCOME BEFORE INCOME TAXES	99.1	97.6
INCOME TAXES	36.1	36.3
NET INCOME	$63.0	$61.3
CONTRIBUTION TO VECTREN BASIC EPS	$0.76	$0.74

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. For example, demand side management and conservation expenses for both the gas and electric utilities; MISO administrative expenses for the Company's electric operations; uncollectible expense associated with the Company's Ohio gas customers; and recoveries of state mandated revenue taxes in both Indiana and Ohio are included in these amounts. 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:

	Three Months Ended March 31,	
(In millions)	2015	2014
Gas utility revenues	$352.9	$443.6
Cost of gas sold	172.0	270.9
Total gas utility margin	$180.9	$172.7
Margin attributed to:		
Residential & commercial customers	$126.3	$123.2
Industrial customers	19.3	18.8
Other	3.4	3.6
Regulatory expense recovery mechanisms	31.9	27.1
Total gas utility margin	$180.9	$172.7
Sold & transported volumes in MMDth attributed to:		
Residential & commercial customers	62.2	65.6
Industrial customers	38.0	36.0
Total sold & transported volumes	100.2	101.6

Gas Utility margins were $180.9 million for the three months ended March 31, 2015, and compared to 2014, increased $8.2 million in the quarter. Margin from small customer growth and large customer usage increased $0.8 million compared to the first quarter of 2014. Additionally, margin was favorably impacted by the return from infrastructure replacement programs of $1.6 million in Indiana and $1.3 million in Ohio. Pass through margin increased $4.8 million in 2015 compared to the first quarter 2014 due to regulatory expense recovery rate increases.

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

	Three Months Ended March 31,	
(In millions)	2015	2014
Electric utility revenues	$153.9	$163.0
Cost of fuel & purchased power	50.1	57.0
Total electric utility margin	$103.8	$106.0
Margin attributed to:		
Residential & commercial customers	$63.7	$64.3
Industrial customers	26.8	26.0
Other	1.0	0.9
Regulatory expense recovery mechanisms	3.3	4.8
Subtotal: retail	$94.8	$96.0
Wholesale power & transmission system margin	9.0	10.0
Total electric utility margin	$103.8	$106.0
Electric volumes sold in GWh attributed to:		
Residential & commercial customers	702.6	719.1
Industrial customers	672.9	660.1
Other customers	6.1	6.0
Total retail volumes sold	1,381.6	1,385.2

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Retail

Electric retail utility margins were $94.8 million for the three months ended March 31, 2015, and compared to 2014, decreased by $1.2 million. Electric results, which are not protected by weather normalizing mechanisms, experienced a $0.9 million decrease in small customer margin related to weather as annualized heating degree days in the first quarter of 2015 were 105 percent of normal compared to 108 percent of normal in 2014. As conservation initiatives continue, in the first quarter 2015 compared to first quarter 2014, the Company's lost revenue recovery mechanism contributed increased margin of $0.6 million related to electric conservation programs. Margin from regulatory expense recovery mechanisms decreased $1.5 million in 2015 compared to 2014, driven primarily by a corresponding decrease in operating expenses associated with the electric conservation programs. Additionally, results reflect an increase in large customer usage of $0.6 million largely driven by an industrial customer coming on line in the Company's service territory in August 2014.

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:

	Three Months Ended March 31,	
(In millions)	2015	2014
MISO Transmission system sales	$6.5	$6.1
MISO Off-system sales	2.5	3.9
Total wholesale margin	$9.0	$10.0

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms, and other transmission system operations, totaled $6.5 million and $6.1 million during the three months ended March 31, 2015 and 2014, respectively. As of March 31, 2015, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $142.8 million at March 31, 2015. These projects include an interstate 345 Kv transmission line that connects the Company’s A.B. Brown Generating Station to a generating station in Indiana owned by Duke Energy to the north and to a generating station in Kentucky owned by Big Rivers Electric Corporation to the south; a substation; and another transmission line. Although the allowed return is currently being challenged as discussed below in Rate and Regulatory Matters, once placed into service, these projects earn a FERC approved equity rate of return of 12.38 percent on the net plant balance. Operating expenses are also recovered. The Company has established a reserve pending the outcome of 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.

For the three months ended March 31, 2015, margin from off-system sales was $2.5 million, compared to $3.9 million in 2014. The base rate changes implemented in May 2011 require that wholesale margin from off-system sales earned above or below $7.5 million per year be shared equally with customers. Results for the periods presented reflect the impact of that sharing as well as a decrease in volumes sold due to lower market pricing.

Utility Group Operating Expenses

Other Operating

For the three months ended March 31, 2015, other operating expenses were $102.8 million, an increase of $4.5 million, compared to 2014. The increase in other operating costs is primarily due to increases in costs that are recovered directly in margin. Excluding these pass through costs, other operating expenses decreased $0.4 million in 2015, compared to the same period in 2014, primarily driven by decreased energy delivery expenses due to the harsh winter weather in the first quarter 2014.

Depreciation & Amortization
In the first quarter of 2015, depreciation and amortization expense was $52.1 million, compared to $49.9 million in 2014. The increase reflects increased plant placed in service.

Taxes Other Than Income Taxes
For the first quarter, taxes other than income taxes were $19.1 million compared to $20.1 million for the period in 2014. The decrease of $1.0 million is primarily due to decreased revenue taxes. These taxes are primarily revenue-related taxes and are offset dollar-for-dollar with lower gas utility and electric utility revenues reflected in margin attributable to regulatory expense recovery mechanisms.

Other Income - Net

Other income-net reflects income of $4.9 million for the first quarter of 2015, an increase of $1.0 million, compared to 2014. The increase is due to higher AFUDC driven by increased capital expenditures related to infrastructure replacement investments, as well as higher AFUDC rates.

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 Condensed 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 March 31, 2015 and December 31, 2014, the Company has regulatory assets totaling $17.3 million and $16.4 million, respectively, associated with the deferral of depreciation and debt-related post-in-service carrying cost activities. Beginning in 2014, all bare steel and cast iron replacement activities are now part of the Company’s seven-year capital investment plan filed pursuant to Senate Bill 251, discussed further below.

Requests for Recovery Under Indiana Regulatory Mechanisms
On August 27, 2014, the IURC 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, 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 annually update the seven-year capital investment plan. Finally, the Order approved the Company’s proposal to recover eligible costs via a fixed monthly charge per residential customer.

On September 26, 2014, the OUCC filed an appeal of the IURC's finding that the remaining value of retired assets replaced during the infrastructure projects should not be netted against the cost being recovered in the tracking mechanism. In April 2015, the Indiana Court of Appeals issued an opinion on an appeal involving Northern Indiana Public Service Company’s (NIPSCO) infrastructure cost recovery mechanism finding that the value of retired assets should not be netted against the current recovery of costs. Although the opinion is specific to NIPSCO, the Company believes this decision is a positive outcome related to its pending appeal.

Additionally, in the NIPSCO appeal, the IURC’s approval of the reasonableness of that infrastructure investment plan was challenged. The Court found that NIPSCO had failed to provide sufficient detail regarding its planned projects after year one of the plan to support the IURC's approval. An industrial group has asked the Court of Appeals to now consider that issue as part of the pending appeal of the Company's Order. Given this issue was never raised during the Company's IURC case or on appeal during the briefing period, the Company believes the opportunity to raise this issue has been waived and has asked the Court to strike the filing. The Court should decide these issues later this year.

On January 14, 2015, the IURC issued an Order approving the Company’s initial request for recovery of the revenue requirement through June 30, 2014 as part of its approved seven-year plan. 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 IURC approved the Company’s update to its seven-year plan, to reflect changes to project prioritization as a result of both additional risk modeling and 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.

On April 1, 2015, the Company filed its second request for recovery of the revenue requirement associated with capital investment and applicable operating costs through December 31, 2014. A procedural schedule has not been set in this proceeding. The Company expects an order in this proceeding mid-year in 2015.

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 $156.5 million. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $14.2 million and $13.1 million at March 31, 2015 and December 31, 2014, respectively. Due to the expiration of the initial five-year term for the DRR in early 2014, the Company filed a request in August 2013 to extend and expand the DRR. On February 19, 2014, the PUCO issued an Order approving a Stipulation entered into by the PUCO Staff and the Company which provided for the extension of the DRR for the recovery of costs incurred through 2017 and expanded the types of investment covered by the DRR to include recovery of other infrastructure investments. The Order limits the resulting DRR fixed charge per month for residential and small general service customers to specific graduated levels over the next five years. The Company's five-year capital expenditure plan related to these infrastructure investments for calendar years 2013 through 2017 totals approximately $200 million. The capital expenditure plan is subject to the graduated caps on the fixed DRR monthly charge applicable to residential and small general service customers approved in the Order however is not expected to exceed those caps. In addition, the Order approved the Company's commitment that the DRR can only be further extended as part of a base rate case. On 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 March 31, 2015, the Company's deferrals have not reached this bill impact cap. In addition, the Orders approved the Company's proposal that subsequent requests for accounting authority will be filed annually in April. The Company submitted its most recent annual filing on April 30, 2014, which covers the Company’s capital expenditure program through calendar year 2014.

Other Regulatory Matters

Indiana Gas GCA Cost Recovery Issue

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

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

Companies have reached an agreement in principle with the OUCC to extend the decoupling mechanism through 2020. The settlement was filed for approval on March 1, 2015. The settlement was unopposed and a hearing has been set for May 2015. The Company expects an order later in 2015.

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. As of March 31, 2015, approximately $29 million has been spent on equipment to control mercury in both air and water emissions, and $16 million to address the issues raised in the NOV proceeding on the increase in sulfur trioxide emissions. The total investment is estimated to be between $80 and $90 million. The Order approved the Company's request for deferred accounting treatment, as supported by provisions under Indiana Senate Bill 29 (Senate Bill 29) and Senate Bill 251. The accounting treatment includes the deferral of depreciation and property tax expense related to these investments, accrual of post-in-service carrying costs, and deferral of incremental operating expenses related to compliance with these standards. The initial phase of the projects went into service in 2014, with the remaining investment expected to occur in 2015 and 2016. As of March 31, 2015, the Company has approximately $0.7 million deferred related to depreciation, property tax, and operating expense, and $0.3 million deferred related to post-in-service carrying costs.

In March 2015, the Company was notified that certain parties had filed a Notice of Appeal with the Indiana Court of Appeals in response to the IURC's Order. Appellate briefs will be presented to the Court later in 2015 and it is expected the Court will decide on these issues in the second half of this year.

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 IURC determined that the terms of the coal contracts were 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 $33.6 million remains as of March 31, 2015.

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 three months ended March 31, 2015 and 2014, the Company recognized Electric utility

revenue of $2.3 million and $1.6 million, respectively, associated with this approved lost margin recovery mechanism.

On March 28, 2014, Indiana Senate Bill 340 was signed into law. This legislation ended electric DSM programs on December 31, 2014 that have been conducted to meet the energy savings requirements established in the IURC'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 IURC 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 IURC approval of a new portfolio of DSM programs on May 29, 2014 to be offered in 2015. On October 15, 2014, the IURC issued an Order approving a Settlement between the OUCC and the Company regarding the new portfolio of DSM programs effective January 2015, and new programs were implemented during the first quarter 2015. On May 6, 2015, Indiana's governor signed Indiana Senate Bill 412 into law requiring electricity suppliers to create and submit energy-efficiency plans to the IURC at least one time every three years. Senate Bill 412 also supports the recovery of all program costs, including lost revenues and financial incentives associated with those plans and approved by the IURC. The Company will make its first filing pursuant to this bill in May 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 March 31, 2015, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $142.8 million at March 31, 2015.

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. A settlement has not been reached, and the case will move to a formal evidentiary hearing before the FERC. A procedural schedule was set on January 22, 2015, which defines 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.

Separately, on January 6, 2015, the FERC approved a MISO transmission owner joint request for an adder to the approved ROE. Under FERC regulations, transmission owners that are part of a Regional Transmission Organization (RTO) such as 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

Indiana Senate Bill 251
Senate Bill 251 is also applicable to federal environmental mandates impacting SIGECO electric operations in addition to the impact on its gas utility 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. 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 oral arguments completed, a decision is expected later in 2015. MATS compliance was required to commence April 16, 2015, and Company is in full compliance with all requirements of MATS.

Notice of Violation for A.B. Brown Power Plant

The Company received a NOV from the EPA in November 2011 pertaining to its A.B. Brown generating station. The NOV asserts 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.

Ozone NAAQS

On November 26, 2014, the EPA proposed to tighten the current National Ambient Air Quality Standard (NAAQS) for ozone from the current standard of 75 parts per billion (ppb) to a level with the range of 65 to 70 ppb. 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 December 2014 the 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). On April 17, 2015, the final rule was published in the Federal Register. Under the final rule the Company will be required to perform additional safety and structural assessments and an enhanced groundwater monitoring program to determine whether its existing ash ponds may remain in operation, be closed, or retrofitted with liners. The final rule allows beneficial reuse of ash and the Company will continue to reuse a majority of its ash. Legislation is currently being considered by Congress that would provide for enforcement of the federal program by states.

Under the final CCR rule, the Company is required to complete a series of integrity assessments and groundwater monitoring studies to determine whether one or more of the Company's ash ponds can continue in service, or whether a pond must be retrofitted with liners or closed and bottom ash handling conversions completed. The Company estimates capital expenditures to comply with the alternatives in the final rule could range from minor additional capital expenditures, if the ponds are permitted to continue to operate, and could exceed $100 million if all existing ponds at both F.B. Culley and A.B. Brown generating stations must be closed and bottom ash conversions completed at each generating unit. The Company is in the process of evaluating the impact of this rule and any impact on its asset retirement obligation (ARO). It is expected that any 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

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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. Indiana'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 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 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. Oral arguments have been completed before the U.S. Court of Appeals for the D.C. Circuit, 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 5th largest carbon emitter in the nation in tons of CO_2 produced from electric generation. In 2013, Indiana's electric utilities generated 105.6 million tons of CO_2. The Company's share of that total was 6.3 million, or less than 6 percent. 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 F.B. 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 upon order between Indiana Gas and the IDEM, and a Record of Decision was issued by the IDEM in January 2000. The remaining sites have been submitted to the IDEM's Voluntary Remediation Program (VRP). The Company has identified its involvement in five manufactured gas plant sites in SIGECO's service territory, all of which are currently enrolled in the IDEM's VRP. The Company is currently conducting some level of remedial activities, including groundwater monitoring at certain sites.

The Company has accrued the estimated costs for further investigation, remediation, groundwater monitoring, and related costs for the sites. While the total costs that may be incurred in connection with addressing these sites cannot be determined at this time, the Company has recorded cumulative costs that it has incurred or reasonably expects to incur totaling approximately $43.4 million ($23.2 million at Indiana Gas and $20.2 million at SIGECO). The estimated accrued costs are limited to the Company's share of the remediation efforts and are therefore net of exposures of other potentially responsible parties (PRP).

With respect to insurance coverage, Indiana Gas has received approximately $20.8 million from all known insurance carriers under insurance policies in effect when these plants were in operation. Likewise, SIGECO has settlement agreements with all known insurance carriers and has received to date approximately $14.3 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 March 31, 2015 and December 31, 2014, approximately $3.5 million and $3.6 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

Results of Operations of the Nonutility Group

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

The Nonutility Group results were a loss of $5.9 million for the three months ended March 31, 2015, compared to a loss of $9.7 million for the three months ended March 31, 2014. Nonutility Group results, excluding the results from Coal Mining in 2014, the year of disposition, for the three months ended March 31, 2015 and 2014 follow. See page 27 for a reconciliation of Non-GAAP performance measures.

	Three Months Ended March 31,	
(In millions, except per share amounts)	2015	2014
NET INCOME (LOSS) EXCLUDING COAL MINING RESULTS*	$(5.9)	$(8.6)
CONTRIBUTION TO VECTREN BASIC EPS, EXCLUDING COAL MINING RESULTS*	$(0.07)	$(0.11)
NET INCOME (LOSS) ATTRIBUTED TO:		
Infrastructure Services	$(2.6)	$(5.3)
Energy Services	(3.1)	(3.0)
Other Businesses	(0.2)	(0.3)

*Excludes Coal Mining Results in 2014

Infrastructure Services

Infrastructure Services provides underground pipeline construction and repair services through wholly-owned subsidiaries Miller Pipeline, LLC (Miller or Miller Pipeline) and Minnesota Limited, LLC (Minnesota Limited). Inclusive of holding company costs, results for Infrastructure Services' operations for the first quarter of 2015 were a loss of $2.6 million, compared to a loss of $5.3 million for the same period in the prior year.

Results in the first quarter of 2015 were improved as 2014 reflected the inability of crews to complete their work as planned because of the harsher winter weather. Backlog as of March 31, 2015 was $610 million. This compares to $625 million at December 31, 2014 which included significant station work that is now complete. Revenues during the first quarter of 2015 were $176.9 million, compared to revenues of $123.0 million for the same period in 2014. Demand continues to be strong as evidenced by increased revenue and a significant backlog.

The backlog amounts above include 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, and 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.

Construction activity remains strong as utilities, municipalities and pipeline operators replace aging natural gas and oil pipelines and related infrastructure and as pipeline operators construct new pipelines due to the continued significant demand for shale gas and oil infrastructure. The recent drop in oil prices has not had, and 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, pipelines are still being built for producing wells. While the drop in oil prices could have greater impact in 2016 if prices do not continue to rebound, the mix of activity is favorable and the long term trends are good.

On May 6, 2015, Miller Pipeline acquired A & B Trenching Co., Inc. in a strategic move to expand its markets and strengthen its position as a leader in the underground construction industry. This transaction marks Miller Pipeline's sixth acquisition within a ten-year time period and reinforces its geographic resources encompassing 26 states. The acquired company, North Carolina-based A & B Trenching Co Inc., has been in operation since 1985 as a specialty contractor focusing on distribution pipeline construction and maintenance, directional boring and fabrication services.

Energy Services

Energy Services provides energy performance contracting and sustainable infrastructure, such as distributed generation and combined heat and power projects through its wholly-owned subsidiary Energy Systems Group, LLC (ESG). Inclusive of holding company costs, for the three months ended March 31, 2015, Energy Services operated at a loss of $3.1 million, compared to a loss of $3.0 million in 2014.

The results in the first quarter of 2015 reflect the continued delay in closing awarded projects. However, focused efforts to improve the contract award-to-signing process continue. At March 31, 2015, the performance contracting backlog of signed contracts remains strong at $161 million, compared to $144 million on December 31, 2014.

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 to grow given the expected rise in power prices across the country and customer focus on efficiency. Expected activity in the federal sector, as well as positive indications in the public sector and sustainable infrastructure business, is reflected in the increased backlog and sales funnel.

Inclusive in the acquisition of the Federal Business Unit (FBU) from Chevron, USA on April 1, 2014, were several Indefinite Delivery / Indefinite Quantity contracts with federal government agencies including Energy Savings Performance Contracts (ESPC) with the US Department of Energy and US Army Corps of Engineers. On a periodic basis, the contracts are extended and/or subject to a recompete process. The recompete process for these two contracts is currently underway and management feels confident that both will be awarded to ESG.

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 Vectren Fuels, to Sunrise Coal, LLC (Sunrise Coal), an Indiana-based wholly owned subsidiary of Hallador Energy Company. On August 29, 2014, the transaction closed. Results from Coal Mining for the three months ended March 31, 2014, was a loss of $1.1 million.

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 adopted this guidance on January 1, 2015. The Company did not early adopt this guidance in accounting for the sale of its Coal Mining assets. The adoption of this guidance had no impact on the Company’s financial statements.

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 adoption permitted. Adoption of this guidance will not have a material impact on the Company’s financial statements.

Amendments to the Consolidation Analysis
In February 2015, the FASB issued new accounting guidance on amendments to the consolidation analysis, which is intended to improve certain areas of consolidation guidance for legal entities such as limited partnerships, limited liability companies, and securitization structures. The ASU will reduce the number of consolidation models and will be effective for annual reporting periods beginning after December 15, 2015. Early adoption is permitted, including adoption in an interim period. The Company is currently evaluating the standard to understand the overall impact it will have on the financial statements, if any.

Simplifying the Presentation of Debt Issuance Costs
In April 2015, the FASB issued new accounting guidance on accounting for debt issuance costs which changes the presentation of debt issuance costs in financial statements. This ASU requires an entity to present such costs in the balance sheet as a direct deduction from the related debt liability rather than as an asset. Amortization of the costs will continue to be reported as interest expense. This ASU is effective for annual reporting periods beginning after December 15, 2015. Early adoption is permitted. The new guidance will be applied retrospectively to each prior period presented. The Company is currently evaluating the standard to understand the overall impact it will have on the financial statements. Adoption will have no impact on the Company's consolidated income statement.

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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 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 March 31, 2015 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 SIGECO, Indiana Gas, and VEDO. Utility Holdings’ long-term debt, including current maturities, outstanding at March 31, 2015 approximated $875 million. As of March 31, 2015, Utility Holdings had $6 million in short-term borrowings outstanding. 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 March 31, 2015, was approximately $377 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 Investor Services (Moody's) does not provide a rating for Vectren Corporation. The credit ratings of the senior unsecured debt of Utility Holdings, SIGECO and Indiana Gas, at March 31, 2015, are 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 has a credit rating of A-2/P-1. The current outlook of both Moody’s and Standard and Poor’s is stable. A security rating is not a recommendation to buy, sell, or hold securities. The rating is subject to revision or withdrawal at any time, and each rating should be evaluated independently of any other rating. Standard and Poor’s and Moody’s lowest level investment grade rating is BBB- and Baa3, respectively.

The Company’s consolidated equity capitalization objective is 45-55 percent of long-term capitalization. This objective may have varied, and will vary, depending on particular business opportunities, capital spending requirements, execution of long-term financing plans, and seasonal factors that affect the Company’s operations. The Company’s equity component was 51 percent and 50 percent of long-term capitalization at March 31, 2015 and December 31, 2014, respectively. Long-term capitalization includes long-term debt, including current maturities, as well as common shareholders’ equity.

Both long-term and short-term borrowing arrangements contain customary default provisions; restrictions on liens, sale-leaseback transactions, mergers or consolidations, and sales of assets; and restrictions on leverage, among other restrictions. Multiple debt agreements contain a covenant that the ratio of consolidated total debt to consolidated total capitalization will not exceed 65 percent. As of March 31, 2015, the Company was in compliance with all debt covenants.

Available Liquidity

The Company’s A-/A2 investment grade credit ratings have allowed it to access the capital markets as needed, and 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 non-utility 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 15, 2015, a $5.0 million Indiana Gas senior unsecured note matured. The Series E note carried a fixed interest rate of 7.15%. The repayment of debt was funded from the Company's short term credit facility.

Consolidated Short-Term Borrowing Arrangements

At March 31, 2015, 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 $344 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)	2015	2014	2015	2014
As of March 31				
Balance Outstanding	$5.9	$—	$0.5	$54.2
Weighted Average Interest Rate	0.39%	n/a	1.30%	1.27%
Quarterly Average - March 31				
Balance Outstanding	$69.2	$1.9	$0.1	$25.9
Weighted Average Interest Rate	0.39%	0.26%	1.32%	1.29%
Maximum Month End Balance Outstanding	$121.5	$—	$0.5	$54.2

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 added additional liquidity of $1.6 million and $1.7 million in the three months ended March 31, 2015 and 2014, respectively.

Potential Uses of Liquidity

Pension Funding Obligations

For the three months ended March 31, 2015, the Company had contributed $20 million to its qualified pension plans. The Company does not anticipate making further contributions in 2015.

Performance Guarantees & Product Warranties

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

Specific to ESG, in its role as a general contractor in the performance contracting industry, at March 31, 2015, there are 47 open surety bonds supporting future performance. The average face amount of these obligations is $7.3 million, and the largest obligation has a face amount of $57.3 million, where construction related to the project is 95 percent complete. The maximum exposure from these obligations is limited by the level of work already completed and guarantees issued to ESG by various subcontractors. At March 31, 2015, approximately 36 percent of work was completed on projects with open surety bonds. A significant portion of these open surety bonds will be released within one year. In instances where ESG operates facilities, project guarantees extend over a longer period. In addition to its performance obligations, ESG also warrants the functionality of certain installed infrastructure generally for one year and the associated energy savings over a specified number of years.

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

Corporate Guarantees

The Company issues parent level guarantees to certain vendors and customers of its wholly owned subsidiaries. These guarantees do not represent incremental consolidated obligations; rather, they represent parental guarantees of subsidiary obligations in order to allow those subsidiaries the flexibility to conduct business without posting other forms of collateral. At March 31, 2015, parent level guarantees support a maximum of $195 million of ESG’s performance contracting commitments, warranty obligations, project guarantees, and energy savings guarantees. Further, an energy facility operated by ESG and managed by Keenan Ft. Detrick Energy, LLC (Keenan), is governed by an operations agreement. All payment obligations to Keenan under this agreement are also guaranteed by the Company. The Company guarantee of the Keenan Ft. Detrick Energy operations agreement, does not state a maximum guarantee. Due to the nature of work performed under this contract, the Company cannot estimate a maximum potential amount of future payments.

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

While there can be no assurance that the Company guarantee provisions will be called upon, the Company believes that the likelihood of a material amount being triggered under any of these provisions is remote.

Planned Capital Expenditures & Investments

Utility capital expenditures are estimated at $350 million for the remainder of 2015. Nonutility capital expenditures and investments are estimated at $40 million for the remainder of 2015.

Contractual Obligations

The Company’s contractual obligations primarily consist of debt issued by Indiana Gas, Utility Holdings, and Vectren Capital; certain plant and nonutility plant purchase commitments, and other long-term liabilities. For the three months ended March 31, 2015, there were no significant changes to the Company’s contractual obligations from those identified in the Company’s Annual Report on Form 10-K for the year ended December 31, 2014, other than those which occur in the normal and ordinary course of business and those mentioned below.

Comparison of Historical Sources & Uses of Liquidity

Operating Cash Flow

The Company's primary source of liquidity to fund working capital requirements has been cash generated from operations, which totaled $200.1 million and $182.0 million for the three months ended March 31, 2015 and 2014, respectively. The increase is driven primarily by changes in certain working capital accounts. Weather related impacts include the fluctuation in the recoverable/refundable natural gas and fuel cost. Additionally a decrease in prepaid taxes was due to a federal refund received in 2015 related to the extension of bonus depreciation in 2014. These increases in cash flow are somewhat offset by an increase in contributions to qualified pension plans and weather related increases in accounts receivable.

Financing Cash Flow

Net cash flow required for financing activities was $184.9 million during the three months ended March 31, 2015 compared to requirements of $72.4 million in 2014. The current year period, compared to first quarter of 2014, reflects a greater decrease of short term borrowings of $135.6 million. The prior year period reflects the retirement of $30 million in long-term debt, which was funded by the Company's short-term credit facilities. Financing activity in both periods presented reflects the payment of dividends.

Investing Cash Flow

Cash flow required for investing activities was $84.5 million and $76.6 million during the three months ended March 31, 2015 and 2014, respectively. The primary use of cash in both periods presented reflect expenditures for utility and nonutility capital expenditures.

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 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.
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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; changes in the timing of being awarded projects; credit worthiness of customers; lower energy prices negatively impacting the economics of performance contracting business; and changing market conditions.
- Employee or contractor workforce factors including changes in key executives, collective bargaining agreements with union employees, aging workforce issues, work stoppages, or pandemic illness.
- Risks associated with material business transactions such as acquisitions and divestitures, including, without limitation, legal and regulatory delays; the related time and costs of implementing such transactions; integrating operations as part of these transactions; and possible failures to achieve expected gains, revenue growth and/or expense savings from such transactions.
- Costs, fines, penalties and other effects of legal and administrative proceedings, settlements, investigations, claims, including, but not limited to, such matters involving compliance with federal and state laws and interpretations of these laws.
- 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 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to various business risks associated with interest rates, counter-party credit, and commodity prices. 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 use of derivatives. The Company executes derivative contracts in the normal course of operations while buying and selling commodities and occasionally 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.

These risks are not significantly different from the information set forth in Item 7A Quantitative and Qualitative Disclosures About Market Risk included in the Vectren 2014 Form 10-K and is therefore not presented herein.

ITEM 4. CONTROLS AND PROCEDURES

Changes in Internal Controls over Financial Reporting

During the quarter ended March 31, 2015, 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 March 31, 2015, 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 March 31, 2015, 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.

PART II

ITEM 1. 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 condensed consolidated financial statements are included in Part 1 Item 1.

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. On March 12, 2015, certain claimants filed a Class Action Complaint against the Vectren Combined Plan and the Company in federal district court requesting that a class be certified and for various relief including that the Combined Plan be reformed and benefits thereunder be recalculated. The Company denied the allegations set forth in the Complaint.

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 1A. RISK FACTORS

Investors should consider carefully factors that may impact the Company’s operating results and financial condition, causing them to be materially adversely affected. The Company’s risk factors have not materially changed from the information set forth in Item 1A Risk Factors included in the Vectren 2014 Form 10-K and are therefore not presented herein.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

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 March 31, 2015.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not Applicable

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

ITEM 5. OTHER INFORMATION

Not Applicable

ITEM 6. EXHIBITS

Exhibits and Certifications

3.1	Code of By-Laws of Vectren corporation as Most Recently Amended as of March 4, 2015 (filed and designated in Form 8-K, dated March 10, 2015, File No. 1-15467, as Exhibit 3.1)
10.1	Grant Agreement for Non-Employee Director Stock Grant, dated January 1, 2015. (Filed and designated in Form 8-K, dated January 2, 2015, File No. 1-5467, as Exhibit 10.1)
10.2	Coal Supply Agreement for A.B. Brown Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., effective January 1, 2015. Contract assigned to Sunrise Coal, LLC. on August 29, 2014. (Filed in Form 10-Q herewith 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.
10.3	Coal Supply Agreement for F.B. Culley Generating Station between Southern Indiana Gas and Vectren Fuels, Inc., effective January 1, 2015. Contract assigned to Sunrise Coal, LLC. on August 29, 2014. (Filed in Form 10-Q herewith 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.
10.4	Coal Supply Agreement for Warrick 4 Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., effective January 1, 2015. Contract assigned to Sunrise Coal, LLC. on August 29, 2014. (Filed in Form 10-Q herewith as Exhibit 10.4.) Portions of the document have been omitted and filed separately pursuant to a request for confidential treatment filed with the Securities and Exchange Commission.
10.5	First Amendment to the Vectren Corporation At Risk Compensation Plan (as amended and restated May 1, 2011) (filed and designated in Form 8-K, dated February 9, 2015, File No. 1-15467, as Exhibit 99.1)
31.1	Certification Pursuant To Section 302 of The Sarbanes-Oxley Act Of 2002- Chief Executive Officer
31.2	Certification Pursuant To Section 302 of The Sarbanes-Oxley Act Of 2002- Chief Financial Officer
32	Certification Pursuant To Section 906 of The Sarbanes-Oxley Act Of 2002
101	Interactive Data File
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Linkbase

101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase

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.