

VECTREN CORP
Form 10-Q
November 03, 2016

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2016

OR

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

For the transition period from _____ to _____

Commission file number: 1-15467

VECTREN CORPORATION
(Exact name of registrant as specified in its charter)

INDIANA 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. ☒ Yes ☐ No

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

Edgar Filing: VECTREN CORP - Form 10-Q

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 ☒

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

company ☐

Accelerated filer ☐

Smaller reporting

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

☐ Yes ☒ 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	82,868,119	October 31, 2016
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:	Investor Relations Contact:
One Vectren Square	Phone Number: David E. Parker
Evansville, Indiana 47708	(812) 491-4000 Director, Investor Relations
	vvcir@vectren.com

Definitions

AFUDC: allowance for funds used during construction

ASC: Accounting Standards Codification

ASU: Accounting Standards Update

BTU / MMBTU: British thermal units / millions of BTU

DOT: Department of Transportation

EPA: Environmental Protection Agency

FAC: Fuel Adjustment Clause

FASB: Financial Accounting Standards Board

IDEM: Indiana Department of Environmental Management

IURC: Indiana Utility Regulatory Commission

kV: Kilovolt

MCF / BCF: thousands / billions of cubic feet

MDth / MMDth: thousands / millions of dekatherms

MISO: Midcontinent Independent System Operator

MW: megawatts

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

FERC: Federal Energy Regulatory Commission

OUC: Indiana Office of the Utility Consumer Counselor

GAAP: Generally Accepted Accounting Principles

PUCO: Public Utilities Commission of Ohio

GCA: Gas Cost Adjustment

XBRL: eXtensible Business Reporting Language

Table of Contents

Item Number		Page Number
	PART I. FINANCIAL INFORMATION	
1	<u>Financial Statements (Unaudited)</u>	
	Vectren Corporation and Subsidiary Companies	
	<u>Condensed Consolidated Balance Sheets</u>	<u>3</u>
	<u>Condensed Consolidated Statements of Income</u>	<u>5</u>
	<u>Condensed Consolidated Statements of Cash Flows</u>	<u>6</u>
	<u>Notes to the Condensed Consolidated Financial Statements (Unaudited)</u>	<u>7</u>
2	<u>Management's Discussion and Analysis of Financial Condition and Results of Operations</u>	<u>24</u>
3	<u>Quantitative and Qualitative Disclosures About Market Risk</u>	<u>48</u>
4	<u>Controls and Procedures</u>	<u>49</u>
	PART II. OTHER INFORMATION	
1	<u>Legal Proceedings</u>	<u>49</u>
1A	<u>Risk Factors</u>	<u>49</u>
2	<u>Unregistered Sales of Equity Securities and Use of Proceeds</u>	<u>50</u>
3	<u>Defaults Upon Senior Securities</u>	<u>50</u>
4	<u>Mine Safety Disclosures</u>	<u>50</u>
5	<u>Other Information</u>	<u>50</u>
6	<u>Exhibits</u>	<u>50</u>
	<u>Signatures</u>	<u>51</u>
2		

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	September 30, 2016	December 31, 2015
ASSETS		
Current Assets		
Cash & cash equivalents	\$ 34.4	\$ 74.7
Accounts receivable - less reserves of \$5.4 & \$5.6, respectively	227.9	227.5
Accrued unbilled revenues	94.5	142.5
Inventories	137.3	133.7
Recoverable fuel & natural gas costs	22.9	—
Prepayments & other current assets	63.2	81.0
Total current assets	580.2	659.4
Utility Plant		
Original cost	6,419.8	6,090.4
Less: accumulated depreciation & amortization	2,527.3	2,415.5
Net utility plant	3,892.5	3,674.9
Investments in unconsolidated affiliates	20.4	20.9
Other utility & corporate investments	35.7	31.2
Other nonutility investments	16.1	16.2
Nonutility plant - net	420.8	414.6
Goodwill	293.5	293.5
Regulatory assets	290.0	249.4
Other assets	42.7	39.9
TOTAL ASSETS	\$ 5,591.9	\$ 5,400.0

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

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

	September 30, 2016	December 31, 2015
LIABILITIES & SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	\$ 266.3	\$ 248.8
Refundable fuel & natural gas costs	—	7.9
Accrued liabilities	184.8	183.6
Short-term borrowings	131.2	14.5
Current maturities of long-term debt	—	73.0
Total current liabilities	582.3	527.8
Long-term Debt - Net of Current Maturities	1,713.8	1,712.9
Deferred Credits & Other Liabilities		
Deferred income taxes	874.8	805.4
Regulatory liabilities	450.9	433.9
Deferred credits & other liabilities	239.0	236.2
Total deferred credits & other liabilities	1,564.7	1,475.5
Commitments & Contingencies (Notes 7-11)		
Common Shareholders' Equity		
Common stock (no par value) – issued & outstanding	727.5	722.8
82.9 & 82.8, respectively		
Retained earnings	1,004.8	962.2
Accumulated other comprehensive (loss)	(1.2) (1.2
Total common shareholders' equity	1,731.1	1,683.8
TOTAL LIABILITIES & SHAREHOLDERS' EQUITY	\$ 5,591.9	\$ 5,400.0

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

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

	Three Months Ended September 30, 2016		Nine Months Ended September 30, 2016	
	2015		2015	
OPERATING REVENUES				
Gas utility	\$117.7	\$108.5	\$530.8	\$590.1
Electric utility	173.5	164.4	463.3	466.0
Nonutility	339.8	300.6	755.3	774.6
Total operating revenues	631.0	573.5	1,749.4	1,830.7
OPERATING EXPENSES				
Cost of gas sold	29.1	27.3	174.6	235.8
Cost of fuel & purchased power	50.9	47.9	140.3	144.9
Cost of nonutility revenues	110.5	106.8	248.7	264.5
Other operating	256.3	234.3	686.9	690.5
Depreciation & amortization	65.4	65.0	193.4	191.6
Taxes other than income taxes	13.3	12.3	44.8	44.6
Total operating expenses	525.5	493.6	1,488.7	1,571.9
OPERATING INCOME	105.5	79.9	260.7	258.8
OTHER INCOME				
Equity in (losses) of unconsolidated affiliates	(0.1)	(0.6)	(0.2)	(0.6)
Other income – net	7.6	4.0	22.0	14.7
Total other income	7.5	3.4	21.8	14.1
INTEREST EXPENSE	20.9	21.2	64.3	63.1
INCOME BEFORE INCOME TAXES	92.1	62.1	218.2	209.8
INCOME TAXES	30.7	22.8	76.2	77.7
NET INCOME AND COMPREHENSIVE INCOME	\$61.4	\$39.3	\$142.0	\$132.1
WEIGHTED AVERAGE AND DILUTED COMMON SHARES OUTSTANDING	82.8	82.7	82.8	82.7
BASIC AND DILUTED EARNINGS PER SHARE OF COMMON STOCK	\$0.74	\$0.48	\$1.71	\$1.60
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	\$0.40	\$0.38	\$1.20	\$1.14

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)

	Nine Months Ended September 30, 2016 2015	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	\$142.0	\$132.1
Adjustments to reconcile net income to cash from operating activities:		
Depreciation & amortization	193.4	191.6
Deferred income taxes & investment tax credits	68.9	44.6
Equity in losses of unconsolidated affiliates	0.2	0.6
Provision for uncollectible accounts	5.3	5.9
Expense portion of pension & postretirement benefit cost	2.9	4.7
Other non-cash items - net	2.0	6.3
Changes in working capital accounts:		
Accounts receivable & accrued unbilled revenues	42.3	17.8
Inventories	(3.6)	(11.8)
Recoverable/refundable fuel & natural gas costs	(30.8)	27.1
Prepayments & other current assets	15.0	46.9
Accounts payable, including to affiliated companies	(7.9)	(36.5)
Accrued liabilities	1.2	(1.9)
Unconsolidated affiliate dividends	0.2	0.8
Employer contributions to pension & postretirement plans	(18.6)	(23.3)
Changes in noncurrent assets	(32.0)	(15.8)
Changes in noncurrent liabilities	(2.2)	(2.5)
Net cash provided by operating activities	378.3	386.6
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from:		
Long-term debt, net of issuance costs	—	37.5
Dividend reinvestment plan & other common stock issuances	4.6	4.7
Requirements for:		
Dividends on common stock	(99.4)	(94.3)
Retirement of long-term debt	(73.0)	(5.0)
Net change in short-term borrowings	116.7	(45.4)
Net cash used in financing activities	(51.1)	(102.5)
CASH FLOWS FROM INVESTING ACTIVITIES		
Proceeds from sale of assets and other collections	16.6	7.4
Requirements for:		
Capital expenditures, excluding AFUDC equity	(381.9)	(349.4)
Business acquisitions and other costs	(4.7)	(14.0)
Changes in restricted cash	2.5	(9.7)
Net cash used in investing activities	(367.5)	(365.7)
Net change in cash & cash equivalents	(40.3)	(81.6)
Cash & cash equivalents at beginning of period	74.7	86.4
Cash & cash equivalents at end of period	\$34.4	\$4.8
The accompanying notes are an integral part of these condensed consolidated financial statements.		

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 or Vectren Energy Delivery of Indiana - North), Southern Indiana Gas and Electric Company (SIGECO or Vectren Energy Delivery of Indiana - South), and Vectren Energy Delivery of Ohio, Inc. (VEDO). Utility Holdings also has other assets that provide information technology and other services to the three utilities. Utility Holdings' consolidated operations are collectively referred to as the Utility Group. Both Vectren and Utility Holdings are holding companies as defined by the Energy Policy Act of 2005. Vectren was incorporated under the laws of Indiana on June 10, 1999.

Indiana Gas provides energy delivery services to approximately 586,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 144,000 electric customers and approximately 111,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to approximately 316,000 natural gas customers located near Dayton in west central Ohio.

The Company, through Vectren Enterprises, Inc. (Enterprises), is involved in nonutility activities in two primary business areas: Infrastructure Services and Energy Services. Infrastructure Services provides underground pipeline construction and repair services. Energy Services provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects. Enterprises also has other legacy businesses that have investments in energy-related opportunities and services and other investments. All of the above are collectively referred to as the Nonutility Group. Enterprises supports the Company's regulated utilities by providing infrastructure services.

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 interim 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, 2015, filed with the Securities and Exchange Commission on February 23, 2016, 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 September 30, 2016		Nine Months Ended September 30, 2015	
(In millions, except per share data)				
Numerator:				
Reported net income (Numerator for Basic and Diluted EPS)	\$ 61.4	\$ 39.3	\$ 142.0	\$ 132.1
Denominator:				
Weighted average common shares outstanding (Denominator for Basic and Diluted EPS)	82.8	82.7	82.8	82.7
Basic and Diluted EPS	\$ 0.74	\$ 0.48	\$ 1.71	\$ 1.60

As of September 30, 2016, the Company no longer has any stock options outstanding. For the three months ended September 30, 2015 there were no stock options outstanding, and for the nine months ended September 30, 2015, all stock options were dilutive and immaterial. For the three and nine months ended September 30, 2016 and 2015, all 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 \$5.3 million and \$5.0 million in the three months ended September 30, 2016 and 2015, respectively, as a component of operating revenues. During the nine months ended September 30, 2016 and 2015, these taxes totaled \$20.2 million and \$22.1 million, respectively. 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 closed qualified defined benefit pension plans, a nonqualified supplemental executive retirement plan (SERP), and a postretirement benefit plan. The defined benefit pension plans and postretirement benefit plan, which cover eligible full-time regular employees, are primarily noncontributory. The postretirement health care and life insurance plans are a combination of self-insured and fully insured plans. The qualified pension plans and the SERP plan are aggregated under the heading "Pension Benefits." The postretirement benefit plan is presented under the heading "Other Benefits."

Net Periodic Benefit Costs

A summary of the components of net periodic benefit cost 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			
	September 30,			
	Pension Benefits		Other Benefits	
(In millions)	2016	2015	2016	2015
Service cost	\$1.8	\$1.9	\$0.1	\$0.1
Interest cost	3.6	3.7	0.4	0.5
Expected return on plan assets	(5.7)	(5.6)	—	—
Amortization of prior service cost	0.1	0.2	(0.7)	(0.7)
Amortization of actuarial loss	1.8	2.1	—	0.2
Net periodic cost (benefit)	\$1.6	\$2.3	\$(0.2)	\$0.1

	Nine Months Ended			
	September 30,			
	Pension Benefits		Other Benefits	
(In millions)	2016	2015	2016	2015
Service cost	\$5.3	\$5.9	\$0.2	\$0.3
Interest cost	10.9	11.0	1.3	1.5
Expected return on plan assets	(17.1)	(16.9)	—	—
Amortization of prior service cost	0.3	0.6	(2.2)	(2.2)
Amortization of actuarial loss	5.4	6.3	—	0.5
Net periodic cost (benefit)	\$4.8	\$6.9	\$(0.7)	\$0.1

Employer Contributions to Qualified Pension Plans

In 2016, the Company has made \$15 million in contributions to its qualified pension plans.

6. Supplemental Cash Flow Information

As of September 30, 2016 and December 31, 2015, the Company has accruals related to utility and nonutility plant purchases totaling approximately \$43.3 million and \$19.4 million, respectively.

7. Investment in ProLiance Holdings, LLC

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

The Company's investment at September 30, 2016, shown at its 61 percent ownership share of the individual net assets of ProLiance, is as follows.

	As of
	September
	30,
(In millions)	2016
Cash	\$ 1.7
Investment in LA Storage	22.4
Other midstream asset investment	5.2
Total investment in ProLiance	\$ 29.3
Included in:	
Investments in unconsolidated affiliates	\$ 19.2
Other nonutility investments	\$ 10.1

LA Storage

ProLiance Transportation and Storage, LLC (PT&S), a subsidiary of ProLiance, and Sempra Energy International (SEI), a subsidiary of Sempra Energy (SE), through a joint venture, have a 100 percent interest in a development project for salt-cavern natural gas storage facilities known as LA Storage. PT&S is the minority member with an approximate 25 percent interest, which it accounts for using the equity method. The project, which includes a pipeline system, is expected to include 12-19 Bcf of storage capacity, and has the potential for further expansion. This pipeline system is currently connected with several interstate pipelines, including the Cameron Interstate Pipeline operated by Sempra Pipelines & Storage, and 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 and pipeline system is dependent on market conditions, including pricing, need for storage and transmission capacity, and development of the liquefied natural gas market, among other factors. To date, development activity has been modest due to the current low demand for storage facilities. The development of the storage market and related pricing are critical assumptions in the analysis of the recoverability of the investment's carrying value. As of September 30, 2016 and December 31, 2015, ProLiance's investment in the joint venture was \$36.8 million and \$36.4 million, respectively.

8. Commitments & Contingencies

Performance Guarantees & Product Warranties

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

Specific to ESG's role as a general contractor in the performance contracting industry, at September 30, 2016, there are 47 open surety bonds supporting future performance. The average face amount of these obligations is \$9.4 million, and the largest obligation has a face amount of \$51.0 million. The maximum exposure from these obligations is limited to the level of uncompleted work and further limited by bonds issued to ESG by various subcontractors. At September 30, 2016, approximately 37 percent of work was yet to be completed on projects with open surety bonds. A significant portion of these open surety bonds will be released within one year. In instances where ESG operates

facilities, project guarantees extend over a longer period. In addition to its performance obligations, ESG also warrants the functionality of certain installed infrastructure generally for one year and the associated energy savings over a specified number of years.

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

Corporate Guarantees

The Company issues parent level guarantees to certain vendors and customers of its wholly owned subsidiaries. These guarantees do not represent incremental consolidated obligations; but rather, represent guarantees of subsidiary obligations in order to allow those subsidiaries the flexibility to conduct business without posting other forms of collateral. At September 30, 2016, parent level guarantees support a maximum of \$258 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. Under this agreement, all payment obligations to Keenan 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 has other guarantees outstanding, including letters of credit, supporting other consolidated subsidiary operations.

While there can be no assurance that the Company guarantee provisions will not be called upon, historically no such provisions have been called upon, and further, 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, some of which are five and ten year agreements 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 condition, results of operations or cash flows.

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

In April 2011, Indiana Senate Bill 251 (Senate Bill 251) was signed into Indiana law. The law provides a framework to recover 80 percent of federally mandated costs through a periodic rate adjustment mechanism outside of a general rate case. Such costs include a return on the federally mandated capital investment, based on the overall rate of return most recently approved by the IURC, along with recovery of depreciation and other operating costs associated with these mandates. The remaining 20 percent of those costs is deferred for future recovery in the utility's next general rate case.

In April 2013, Indiana Senate Bill 560 (Senate Bill 560) was signed into Indiana law. This legislation supplements Senate Bill 251 described above, and provides for cost recovery outside of a base rate proceeding for projects that either improve electric and gas system reliability and safety or are economic development projects that provide rural areas with access to gas service. Provisions of the legislation require that, among other things, requests for recovery include a seven-year project plan. Once the plan is approved by the IURC, 80 percent of such costs are eligible for current recovery using a periodic rate adjustment

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

In June 2011, Ohio House Bill 95 (House Bill 95) was signed into law. Outside of a base rate proceeding, this legislation permits a natural gas utility to apply for recovery of much of its capital expenditure program. This legislation also allows for the deferral of costs, such as depreciation, property taxes, and debt-related post-in-service carrying costs until recovery is approved by the PUCO.

Indiana Recovery and Deferral Mechanisms

The Company's Indiana natural gas utilities received Orders in 2008 and 2007 associated with the most recent base rate cases. These Orders authorized the deferral of financial impacts associated with bare steel and cast iron replacement activities. The Orders provide for the deferral of depreciation and post-in-service carrying costs on qualifying projects totaling \$20 million annually at Indiana Gas and \$3 million annually at SIGECO. The debt-related post-in-service carrying costs are currently recognized in the Condensed Consolidated Statements of Income. The recording of post-in-service carrying costs and depreciation deferral is limited by individual qualifying project to three years after being placed into service at SIGECO and four years after being placed into service at Indiana Gas. At September 30, 2016 and December 31, 2015, the Company has regulatory assets totaling \$21.7 million and \$19.9 million, respectively, associated with the deferral of depreciation and debt-related post-in-service carrying cost activities. Beginning in 2014, all bare steel and cast iron replacement activities are now part of the Company's seven-year capital investment plan discussed below.

Requests for Recovery under Indiana Regulatory Mechanisms

On August 27, 2014, the IURC issued an Order (August 2014 Order) approving the Company's seven-year capital infrastructure replacement and improvement plan (the Plan), beginning in 2014, and the proposed accounting authority and recovery. Compliance projects and other infrastructure improvement projects were approved pursuant to Senate Bill 251 and 560, respectively. As provided in the two laws, the Order approved semi-annual filings for rate recovery of 100 percent of the costs, inclusive of return, related to these capital investments and operating expenses, with 80 percent of the costs, including a return, recovered currently via an approved tracking mechanism and 20 percent of the costs deferred and recovered in the Company's next base rate proceeding. In addition, the Order established guidelines to annually update the seven-year capital investment plan. Finally, the Order approved the Company's proposal to recover eligible costs via a fixed monthly charge per residential customer.

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

2016 Order on April 29, 2016 to challenge the IURC's finding which limits the scope of the Plan updates. The outcome of the appeal is expected in 2017.

On June 29, 2016, the IURC issued an Order (June 2016 Order) approving the inclusion in rates of investments made from July 2015 to December 2015. Through the June 2016 Order, approximately \$262 million of the approved capital investment plan has been spent and included for recovery as of December 31, 2015.

In October 2016, the Company submitted its fifth semi-annual filing, seeking approval of the recovery of investments made through June 30, 2016, as well as updates to the approved seven-year capital investment plan. The updated plan reflects total capital expenditures of approximately \$950 million for 2014 through 2020, an increase of \$60 million from the previous plan approved in March 2016. This increase is primarily due to additional costs related to pipeline safety and compliance requirements under Senate Bill 251. The Company expects an order in this proceeding in early 2017.

At September 30, 2016 and December 31, 2015, the Company has regulatory assets related to the Plan totaling \$42.4 million and \$28.6 million, respectively, associated with the return on investment as well as the deferral of depreciation and other operating expenses.

Ohio Recovery and Deferral Mechanisms

The PUCO Order approving the Company's 2009 base rate case in the Ohio service territory authorized a distribution replacement rider (DRR). The DRR's primary purpose is recovery of investments in utility plant and related operating expenses associated with replacing bare steel and cast iron pipelines, as well as certain other infrastructure investments. This rider is updated annually for qualifying capital expenditures and allows for a return on those capital expenditures based on the rate of return approved in the 2009 base rate case. In addition, deferral of depreciation and the ability to accrue debt-related post-in-service carrying costs is also allowed until the related capital expenditures are included in the DRR. The Order also initially established a prospective bill impact evaluation on the annual deferrals. 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 certain other infrastructure investments. The Order limits the resulting DRR fixed charge per month for residential and small general service customers to specific graduated levels over the next five years. The capital expenditure plan is subject to the graduated caps on the fixed DRR monthly charge applicable to residential and small general service customers approved in the Order. In the event the Company exceeds these caps, amounts in excess can be deferred for future recovery; however, the remaining capital expenditure plan to be included for recovery in future DRR filings, estimated to be approximately \$100 million to \$120 million for 2016 and 2017, is not expected to exceed those caps. The Order also approved the Company's commitment that the DRR can only be further extended as part of a base rate case. In total, the Company has made capital investments on projects that are now in-service under the DRR totaling \$232 million as of September 30, 2016, of which \$204 million has been approved for recovery in the DRR through December 31, 2015. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were \$22.9 million and \$18.2 million at September 30, 2016 and December 31, 2015, respectively. In August 2016, the Company received approval to adjust the DRR rates, effective September 1, 2016, for recovery of costs incurred through December 31, 2015.

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 not file a general rate case for the inclusion in rate base of the above costs until the expiration of the DRR.

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 September 30, 2016, the Company's deferrals have not reached this bill impact cap. On May 2, 2016, the Company submitted its most recent annual report required under its House Bill 95 Order. This report covers the Company's capital expenditure program through calendar year 2016.

Pipeline and Hazardous Materials Safety Administration (PHMSA)

On March 18, PHMSA published a notice of proposed rulemaking (NPRM) on the safety of gas transmission and gathering lines. The proposed rule addresses many of the remaining requirements of the 2011 Pipeline Safety Act, with a particular focus on extending integrity management rules to address a much larger portion of the natural gas infrastructure and adds requirements to address broader threats to the integrity of a pipeline system. The Company is evaluating the impact that these proposed rules will have on its integrity management programs and transmission and distribution systems. Further, the

Company is reviewing the Underground Natural Gas Storage Safety Recommendations from a joint Department of Energy and PHMSA led interagency task force. PHMSA has final rules pending that address requirements related to plastic pipe, operator qualifications, valve installation and rupture detection, and underground storage integrity management. Each of these rules is expected to be published by PHMSA in 2017. Additionally, PHMSA has recently finalized a rule on excess flow valves, which will go into effect in 2017. These rules will increase the potential for capital expenditures and increase operating and maintenance expenses. The Company believes that the cost to comply with these new rules would be considered federally mandated costs and therefore should be recoverable using the regulatory recovery mechanisms referenced above.

10. Electric Rate & Regulatory Matters

SIGECO Electric Environmental Compliance Filing

On January 28, 2015, the IURC issued an Order (January Order) approving the Company's request for approval of capital investments in its coal-fired generation units to comply with new EPA mandates related to mercury and air toxic standards (MATS) effective in 2015 and to address an outstanding Notice of Violation (NOV) related to sulfur trioxide emissions from the EPA. As of September 30, 2016, approximately \$30 million has been spent on equipment to control mercury in both air and water emissions, and \$40 million to address the issues raised in the NOV. The total investment is estimated to be between \$70 million and \$75 million. The Order approved the Company's request for deferred accounting treatment, as supported by provisions under Indiana Senate Bill 29 (Senate Bill 29) and Senate Bill 251. The accounting treatment includes the deferral of depreciation and property tax expense related to these investments, accrual of post-in-service carrying costs, and deferral of incremental operating expenses related to compliance with these standards. The initial phase of the projects went into service in 2014, with the remaining investment occurring in 2015 and 2016. As of September 30, 2016, the Company has approximately \$5.8 million deferred related to depreciation, property tax, and operating expense, and \$2.3 million deferred related to post-in-service carrying costs.

In June 2015, Joint Appellants' Citizens Action Coalition of Indiana, Inc., Sierra Club, Inc., and Valley Watch, Inc. (the appellants) challenged the IURC's January Order. On October 29, 2015, the Indiana Court of Appeals issued an opinion that affirmed the IURC's findings with regard to equipment required to comply with MATS and certain national pollutant discharge elimination system rules (approximately \$35 million) but remanded the case to the IURC to determine whether a certificate of public convenience and necessity (CPCN) should be issued for the equipment required by the NOV (approximately \$40 million). On June 22, 2016, the IURC issued an Order granting Vectren a CPCN for the NOV-required equipment. On July 21, 2016, the appellants initiated an appeal of the IURC's June 22, 2016 Order challenging the findings made by the IURC. The Company believes the IURC decision is well founded and will ultimately be upheld. The outcome of the appeal is expected in 2017.

SIGECO Electric Demand Side Management (DSM) Program Filing

On August 31, 2011, the IURC issued an Order approving an initial three-year DSM plan in the SIGECO electric service territory that complied with the IURC's energy saving targets. Consistent with the Company's proposal, the Order approved, among other items, the following: 1) recovery of costs associated with implementing the DSM Plan; 2) the recovery of a performance incentive mechanism based on measured savings related to certain DSM programs; and 3) lost margin recovery associated with the implementation of DSM programs for large customers. On June 20, 2012, the IURC issued an Order approving a small customer lost margin recovery mechanism, inclusive of all previous deferrals. For the nine months ended September 30, 2016 and 2015, the Company recognized electric utility revenue of \$8.2 million and \$7.5 million, respectively, associated with this approved lost margin recovery mechanism.

On March 28, 2014, Indiana Senate Bill 340 was signed into law. This legislation ended electric DSM programs on December 31, 2014 that had been conducted to meet the energy savings requirements established by the IURC in

2009. The legislation also allows for industrial customers to opt out of participating in energy efficiency programs. As of January 1, 2016, approximately 80 percent of the Company's eligible industrial load has opted out of participation in the applicable energy efficiency programs. The Company filed a request for IURC approval of a new portfolio of DSM programs on May 29, 2014 to be offered in 2015. On October 15, 2014, the IURC issued an Order approving a Settlement between the OUCC and the Company regarding the new portfolio of DSM programs effective January 2015, and new programs for 2015 were implemented during the first quarter of 2015.

On May 6, 2015, Indiana's governor signed Indiana Senate Bill 412 (Senate Bill 412) into law requiring electricity suppliers to submit energy efficiency plans to the IURC at least once every three years. Senate Bill 412 also permits the recovery of all program costs, including lost revenues and financial incentives associated with those plans and approved by the IURC. The Company made its first filing pursuant to this bill in June 2015, which proposed energy efficiency programs for calendar years 2016 and 2017. In September 2015, the Company received an Order to continue offering and recovering the associated cost of its 2015 programs until March 31, 2016. In October 2015, the OUCC and Citizens Action Coalition of Indiana filed testimony recommending the rejection of the Company's plan, contending it was not reasonable under the terms of Senate Bill 412 due to the program design and the Company's proposal to recover lost revenues and incentives associated with the measures. Vectren filed rebuttal testimony in October 2015 defending the plan's compliance with Senate Bill 412.

On March 23, 2016, the IURC issued an Order approving the Company's 2016-2017 energy efficiency programs. The Order provides for cost recovery of program and administrative expenses and includes performance incentives for reaching energy savings goals. The Order also included a lost margin recovery mechanism that now limits that recovery related to new programs to the shorter of four years or the life of the installed energy efficiency measure. Prior electric energy efficiency orders did not limit lost margin recovery in this manner. This ruling follows three other recent IURC decisions implementing the same lost margin recovery limitation with respect to other electric utilities in Indiana. The Company is committed to continuing to promote and drive participation in its 2016-2017 energy efficiency programs and beyond and has therefore appealed this lost margin recovery restriction.

FERC Return on Equity (ROE) Complaints

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

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

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

The Company has reflected these results in its financial statements. As of September 30, 2016, the Company had invested approximately \$157.7 million in qualifying projects. The net plant balance for these projects totaled \$137.7 million at September 30, 2016.

11. Environmental Matters

The Company's utility operations and properties are subject to extensive environmental regulation pursuant to a variety of federal, state, and municipal laws and regulations. These environmental regulations impose, among other things, restrictions, liabilities, and obligations in connection with the storage, transportation, treatment, and disposal of hazardous substances and limit airborne emissions from electric generating facilities including particulate matter, sulfur dioxide (SO₂), nitrogen oxide (NO_x), and mercury, among others. Environmental legislation and regulation also requires that facilities, sites, and other

properties associated with the Company's operations be operated, maintained, abandoned, and reclaimed to the satisfaction of applicable regulatory authorities. The Company's current costs to comply with these laws and regulations are significant to its results of operations and financial condition.

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

Air Quality

Mercury and Air Toxics (MATS) Rule

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

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

Notice of Violation for A.B. Brown Power Plant

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

As noted previously, on January 28, 2015, the IURC issued an Order approving the Company's request for approval of capital investments on its coal-fired generation units to comply with new EPA mandates related to MATS effective in 2015 and to address the outstanding NOV. The total investment is estimated to be between \$70 million and \$75 million, roughly half of which has been spent to control mercury in both air and water emissions, and the remaining investment has been made to address the issues raised in the NOV.

In June 2015, Joint Appellants' Citizens Action Coalition of Indiana, Inc., Sierra Club, Inc., and Valley Watch, Inc. (the appellants) challenged the IURC's January Order. On October 29, 2015, the Indiana Court of Appeals issued an opinion that affirmed the IURC's findings with regard to equipment required to comply with MATS and certain national pollutant discharge elimination system rules (approximately \$35 million) but remanded the case to the IURC to determine whether a certificate of public convenience and necessity (CPCN) should be issued for the equipment required by the NOV (approximately \$40 million). On June 22, 2016, the IURC issued an Order granting Vectren a CPCN for the NOV-required equipment. On July 21, 2016, the appellants initiated an appeal of the IURC's June 22,

2016 Order challenging the findings made by the IURC. The Company believes the IURC decision is well founded and will ultimately be upheld. The outcome of the appeal is expected in 2017.

Ozone NAAQS

On November 26, 2014, the EPA proposed to tighten the current National Ambient Air Quality Standard (NAAQS) for ozone from the current standard of 75 parts per billion (ppb) to a level with the range of 65 to 70 ppb. On October 1, 2015, the EPA finalized a new NAAQS for ozone at the high end of the range, or 70 ppb. The EPA is expected to make final determinations as to whether a region is in attainment for the new NAAQS in 2018 based upon monitoring data from 2014-2016. While it is possible that counties in southwest Indiana could be declared in non-attainment with the new standard, and thus could have an effect on future economic development activities in the Company's service territory, the Company does not anticipate any significant compliance cost impacts from the determination given its previous investment in SCR technology for NOx control on its units. In December of 2015, the EPA proposed a supplement to the current Cross State Air Pollution Rule (CSAPR) that would require further NOx reductions during the ozone season (May - September), which was finalized in September. The Company is positioned to comply with these NOx reduction requirements through its current investment in SCR technology.

One Hour SO2 NAAQS

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

Coal Ash Waste Disposal, Ash Ponds and Water

Coal Combustion Residuals Rule

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

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

At September 30, 2015, the Company recorded an approximate \$25 million asset retirement obligation (ARO) and that amount is unchanged at September 30, 2016. The recorded ARO reflected the present value of the approximate \$35 million in estimated costs in the range above. These assumptions and estimations are subject to change in the future and could materially impact the amount of the estimated ARO.

In order to maintain current operations of the ponds, the Company has spent approximately \$12 million on the reinforcement

of the ash pond dams and other operational changes in 2016 to meet the more stringent 2,500 year seismic event structural and safety standard in the CCR rule.

Effluent Limitation Guidelines (ELGs)

Under the Clean Water Act, the EPA sets technology-based guidelines for water discharges from new and existing facilities. On September 30, 2015, the EPA released final revisions to the existing steam electric ELGs setting stringent technology-based water discharge limits for the electric power industry. The EPA focused this rulemaking on wastewater generated primarily by pollution control equipment necessitated by the comprehensive air regulations, specifically setting strict water discharge limits for arsenic, mercury and selenium for scrubber waste waters. The ELGs will be implemented when existing water discharge permits for the plants are renewed, with compliance activities expected to commence where operations continue, within the 2018-2023 time frame. The current wastewater discharge permit for the Brown power plant was up for renewal in October and the permit for the Culley plant, is up for renewal in December 2016. During the renewal process, existing permits remain in place. The Company is working with Indiana regulators on permit renewals which will include a compliance schedule for ELGs. In no event will compliance with the ELGs be required prior to November 2018. The ELGs work in tandem with the aforementioned CCR requirements, effectively prohibiting the use of less costly lined sediment basin options for disposal of coal combustion residuals, and virtually mandate conversions to dry bottom ash handling.

Cooling Water Intake Structures

Section 316(b) of the Clean Water Act requires that generating facilities use the “best technology available” (BTA) to minimize adverse environmental impacts on a body of water. More specifically, Section 316(b) is concerned with impingement and entrainment of aquatic species in once-through cooling water intake structures used at electric generating facilities. A final rule was issued by the EPA on May 19, 2014. The final rule does not mandate cooling water tower retrofits but requires a state level case-by-case assessment of BTA for each facility. The final rule lists seven presumptive technologies which would qualify as BTA. These technologies range from intake screen modifications to cooling water tower retrofits. Ecological and technology assessment studies must be completed prior to determining BTA for the Company’s facilities. The Company is currently undertaking the required ecological studies and anticipates timely compliance in 2020-2021. To comply, the Company believes that capital investments will likely be in the range of \$4 million to \$8 million.

Climate Change

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

In the event that a state does not submit a SIP, the EPA also released a proposed federal implementation plan (FIP), which would be imposed on those states without an approved SIP. The proposed FIP would apply an emission rate requirement directly on generating units. Under the proposed FIP, the CO₂ emission rate limit for coal-fired units would start at 1,671 lbs CO₂/MWh in 2022 and decrease to a final emission rate cap of 1,305 lbs CO₂/MWh by 2030. While the FIP emission rate cap appears to be slightly less stringent than the state reduction goal for Indiana, the cap would apply directly to generating units and these units would not have the benefit of averaging emission rates with rates from zero-carbon sources as would be available in a SIP. Purchases of emission credits from zero-carbon sources can be made for compliance. The FIP will

be subject to extensive public comments prior to finalization. Whether Indiana will file a SIP has yet to be determined. Pending that determination, the electric utilities in Indiana will continue to encourage the state's designated agency to analyze various compliance options and the possible integration into a state plan submittal.

At the time of release of the CPP, Indiana was the 5th largest carbon emitter in the nation in tons of CO₂ produced from electric generation. The Company's share of total tons of CO₂ generated by Indiana's electric utilities has historically been less than 6 percent. Since 2005 through 2015, the Company has achieved a reduction in emissions of CO₂ of 31 percent (on a tonnage basis) through the retirement of F.B. Culley Unit 1, expiration of municipal contracts, electric conservation, the addition of renewable generation, and the installation of more efficient dense pack turbine technology. Since emissions are further impacted by coal burn reductions and energy efficiency programs, the Company's emissions of CO₂ can vary year to year. With respect to renewable generation, in 2008 and 2009, the Company executed long-term purchase power commitments for a total of 80 MW of wind energy. The Company currently has approximately 4 percent of its electricity being provided by energy sources other than coal and natural gas, due to the long-term wind contracts and landfill gas investment. With respect to CO₂ emission rate, since 2005 through 2015, the Company has lowered its CO₂ emission rate (as measured in lbs CO₂/MWh) from 1,967 lbs CO₂/MWh to 1,922 lbs CO₂/MWh, for a reduction of 3 percent. The Company's CO₂ emission rate of 1,922 lbs CO₂/MWh is basically the same as Indiana's average CO₂ emission rate of 1,923 lbs CO₂/MWh. The Company plans to consider these reductions in CO₂ emissions and renewable generation in future discussions with the state to develop a possible state implementation plan.

Impact of Legislative Actions & Other Initiatives is Unknown

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

In addition to the federal programs, the United States and 194 other countries agreed by consensus to limit GHG emissions beginning after 2020 in the 2015 United Nations Framework Convention on Climate Change Paris Agreement. The United States has proposed a 26-28 percent GHG emission reduction from 2005 levels by 2025. As previously noted, since 2005 through 2015, the Company has achieved reduced emissions of CO₂ by 31 percent (on a tonnage basis). While the legislative outcome of the CPP rules remains uncertain, the Company will continue to monitor regulatory activity regarding GHG emission standards that may affect its electric generating units.

Integrated Resource Planning Process

As required by the state of Indiana, the Company is currently in the process of completing its 2016 Integrated Resource Plan (IRP). The state requires each electric utility to perform and submit an IRP that uses economic modeling to consider the costs and risks associated with available resource options to provide reliable electric service for the next twenty year period. During 2016, the Company has held two of three public stakeholder meetings to gather input and feedback as well as communicate results of the IRP process as it progresses. A final IRP report is expected to be submitted to the IURC for review in December 2016. While the IURC reviews these reports, it does not formally approve or reject the plans. In developing its IRP, the Company will consider both the cost to continue operating its existing generation units in a manner that complies with current and anticipated future environmental requirements, as well as various resource alternatives, such as the use of energy efficiency programs and renewable resources as part of its overall generation portfolio. Due to the Company continuing to study compliance requirements

and since the IRP will be used to drive future resource decisions, the Company cannot reasonably estimate the total cost it will incur to comply with the CCR, ELG, and CPP regulations.

Further, the 2016 IRP will also evaluate the ongoing operation of the 300 MW unit at the Warrick Power Plant (Warrick Unit 4) that SIGECO and Alcoa Generating Corporation (AGC), a subsidiary of Alcoa, Inc. (Alcoa), own as tenants in common.

SIGECO's proportionate cost of the unit is included in rate base. In the first quarter of 2016, Alcoa closed its smelter

operations. Historically, on-site generation owned and operated by AGC has been used to provide power to the smelter, as well as other mill operations, which will continue. Generation from Alcoa's share of Warrick Unit 4 has historically been sold into the MISO market. Alcoa's operational changes, as described above, lead to a number of uncertainties including its plans regarding the future ownership and operation of Warrick Unit 4 as well as potential environmental regulation implications under the CCR and ELG regulations. The Company is actively working with Alcoa on plans related to continued operation of Warrick Unit 4 and what operating scenarios to consider in the IRP.

The 2016 IRP will produce a variety of resource options to be considered, including a preferred resource plan. Based on the resulting analysis, the Company will develop an overall strategy that may include compliance projects on some units, possible replacement of other units, and the opportunity for the use of renewable sources. While the cost of compliance with CCR, ELG, and CPP could be significant, the Company anticipates compliance costs associated with ELG and CCR will likely be the most significant. The Company believes that all compliance costs would be considered a federally mandated cost of providing electricity, and therefore if incurred, should be recoverable either from customers through Senate Bill 251 as referenced above, Senate Bill 29, which was used by the Company to recover its initial pollution control investments or through other forms of rate recovery.

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 approximately \$14.8 million of the expected \$15.8 million in insurance recoveries.

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company's utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of September 30, 2016 and December 31, 2015, approximately \$2.5 million and \$3.3 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana

Gas and SIGECO sites.

20

12. 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. The amendments in this guidance state that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This new guidance requires improved disclosures to help users of financial statements better understand the nature, amount, timing, and uncertainty of revenue that is recognized.

On July 9, 2015, the FASB approved a one year deferral that became effective through an ASU in August and changed the effective date to annual reporting periods beginning after December 15, 2017, including interim periods, with early adoption permitted, but not before the original effective date of December 15, 2016. The Company is currently evaluating the standard to determine application date, transition method, and impact the standard will have on the financial statements.

Simplifying the Presentation of Debt Issuance Costs

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

Leases

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

Stock Compensation

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

Other Recently Issued Standards

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

13. Fair Value Measurements

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

(In millions)	September 30, 2016		December 31, 2015	
	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	\$1,713.8	\$1,910.0	\$1,785.9	\$1,899.6
Short-term borrowings	131.2	131.2	14.5	14.5
Cash & cash equivalents	34.4	34.4	74.7	74.7
Restricted cash	3.3	3.3	5.9	5.9

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. 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 September 30, 2016 and December 31, 2015, the fair value for these financial instruments was not estimated. The carrying value of these investments at September 30, 2016 and December 31, 2015 was approximately \$16.1 million, and is included in Other nonutility investments.

The Company has reclassified its debt issuance costs, in accordance with ASU 2015-03, Simplifying the Presentation of Debt Issuance Costs. The adoption of the accounting standard update changes the presentation of debt issuance costs in financial statements by requiring 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. The guidance was adopted as of January 1, 2016, and has been applied retrospectively to all periods presented. The effect of the change on the December 31, 2015 balance sheet was the reclassification of \$8.6 million from Regulatory assets to Long-term Debt and the reclassification of \$1.3 million from Other assets to Long-term Debt. The adoption of the standard had no material impact on the Company's financial condition, results of operations, or cash flows.

14. 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 about twenty percent of Ohio, primarily in the west-central area. 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. These regulated operations supply natural gas and/or electricity

to over one million customers. In total, the Utility Group reports three operating segments: Gas Utility Services, Electric Utility Services, and Other operations.

The Nonutility Group reports the following segments: Energy Services, Infrastructure Services, and Other Businesses. Energy Services provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects. The Infrastructure Services segment, through wholly owned subsidiaries Miller Pipeline, LLC and Minnesota Limited, LLC, provides underground pipeline construction and repair services for customers that include Vectren Utility Holdings' utilities. Fees incurred by Vectren Utility Holdings and its subsidiaries for these pipeline construction and repair services totaled \$36.3 million and \$36.6 million for the three months ended September 30, 2016 and 2015, respectively, and for the nine months ended September 30, 2016 and 2015 totaled \$93.1 million and \$85.9 million, respectively.

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

Corporate and Other includes unallocated corporate expenses such as advertising and certain charitable contributions, among other activities, that benefit the Company's 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		Nine Months	
	Ended		Ended	
(In millions)	September 30,	September 30,	September 30,	September 30,
	2016	2015	2016	2015
Revenues				
Utility Group				
Gas Utility Services	\$117.7	\$108.5	\$530.8	\$590.1
Electric Utility Services	173.5	164.4	463.3	466.0
Other Operations	10.5	10.2	31.6	30.5
Eliminations	(10.4)	(10.1)	(31.4)	(30.3)
Total Utility Group	291.3			