VECTREN UTILITY HOLDINGS INC
Form 10-Q
November 10, 2016

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 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: 1-16739

VECTREN UTILITY HOLDINGS, INC.
(Exact name of registrant as specified in its charter)

INDIANA (State or other jurisdiction of incorporation or organization)	35-2104850 (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 o	Accelerated filer o
Non-accelerated filer ý (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	10	October 31, 2016
Class	Number of Shares	Date

Access to Information

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

Mailing Address: One Vectren Square Evansville, Indiana 47708	Phone Number: (812) 491-4000	Investor Relations Contact: David E. Parker Director, Investor Relations vvcir@vectren.com

Definitions

AFUDC: allowance for funds used during construction	IDEM: Indiana Department of Environmental Management
ASC: Accounting Standards Codification	IURC: Indiana Utility Regulatory Commission
ASU: Accounting Standards Update	kV: Kilovolt
BTU / MMBTU: British thermal units / millions of BTU	MCF / BCF: thousands / billions of cubic feet
DOT: Department of Transportation	MDth / MMDth: thousands / millions of dekatherms
EPA: Environmental Protection Agency	MISO: Midcontinent Independent System Operator
FAC: Fuel Adjustment Clause	MW: megawatts
FASB: Financial Accounting Standards Board	MWh / GWh: megawatt hours / thousands of megawatt hours (gigawatt hours)
FERC: Federal Energy Regulatory Commission	OUCC: 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

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	September 30, 2016	December 31, 2015
ASSETS		
Current Assets		
Cash & cash equivalents	$ 6.0	$ 6.2
Accounts receivable - less reserves of $3.3 & $3.0, respectively	74.9	92.3
Accrued unbilled revenues	41.9	85.7
Inventories	126.4	125.3
Recoverable fuel & natural gas costs	22.9	—
Prepayments & other current assets	52.3	49.0
Total current assets	324.4	358.5
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	0.2	0.2
Other investments	22.9	20.1
Nonutility plant - net	156.7	149.7
Goodwill	205.0	205.0
Regulatory assets	192.7	152.1
Other assets	49.1	32.2
TOTAL ASSETS	$ 4,843.5	$ 4,592.7

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

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

	September 30, 2016	December 31, 2015
LIABILITIES & SHAREHOLDER'S EQUITY		
Current Liabilities		
Accounts payable	$ 161.0	$ 168.5
Payables to other Vectren companies	24.8	25.7
Accrued liabilities	125.9	128.4
Short-term borrowings	131.2	14.5
Current maturities of long-term debt	—	13.0
Total current liabilities	442.9	350.1
Long-Term Debt - Net of Current Maturities	1,379.9	1,379.2
Deferred Credits & Other Liabilities		
Deferred income taxes	821.6	758.4
Regulatory liabilities	450.9	433.9
Deferred credits & other liabilities	148.2	135.9
Total deferred credits & other liabilities	1,420.7	1,328.2
Commitments & Contingencies (Notes 7 - 10)		
Common Shareholder's Equity		
Common stock (no par value)	829.4	799.9
Retained earnings	770.6	735.3
Total common shareholder's equity	1,600.0	1,535.2
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$ 4,843.5	$ 4,592.7

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
OPERATING REVENUES				
Gas utility	$117.7	$108.5	$530.8	$590.1
Electric utility	173.5	164.4	463.3	466.0
Other	0.1	0.1	0.2	0.2
Total operating revenues	291.3	273.0	994.3	1,056.3
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
Other operating	79.4	79.5	250.8	260.8
Depreciation & amortization	55.2	52.4	162.8	156.6
Taxes other than income taxes	12.7	11.8	42.9	43.0
Total operating expenses	227.3	218.9	771.4	841.1
OPERATING INCOME	64.0	54.1	222.9	215.2
Other income - net	6.7	4.0	20.1	13.3
Interest expense	17.2	16.6	52.2	49.5
INCOME BEFORE INCOME TAXES	53.5	41.5	190.8	179.0
Income taxes	18.6	14.6	68.5	64.7
NET INCOME	$34.9	$26.9	$122.3	$114.3

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

VECTREN UTILITY HOLDINGS, INC. 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	$122.3	$114.3
Adjustments to reconcile net income to cash from operating activities:		
Depreciation & amortization	162.8	156.6
Deferred income taxes & investment tax credits	63.4	39.7
Expense portion of pension & postretirement benefit cost	3.1	3.5
Provision for uncollectible accounts	4.8	5.1
Other non-cash items - net	2.1	4.1
Changes in working capital accounts:		
Accounts receivable & accrued unbilled revenues	56.4	112.3
Inventories	(1.1)	(6.5)
Recoverable/refundable fuel & natural gas costs	(30.8)	27.1
Prepayments & other current assets	(6.1)	40.3
Accounts payable, including to Vectren companies & affiliated companies	(32.6)	(58.8)
Accrued liabilities	5.4	3.6
Cash to fund pension plans	(15.0)	(19.6)
Changes in noncurrent assets	(34.9)	(14.9)
Changes in noncurrent liabilities	(4.0)	(4.4)
Net cash provided by operating activities	295.8	402.4
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from:		
Long-term debt - net of issuance costs	—	37.5
Additional capital contribution	29.5	4.7
Requirements for:		
Dividends to parent	(87.0)	(82.8)
Retirement of long-term debt	(13.0)	(5.0)
Net change in short-term borrowings	116.7	(86.2)
Net cash used in financing activities	46.2	(131.8)
CASH FLOWS FROM INVESTING ACTIVITIES		
Proceeds from other investing activities	—	3.1
Changes in restricted cash	2.5	(9.7)
Requirements for:		
Capital expenditures, excluding AFUDC equity	(344.7)	(279.4)
Net cash used in investing activities	(342.2)	(286.0)
Net change in cash & cash equivalents	(0.2)	(15.4)
Cash & cash equivalents at beginning of period	6.2	19.3
Cash & cash equivalents at end of period	$6.0	$3.9

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

VECTREN UTILITY HOLDINGS, INC. AND SUBSIDIARY COMPANIES
NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

1. Organization and Nature of Operations

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

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.

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 March 9, 2016, on Form 10-K. Because of the seasonal nature of the Company's utility 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. Subsidiary Guarantor and Consolidating Information

The Company's three operating utility companies, SIGECO, Indiana Gas, and VEDO are guarantors of Utility Holdings' $350 million in short-term credit facilities, of which $131 million was outstanding at September 30, 2016. The operating utility companies are also guarantors of Utility Holdings' unsecured senior notes with a par value of $996 million outstanding at September 30, 2016. The guarantees are full and unconditional and joint and several, and

Utility Holdings has no direct subsidiaries other than the subsidiary guarantors. However, Utility Holdings does have operations other than those of the subsidiary guarantors. Pursuant to Item 3-10 of Regulation S-X, disclosure of the results of operations and balance sheets of the subsidiary guarantors, which are 100 percent owned, separate from the parent company's operations is required. Following are condensed consolidating financial statements including information on the combined operations of the subsidiary guarantors separate from the other operations of the parent company. Pursuant to a tax sharing agreement, consolidating tax effects, which are calculated on a separate return basis, are reflected at the parent level.

Condensed Consolidating Balance Sheet as of September 30, 2016 (in millions):

ASSETS	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Assets				
Cash & cash equivalents	$ 4.1	$ 1.9	$ —	$ 6.0
Accounts receivable - less reserves	74.7	0.2	—	74.9
Intercompany receivables	30.5	128.8	(159.3)	—
Accrued unbilled revenues	41.9	—	—	41.9
Inventories	126.3	0.1	—	126.4
Recoverable fuel & natural gas costs	22.9	—	—	22.9
Prepayments & other current assets	53.3	2.4	(3.4)	52.3
Total current assets	353.7	133.4	(162.7)	324.4
Utility Plant				
Original cost	6,419.8	—	—	6,419.8
Less: accumulated depreciation & amortization	2,527.3	—	—	2,527.3
Net utility plant	3,892.5	—	—	3,892.5
Investments in consolidated subsidiaries	—	1,545.8	(1,545.8)	—
Notes receivable from consolidated subsidiaries	—	945.4	(945.4)	—
Investments in unconsolidated affiliates	0.2	—	—	0.2
Other investments	22.5	0.4	—	22.9
Nonutility plant - net	1.7	155.0	—	156.7
Goodwill - net	205.0	—	—	205.0
Regulatory assets	176.3	16.4	—	192.7
Other assets	56.5	0.9	(8.3)	49.1
TOTAL ASSETS	$ 4,708.4	$ 2,797.3	$ (2,662.2)	$ 4,843.5

LIABILITIES & SHAREHOLDER'S EQUITY	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Liabilities				
Accounts payable	$ 154.4	$ 6.6	$ —	$ 161.0
Intercompany payables	20.7	—	(20.7)	—
Payables to other Vectren companies	16.9	7.9	—	24.8
Accrued liabilities	110.4	18.9	(3.4)	125.9
Short-term borrowings	—	131.2	—	131.2
Intercompany short-term borrowings	108.1	30.5	(138.6)	—
Total current liabilities	410.5	195.1	(162.7)	442.9
Long-Term Debt				
Long-term debt	384.3	995.6	—	1,379.9
Long-term debt due to VUHI	945.4	—	(945.4)	—
Total long-term debt - net	1,329.7	995.6	(945.4)	1,379.9
Deferred Credits & Other Liabilities				
Deferred income taxes	821.8	(0.2)	—	821.6
Regulatory liabilities	449.6	1.3	—	450.9
Deferred credits & other liabilities	151.0	5.5	(8.3)	148.2
Total deferred credits & other liabilities	1,422.4	6.6	(8.3)	1,420.7
Common Shareholder's Equity				
Common stock (no par value)	842.6	829.4	(842.6)	829.4

Retained earnings	703.2	770.6	(703.2)	770.6
Total common shareholder's equity	1,545.8	1,600.0	(1,545.8)	1,600.0
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$ 4,708.4	$ 2,797.3	$ (2,662.2)	$ 4,843.5

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Condensed Consolidating Balance Sheet as of December 31, 2015 (in millions):

ASSETS	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Assets				
Cash & cash equivalents	$ 5.5	$0.7	$ —	$ 6.2
Accounts receivable - less reserves	92.3	—	—	92.3
Intercompany receivables	51.2	142.9	(194.1)	—
Accrued unbilled revenues	85.7	—	—	85.7
Inventories	125.3	—	—	125.3
Prepayments & other current assets	49.3	4.1	(4.4)	49.0
Total current assets	409.3	147.7	(198.5)	358.5
Utility Plant				
Original cost	6,090.4	—	—	6,090.4
Less: accumulated depreciation & amortization	2,415.5	—	—	2,415.5
Net utility plant	3,674.9	—	—	3,674.9
Investments in consolidated subsidiaries	—	1,467.0	(1,467.0)	—
Notes receivable from consolidated subsidiaries	—	836.0	(836.0)	—
Investments in unconsolidated affiliates	0.2	—	—	0.2
Other investments	19.7	0.4	—	20.1
Nonutility plant - net	1.7	148.0	—	149.7
Goodwill - net	205.0	—	—	205.0
Regulatory assets	135.2	16.9	—	152.1
Other assets	39.6	1.3	(8.7)	32.2
TOTAL ASSETS	$ 4,485.6	$2,617.3	$ (2,510.2)	$ 4,592.7

LIABILITIES & SHAREHOLDER'S EQUITY	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Liabilities				
Accounts payable	$ 161.1	$7.4	$ —	$ 168.5
Intercompany payables	12.4	—	(12.4)	—
Payables to other Vectren companies	25.7	—	—	25.7
Accrued liabilities	120.2	12.6	(4.4)	128.4
Short-term borrowings	—	14.5	—	14.5
Intercompany short-term borrowings	130.5	51.2	(181.7)	—
Current maturities of long-term debt	13.0	—	—	13.0
Total current liabilities	462.9	85.7	(198.5)	350.1
Long-Term Debt				
Long-term debt - net of current maturities & debt subject to tender	383.9	995.3	—	1,379.2
Long-term debt due to VUHI	836.0	—	(836.0)	—
Total long-term debt - net	1,219.9	995.3	(836.0)	1,379.2
Deferred Credits & Other Liabilities				
Deferred income taxes	763.7	(5.3)	—	758.4
Regulatory liabilities	432.5	1.4	—	433.9
Deferred credits & other liabilities	139.6	5.0	(8.7)	135.9
Total deferred credits & other liabilities	1,335.8	1.1	(8.7)	1,328.2
Common Shareholder's Equity				

Common stock (no par value)	813.1	799.9	(813.1)	799.9
Retained earnings	653.9	735.3	(653.9)	735.3
Total common shareholder's equity	1,467.0	1,535.2	(1,467.0)	1,535.2
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$ 4,485.6	$ 2,617.3	$ (2,510.2)	$ 4,592.7

Condensed Consolidating Statement of Income for the three months ended September 30, 2016 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	$ 117.7	$ —	$ —	$ 117.7
Electric utility	173.5	—	—	173.5
Other	—	10.6	(10.5)	0.1
Total operating revenues	291.2	10.6	(10.5)	291.3
OPERATING EXPENSES				
Cost of gas sold	29.1	—	—	29.1
Cost of fuel & purchased power	50.9	—	—	50.9
Other operating	89.6	—	(10.2)	79.4
Depreciation & amortization	49.4	5.8	—	55.2
Taxes other than income taxes	12.3	0.4	—	12.7
Total operating expenses	231.3	6.2	(10.2)	227.3
OPERATING INCOME	59.9	4.4	(0.3)	64.0
Other income - net	6.3	12.0	(11.6)	6.7
Interest expense	16.6	12.5	(11.9)	17.2
INCOME BEFORE INCOME TAXES	49.6	3.9	—	53.5
Income taxes	17.4	1.2	—	18.6
Equity in earnings of consolidated companies, net of tax	—	32.2	(32.2)	—
NET INCOME	$ 32.2	$ 34.9	$ (32.2)	$ 34.9

Condensed Consolidating Statement of Income for the three months ended September 30, 2015 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	$ 108.5	$ —	$ —	$ 108.5
Electric utility	164.4	—	—	164.4
Other	—	10.2	(10.1)	0.1
Total operating revenues	272.9	10.2	(10.1)	273.0
OPERATING EXPENSES				
Cost of gas sold	27.3	—	—	27.3
Cost of fuel & purchased power	47.9	—	—	47.9
Other operating	89.1	—	(9.6)	79.5
Depreciation & amortization	46.2	6.2	—	52.4
Taxes other than income taxes	11.4	0.4	—	11.8
Total operating expenses	221.9	6.6	(9.6)	218.9
OPERATING INCOME	51.0	3.6	(0.5)	54.1
Other income - net	3.3	10.8	(10.1)	4.0
Interest expense	15.9	11.3	(10.6)	16.6
INCOME BEFORE INCOME TAXES	38.4	3.1	—	41.5
Income taxes	13.5	1.1	—	14.6
Equity in earnings of consolidated companies, net of tax	—	24.9	(24.9)	—

NET INCOME	$ 24.9	$ 26.9	$ (24.9)	$ 26.9

Condensed Consolidating Statement of Income for the nine months ended September 30, 2016 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	$ 530.8	$ —	$ —	$ 530.8
Electric utility	463.3	—	—	463.3
Other	—	31.6	(31.4)	0.2
Total operating revenues	994.1	31.6	(31.4)	994.3
OPERATING EXPENSES				
Cost of gas sold	174.6	—	—	174.6
Cost of fuel & purchased power	140.3	—	—	140.3
Other operating	281.2	—	(30.4)	250.8
Depreciation & amortization	144.9	17.8	0.1	162.8
Taxes other than income taxes	41.6	1.3	—	42.9
Total operating expenses	782.6	19.1	(30.3)	771.4
OPERATING INCOME	211.5	12.5	(1.1)	222.9
Other income - net	18.4	36.2	(34.5)	20.1
Interest expense	50.4	37.4	(35.6)	52.2
INCOME BEFORE INCOME TAXES	179.5	11.3	—	190.8
Income taxes	66.5	2.0	—	68.5
Equity in earnings of consolidated companies, net of tax	—	113.0	(113.0)	—
NET INCOME	$ 113.0	$ 122.3	$ (113.0)	$ 122.3

Condensed Consolidating Statement of Income for the nine months ended September 30, 2015 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	$ 590.1	$ —	$ —	$ 590.1
Electric utility	466.0	—	—	466.0
Other	—	30.6	(30.4)	0.2
Total operating revenues	1,056.1	30.6	(30.4)	1,056.3
OPERATING EXPENSES				
Cost of gas sold	235.8	—	—	235.8
Cost of fuel & purchased power	144.9	—	—	144.9
Other operating	289.4	—	(28.6)	260.8
Depreciation & amortization	137.4	19.0	0.2	156.6
Taxes other than income taxes	41.6	1.4	—	43.0
Total operating expenses	849.1	20.4	(28.4)	841.1
OPERATING INCOME	207.0	10.2	(2.0)	215.2
Other income - net	11.7	31.7	(30.1)	13.3
Interest expense	47.6	34.0	(32.1)	49.5
INCOME BEFORE INCOME TAXES	171.1	7.9	—	179.0
Income taxes	63.6	1.1	—	64.7
Equity in earnings of consolidated companies, net of tax	—	107.5	(107.5)	—
NET INCOME	$ 107.5	$ 114.3	$ (107.5)	$ 114.3

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Condensed Consolidating Statement of Cash Flows for the nine months ended September 30, 2016 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH PROVIDED BY OPERATING ACTIVITIES	$ 255.0	$ 40.8	$ —	$ 295.8
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from				
Long-term debt - net of issuance costs	109.4	—	(109.4)	—
Additional capital contribution from parent	29.5	29.5	(29.5)	29.5
Requirements for:				
Dividends to parent	(63.7)	(87.0)	63.7	(87.0)
Retirement of long term debt	(13.0)	—	—	(13.0)
Net change in intercompany short-term borrowings	(22.3)	(20.8)	43.1	—
Net change in short-term borrowings	—	116.7	—	116.7
Net cash used in financing activities	39.9	38.4	(32.1)	46.2
CASH FLOWS FROM INVESTING ACTIVITIES				
Proceeds from:				
Consolidated subsidiary distributions	—	63.7	(63.7)	—
Requirements for:				
Capital expenditures, excluding AFUDC equity	(319.6)	(25.1)	—	(344.7)
Consolidated subsidiary investments	—	(29.5)	29.5	—
Changes in restricted cash	2.5	—	—	2.5
Net change in long-term intercompany notes receivable	—	(109.4)	109.4	—
Net change in short-term intercompany notes receivable	20.8	22.3	(43.1)	—
Net cash used in investing activities	(296.3)	(78.0)	32.1	(342.2)
Net change in cash & cash equivalents	(1.4)	1.2	—	(0.2)
Cash & cash equivalents at beginning of period	5.5	0.7	—	6.2
Cash & cash equivalents at end of period	$ 4.1	$ 1.9	$ —	$ 6.0

Condensed Consolidating Statement of Cash Flows for the nine months ended September 30, 2015 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH PROVIDED BY OPERATING ACTIVITIES	$ 351.7	$ 50.7	$ —	$ 402.4
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from:				
Long-term debt, net of issuance costs	37.5	—	—	37.5
Additional capital contribution from parent	4.7	4.7	(4.7)	4.7
Requirements for:				
Dividends to parent	(77.4)	(82.8)	77.4	(82.8)
Retirement of long term debt	(5.0)	—	—	(5.0)
Net change in intercompany short-term borrowings	1.7	46.5	(48.2)	—
Net change in short-term borrowings	—	(86.2)	—	(86.2)
Net cash used in financing activities	(38.5)	(117.8)	24.5	(131.8)
CASH FLOWS FROM INVESTING ACTIVITIES				
Proceeds from:				
Consolidated subsidiary distributions	—	77.4	(77.4)	—
Other investing activities	—	3.1	—	3.1
Requirements for:				

Capital expenditures, excluding AFUDC equity	(260.8)	(18.6)	—	(279.4)
Consolidated subsidiary investments	—	(4.7)	4.7	—
Changes in restricted cash	(9.7)	—	—	(9.7)
Net change in short-term intercompany notes receivable	(46.5)	(1.7)	48.2	—
Net cash used in investing activities	(317.0)	55.5	(24.5)	(286.0)
Net change in cash & cash equivalents	(3.8)	(11.6)	—	(15.4)
Cash & cash equivalents at beginning of period	6.9	12.4	—	19.3
Cash & cash equivalents at end of period	$ 3.1	$ 0.8	$ —	$ 3.9

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 as a component of operating revenues, which totaled $5.3 million and $5.0 million in the three months ended September 30, 2016 and 2015, respectively. For 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. 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 $43.0 million and $18.1 million, respectively.

6. Transactions with Other Vectren Companies and Affiliates

Vectren Infrastructure Services Corporation (VISCO)
VISCO, a wholly owned subsidiary of Vectren, provides underground pipeline construction and repair services. VISCO's customers include Utility Holdings' utilities and fees incurred by Utility Holdings and its subsidiaries 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. Amounts owed to VISCO at September 30, 2016 and December 31, 2015 are included in Payables to other Vectren companies in the Condensed Consolidated Balance Sheets.

Support Services & Purchases
Vectren provides corporate and general and administrative services to the Company and allocates certain costs to the Company, including costs for share-based compensation and for pension and other postretirement benefits that are not directly charged to subsidiaries. These costs are allocated using various allocators, including number of employees, number of customers and/or the level of payroll, revenue contribution and capital expenditures. Allocations are at cost. For the three months ended September 30, 2016 and 2015, Utility Holdings received corporate allocations totaling $11.7 million and $12.0 million, respectively. For the nine months ended September 30, 2016 and 2015, Utility Holdings received corporate allocations totaling $44.4 million and $39.5 million, respectively. The increase in corporate allocations in 2016 compared to 2015 is driven by higher performance-based compensation primarily due to the increase in Vectren's stock price.

The Company does not have share-based compensation plans and pension and other postretirement plans separate from Vectren and allocated costs include participation in Vectren's plans. The allocation methodology for retirement costs is consistent with FASB guidance related to “multiemployer” benefit accounting.

7. Commitments & Contingencies

Commitments
The Company has 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.

8. 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)
In March of 2016, PHMSA published a notice of proposed rulemaking (NPRM) on the safety of gas transmission and gathering lines. The proposed rule addresses many of the remaining requirements of the 2011 Pipeline Safety Act, with a particular focus on extending integrity management rules to address a much larger portion of the natural gas infrastructure and adds requirements to address broader threats to the integrity of a pipeline system. The Company is evaluating the impact that these proposed rules will have on its integrity management programs and transmission and distribution systems. 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.

9. 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 the Company a CPCN for the NOV-required equipment. On July 21, 2016, the appellants initiated an appeal of the IURC's June 22, 2016 Order challenging the findings made by the IURC. 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.

10. Environmental Matters

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

With the trend toward stricter standards, greater regulation, and more extensive permit requirements, the Company's investment in compliant infrastructure and the associated operating costs have increased and are expected to increase in the future. Similar to the costs associated with federal mandates in the Pipeline Safety Law, 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 the Company a CPCN for the NOV-required equipment. On July 21, 2016, the appellants initiated an appeal of the IURC's June 22, 2016 Order challenging the findings made by the IURC. 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 CO_2/MWh to be achieved by 2030. The new rule gives states the option of seeking a two-year extension from the initial deadline of September 2016 to submit a final state implementation plan (SIP). Under the CPP, states have the flexibility to include energy efficiency and other measures should they choose to implement a SIP as provided in the final rule. While states are given an interim goal (1,451 lb CO_2/MWh for Indiana), the final rule gives states the flexibility to shape their own emissions reduction over the 2022-2029 time period. The final rule was published in the Federal Register on October 23, 2015 and that action was immediately followed by litigation initiated by Indiana and 23 other states as a coalition challenging the rule. In January of 2016, the reviewing court denied the states' and other parties requests to stay the implementation of the CPP pending completion of judicial review. On January 26, 2016, 29 states and state agencies, including the 24 state coalition referenced above, filed a request for immediate stay with the U.S. Supreme Court. On February 9, 2016, the U.S. Supreme Court granted a stay to delay the regulation while being challenged in court. Extensive oral argument was held in September. The stay will remain in place while the lower court concludes its review. Among other things, the stay delays the requirement to submit a final SIP by the original September 2016 deadline and could extend implementation to 2024.

In the event that a state does not submit a SIP, the EPA also released a proposed federal implementation plan (FIP), which would be imposed on those states without an approved SIP. The proposed FIP would apply an emission rate requirement directly on generating units. Under the proposed FIP, the CO_2 emission rate limit for coal-fired units would start at 1,671 lbs CO_2/MWh in 2022 and decrease to a final emission rate cap of 1,305 lbs CO_2/MWh by 2030. While the FIP emission rate cap appears to be slightly less stringent than the state reduction goal for Indiana, the cap would apply directly to generating units and these units would not have the benefit of averaging emission rates with rates from zero-carbon sources as would be available in a SIP. Purchases of emission credits from zero-carbon sources can be made for compliance. The FIP will be subject to extensive public comments prior to finalization. Whether Indiana will file a SIP has yet to be determined. Pending that determination, the electric utilities in Indiana will continue to encourage the state's designated agency to analyze various compliance options and the possible integration into a state plan submittal.

At the time of release of the CPP, Indiana was the 5th largest carbon emitter in the nation in tons of CO_2 produced from electric generation. The Company's share of total tons of CO_2 generated by Indiana's electric utilities has historically been less than 6 percent. Since 2005 through 2015, the Company has achieved a reduction in emissions of CO_2 of 31 percent (on a tonnage basis) through the retirement of F.B. Culley Unit 1, expiration of municipal contracts, electric conservation, the addition of renewable generation, and the installation of more efficient dense pack turbine technology. Since emissions are further impacted by coal burn reductions and energy efficiency programs, the Company's emissions of CO_2 can vary year to year. With respect to renewable generation, in 2008 and 2009, the Company executed long-term purchase power commitments for a total of 80 MW of wind energy. The Company currently has approximately 4 percent of its electricity being provided by energy sources other than coal and natural gas, due to the long-term wind contracts and landfill gas investment. With respect to CO_2 emission rate, since 2005 through 2015, the Company has lowered its CO_2 emission rate (as measured in lbs CO_2/MWh) from 1,967 lbs CO_2/MWh to 1,922 lbs CO_2/MWh, for a reduction of 3 percent. The Company's CO_2 emission rate of 1,922 lbs CO_2/MWh is basically the same as Indiana's average CO_2 emission rate of 1,923 lbs CO_2/MWh. The Company plans to consider these reductions in CO_2 emissions and renewable generation in future discussions with the state to develop a possible state implementation plan.

Impact of Legislative Actions & Other Initiatives is Unknown

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

In addition to the federal programs, the United States and 194 other countries agreed by consensus to limit GHG emissions beginning after 2020 in the 2015 United Nations Framework Convention on Climate Change Paris Agreement. The United States has proposed a 26-28 percent GHG emission reduction from 2005 levels by 2025. As previously noted, since 2005 through 2015, the Company has achieved reduced emissions of 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.

11. 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 Carrying Amount	September 30, 2016 Est. Fair Value	December 31, 2015 Carrying Amount	December 31, 2015 Est. Fair Value
Long-term debt	$1,379.9	$1,558.5	$1,392.2	$1,495.0
Short-term borrowings	131.2	131.2	14.5	14.5
Cash & cash equivalents	6.0	6.0	6.2	6.2
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 recorded at fair value outstanding, and no material assets or liabilities valued using Level 3 inputs.

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.

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

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

Leases

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

Stock Compensation

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

Other Recently Issued Standards
Management believes 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. Segment Reporting

The Company’s operations consist of regulated operations and other operations that provide information technology and other support services to those regulated operations. The Company segregates its regulated operations between a Gas Utility

Services operating segment and an Electric Utility Services operating segment. The Gas Utility Services segment provides natural gas distribution and transportation services to nearly two-thirds of Indiana and 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 Company reports three operating segments: Gas Utility Services, Electric Utility Services, and Other Shared Service 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 September 30,		Nine Months Ended September 30,	
(In millions)	2016	2015	2016	2015
Revenues				
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 Revenues	$291.3	$273.0	$994.3	$1,056.3
Profitability Measure - Net Income (Loss)				
Gas Utility Services	$0.9	$(3.3)	$46.0	$40.4
Electric Utility Services	31.3	28.2	67.0	67.1
Other Operations	2.7	2.0	9.3	6.8
Total Net Income	$34.9	$26.9	$122.3	$114.3

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION

Description of the Business

Vectren Utility Holdings, Inc. (the Company, Utility Holdings, or VUHI), an Indiana corporation, was formed on March 31, 2000 to serve as the intermediate holding company for Vectren Corporation's (Vectren) three operating public utilities: Indiana Gas Company, Inc. (Indiana Gas or Vectren Energy Delivery of Indiana - North), Southern Indiana Gas and Electric Company (SIGECO or Vectren Energy Delivery of Indiana - South), and Vectren Energy Delivery of Ohio, Inc. (VEDO). Utility Holdings also earns a return on shared assets that provide information technology and other services to the three utilities. Vectren, an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana and was organized on June 10, 1999. Both Vectren and Utility Holdings are holding companies as defined by the Energy Policy Act of 2005 (Energy Act).

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 segregates its regulatory utility operations between a Gas Utility Services operating segment and an Electric Utility Services operating segment.

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 2015 annual report filed on Form 10-K.

Executive Summary of Consolidated Results of Operations

In the third quarter of 2016, Utility Holdings' earnings were $34.9 million, compared to $26.9 million in 2015. In the nine months ended September 30, 2016, Utility Holdings earned $122.3 million, compared to $114.3 million in 2015. Both the quarter and year to date periods reflect increases in gas utility margin from returns on the Indiana and Ohio infrastructure investment programs and increases in large customer usage in both the quarter and year to date periods compared to 2015. Though earnings in the third quarter of 2016 were favorably impacted by an increase in customer margin as cooling degree days in 2016 were higher compared to 2015, the increase in the year to date period is offset by decreases in gas and electric utility margin due to warmer weather in the first quarter of 2016 as compared to the significantly colder first quarter of 2015. Results in both the quarter and year to date periods reflect lower wholesale power margin due to lower market pricing compared to 2015 and reduced generating unit availability. Operating expenses in the year to date period compared to 2015 were favorably impacted by reduced power plant and energy delivery maintenance costs in 2016, offset somewhat by higher performance-based compensation expense primarily driven by an increase in the Company's stock price.

Results of Operations

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 generally 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 September 30,		Nine Months Ended September 30,	
(In millions)	2016	2015	2016	2015
Gas utility revenues	$117.7	$108.5	$530.8	$590.1
Cost of gas sold	29.1	27.3	174.6	235.8
Total gas utility margin	$88.6	$81.2	$356.2	$354.3
Margin attributed to:				
Residential & commercial customers	$67.1	$61.3	$272.3	$257.3
Industrial customers	14.2	13.0	47.3	45.3
Other	1.4	1.5	5.7	7.4
Regulatory expense recovery mechanisms	5.9	5.4	30.9	44.3
Total gas utility margin	$88.6	$81.2	$356.2	$354.3
Sold & transported volumes in MMDth attributed to:				
Residential & commercial customers	5.9	6.3	65.2	79.1
Industrial customers	28.0	26.3	93.8	92.7
Total sold & transported volumes	33.9	32.6	159.0	171.8

Gas utility margins were $88.6 million and $356.2 million for the three and nine months ended September 30, 2016, and compared to 2015, increased $7.4 million quarter over quarter and $1.9 million year over year. While rate designs substantially limit the impact of weather on small customer margin, the warmer weather in the first quarter of 2016 did decrease sold and transported volumes, resulting in lower year to date regulatory expense recovery margin and a corresponding decrease in operating expenses. In 2016 as compared to the 2015 year to date period, excluding margin from regulatory expense recovery mechanisms which decreased $13.4 million, gas utility margin increased $15.3 million. Margin was favorably impacted by increased returns on infrastructure investment programs in Indiana and Ohio of $5.7 million quarter over quarter and $16.0 million year to date compared to 2015. Margin in both periods also reflects increases in small customer count.

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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 September 30,		Nine Months Ended September 30,	
(In millions)	2016	2015	2016	2015
Electric utility revenues	$173.5	$164.4	$463.3	$466.0
Cost of fuel & purchased power	50.9	47.9	140.3	144.9
Total electric utility margin	$122.6	$116.5	$323.0	$321.1
Margin attributed to:				
Residential & commercial customers	$79.4	$76.8	$202.8	$203.3
Industrial customers	30.5	27.6	84.8	82.9
Other	0.4	0.8	2.6	2.3
Regulatory expense recovery mechanisms	4.6	3.0	11.6	8.2
Subtotal: retail	$114.9	$108.2	$301.8	$296.7
Wholesale power & transmission system margin	7.7	8.3	21.2	24.4
Total electric utility margin	$122.6	$116.5	$323.0	$321.1
Electric volumes sold in GWh attributed to:				
Residential & commercial customers	830.0	801.7	2,122.6	2,147.4
Industrial customers	755.6	653.1	2,110.0	2,045.5
Other customers	5.2	5.1	16.6	15.9
Total retail volumes sold	1,590.8	1,459.9	4,249.2	4,208.8

Retail
Electric retail utility margins were $114.9 million and $301.8 million for the three and nine months ended September 30, 2016, and compared to 2015, increased by $6.7 million in the quarter and $5.1 million year to date. Electric results, which are not protected by weather normalizing mechanisms, reflect a $3.6 million increase in customer margin in the quarter related to weather as annualized cooling degree days in the third quarter of 2016 were 115 percent of normal compared to 103 percent of normal in 2015. For the year to date period, electric margin was unfavorably impacted by weather, primarily in the first quarter 2016, and resulted in a year to date decrease of $0.6 million in small customer margin year over year. Electric margin had favorable results related to regulatory expense recovery mechanisms, which increased $1.6 million quarter over quarter and $3.4 million year to date compared to 2015, driven primarily by a corresponding increase in operating expenses associated with MISO administrative expenses and electric efficiency programs. Additionally, results reflect increases in large customer usage of $2.9 million quarter over quarter and $1.8 million year over year, primarily driven by increased customer throughput and timing of customer plant maintenance. Small customer usage unfavorably impacted results $1.1 million quarter over quarter and $0.5 million year to date compared to 2015.

On December 3, 2013, SABIC Innovative Plastics (SABIC), a large industrial utility customer of the Company, announced its plans to build a cogeneration (cogen) facility to be operational at the end of 2016 or early in 2017, in order to generate power to meet a significant portion of its ongoing power needs. Electric service was provided to SABIC by the Company under a long-term contract that expired on May 2, 2016. At that date, SABIC became a tariff customer. The cogen facility is expected to provide approximately 85 MW of capacity. The Company will continue to provide all of SABIC's power requirements above the approximate 85 MW capacity of the cogen. Once the cogen is operational, backup power will be provided under approved tariff rates.

Margin from Wholesale Electric Activities

The Company earns a return on electric transmission projects constructed by the Company in its service territory that meet the criteria of 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:

(In millions)	Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
MISO Transmission system margin	$ 7.7	$ 7.6	$ 19.5	$ 20.4
MISO Off-system margin	—	0.7	1.7	4.0
Total wholesale margin	$ 7.7	$ 8.3	$ 21.2	$ 24.4

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms and other transmission system operations, totaled $7.7 million and $7.6 million during the three months ended September 30, 2016 and 2015, respectively. Transmission system margin was $19.5 million and $20.4 million during the nine months ended September 30, 2016 and 2015, respectively. As of September 30, 2016, the Company has invested $157.7 million in qualifying projects. The net plant balance for these projects totaled $137.7 million at September 30, 2016. These projects include an interstate 345 kV transmission line that connects the Company's A.B. Brown Generating Station to a generating station in Indiana owned by Duke Energy to the north and to a generating station in Kentucky owned by Big Rivers Electric Corporation to the south; a substation; and another transmission line. Once placed into service, these projects earn a FERC approved equity rate of return on the net plant balance and recover operating expenses. In September 2016, the FERC issued a final order authorizing the transmission owners to receive a 10.32 percent base ROE plus, a separately approved 50 basis point adder versus the previously authorized 12.38 percent. The Company has reflected these outcomes in its financial statements. The 345 kV project is the largest of these qualifying projects, with a cost of $106.8 million that earned the FERC approved equity rate of return, including while under construction.

In the third quarter of 2016 there was no margin from off system sales, compared to $0.7 million in 2015. For the nine months ended September 30, 2016, margin from off-system sales was $1.7 million compared to $4.0 million in 2015. 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 is shared equally with customers. Results for the periods presented reflect lower market pricing due primarily to low natural gas prices and reduced generating unit availability.

Other Operating

During the third quarter of 2016, other operating expenses were $79.4 million, and were flat compared to the third quarter of 2015. For the nine months ended September 30, 2016, other operating expenses were $250.8 million, a decrease of $10.0 million, compared to 2015. Excluding costs that are recovered directly in margin, other operating expenses decreased $2.2 million quarter over quarter and $3.4 million in the year to date period when compared to 2015. The quarter to date and year to date periods were impacted by changes in performance-based compensation driven by movements in the Company's stock price. In the year to date period, the increase in operating expenses due to performance-based compensation was offset by decreases in costs primarily related to the timing of power plant maintenance costs and lower energy delivery expenses due to the colder weather in 2015.

Depreciation & Amortization

In the third quarter of 2016, depreciation and amortization expense was $55.2 million, compared to $52.4 million in 2015. For the nine months ended September 30, 2016, depreciation and amortization expense was $162.8 million, which represents an increase of $6.2 million compared to 2015. The increase reflects increased plant placed in service, which is largely driven by increased gas utility plant as a result of the Indiana and Ohio infrastructure programs.

Taxes Other Than Income Taxes

Taxes other than income taxes were $12.7 million for the third quarter of 2016, an increase of $0.9 million, compared to 2015. Year to date, taxes other than income taxes were flat compared to the year to date period in 2015. Fluctuations in the periods presented are driven by changes in gas costs and thus fluctuations in revenues and related revenue taxes as well as changes in property taxes.

Other Income - Net

Other income-net reflects income of $6.7 million for the third quarter of 2016, an increase of $2.7 million, compared to 2015. Year to date, other income-net reflects income of $20.1 million, compared to $13.3 million in 2015. The increases are primarily due to increased allowance for funds used during construction (AFUDC) driven by increased capital expenditures related to gas utility infrastructure replacement investments.

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)

In March of 2016, PHMSA published a notice of proposed rulemaking (NPRM) on the safety of gas transmission and gathering lines. The proposed rule addresses many of the remaining requirements of the 2011 Pipeline Safety Act, with a particular focus on extending integrity management rules to address a much larger portion of the natural gas infrastructure and adds requirements to address broader threats to the integrity of a pipeline system. The Company is evaluating the impact that these proposed rules will have on its integrity management programs and transmission and distribution systems. 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.

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 the Company a CPCN for the NOV-required equipment. On July 21, 2016, the appellants initiated an appeal of the IURC's June 22, 2016 Order challenging the findings made by the IURC. 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

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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.

Environmental Matters

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

With the trend toward stricter standards, greater regulation, and more extensive permit requirements, the Company's investment in compliant infrastructure and the associated operating costs have increased and are expected to increase in the future. Similar to the costs associated with federal mandates in the Pipeline Safety Law, 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 the Company a CPCN for the NOV-required equipment. On July 21, 2016, the appellants initiated an appeal of the IURC's June 22, 2016 Order challenging the findings made by the IURC. 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

Utility Holdings is committed to responsible environmental stewardship and conservation efforts, and if a national climate change policy is implemented, believes it should have the following elements:

- An inclusive scope that involves all sectors of the economy and sources of greenhouse gases, and recognizes early actions and investments made to mitigate greenhouse gas emissions;
- Provisions for enhanced use of renewable energy sources as a supplement to baseload generation including effective energy conservation, demand side management, and generation efficiency measures;
- Inclusion of incentives for research and development and investment in advanced clean coal technology; and
- A strategy supporting alternative energy technologies and biofuels and continued increase in the domestic supply of natural gas and oil to reduce dependence on foreign oil.

Based on data made available through the Electronic Greenhouse Gas Reporting Tool (e-GRRT) maintained by the EPA, the Company’s direct CO_2 emissions from its fossil fuel electric generation that report under the Acid Rain Program were less than one half of one percent of all emissions in the United States from similar sources. Emissions from other Company operations, including those from its natural gas distribution operations and the greenhouse gas emissions the Company is required to report on behalf of its end use customers, are similarly available through the EPA’s e-GRRT database and reporting tool.

Current Initiatives to Increase Conservation & Reduce Emissions

The Company is committed to a policy that reduces greenhouse gas emissions and conserves energy usage. Evidence of this commitment includes:

- Since 2005 and through 2015, the Company has achieved a reduction in emissions of CO_2 of 31 percent (on a tonnage basis) through the retirement of F.B. Culley Unit 1, expiration of municipal contracts, electric conservation, the addition of renewable generation, and the installation of more efficient dense pack turbine technology.
- 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 Core level certification by the Global Reporting Initiative. This certification demonstrates the Company's commitment to sustainability and denotes transparency in operations;
- Implementing home and business energy efficiency initiatives in the Company’s Indiana and Ohio gas utility service territories such as offering rebates on high efficiency furnaces, programmable thermostats, and insulation and duct sealing;
- Implementing home and business energy efficiency initiatives in the electric service territory such as rebate programs on central air conditioning units, LED lighting, home weatherization and energy audits;
- Building a renewable energy portfolio to complement base load generation in advance of mandated renewable energy portfolio standards;
- Evaluating potential carbon requirements with regard to new generation, other fuel supply sources, and future environmental compliance plans;
- Further reducing the Company’s carbon footprint by building a more sustainable vehicle fleet with lower overall fuel consumption;
- Reducing methane emissions through becoming a founding partner in the EPA Natural Gas STAR Methane Challenge Program. The Company's primary method for reducing methane emissions is through continued replacement of bare steel and cast iron gas distribution pipeline assets.

On August 3, 2015, the EPA released its final 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 CO_2 emission rate limit for coal-fired units would start at 1,671 lbs CO_2/MWh in 2022 and decrease to a final emission rate cap of 1,305 lbs CO_2/MWh by 2030. While the FIP emission rate cap appears to be slightly less stringent than the state reduction goal for Indiana, the cap would apply directly to generating units and these units would not have the benefit of averaging emission rates with rates from zero-carbon sources as would be available in a SIP. Purchases of emission credits from zero-carbon sources can be made for compliance. The FIP will be subject to extensive public comments prior to finalization. Whether Indiana will file a SIP has yet to be determined. Pending that determination, the electric utilities in Indiana will continue to encourage the state's designated agency to analyze various compliance options and the possible integration into a state plan submittal.

At the time of release of the CPP, Indiana was the 5th largest carbon emitter in the nation in tons of CO_2 produced from electric generation. The Company's share of total tons of CO_2 generated by Indiana's electric utilities has historically been less than 6 percent. Since 2005 through 2015, the Company has achieved a reduction in emissions of CO_2 of 31 percent (on a tonnage basis) through the retirement of F.B. Culley Unit 1, expiration of municipal contracts, electric conservation, the addition of renewable generation, and the installation of more efficient dense pack turbine technology. Since emissions are further impacted by coal burn reductions and energy efficiency programs, the Company's emissions of CO_2 can vary year to year. With respect to renewable generation, in 2008 and 2009, the Company executed long-term purchase power commitments for a total of 80 MW of wind energy. The Company currently has approximately 4 percent of its electricity being provided by energy sources other than coal and natural gas, due to the long-term wind contracts and landfill gas investment. With respect to CO_2 emission rate, since 2005 through 2015, the Company has lowered its CO_2 emission rate (as measured in lbs CO_2/MWh) from 1,967 lbs CO_2/MWh to 1,922 lbs CO_2/MWh, for a reduction of 3 percent. The Company's CO_2 emission rate of 1,922 lbs CO_2/MWh is basically the same as Indiana's average CO_2 emission rate of 1,923 lbs CO_2/MWh. The Company plans to consider these reductions in CO_2 emissions and renewable generation in future discussions with the state to develop a possible state implementation plan.

Impact of Legislative Actions & Other Initiatives is Unknown

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

In addition to the federal programs, the United States and 194 other countries agreed by consensus to limit GHG emissions beginning after 2020 in the 2015 United Nations Framework Convention on Climate Change Paris Agreement. The United States has proposed a 26-28 percent GHG emission reduction from 2005 levels by 2025. As previously noted, since 2005 through 2015, the Company has achieved reduced emissions of 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.

Impact of Recently Issued Accounting Guidance

Revenue Recognition Guidance
In May 2014, the FASB issued new accounting guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for GAAP. The amendments in this guidance state that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This new guidance requires improved disclosures to help users of financial statements better understand the nature, amount, timing, and uncertainty of revenue that is recognized.

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

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

adoption. The Company is currently evaluating the standard to determine the impact it will have on the financial statements.

Stock Compensation

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

Other Recently Issued Standards
Management believes 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.

Financial Condition

Utility Holdings funds the short-term and long-term financing needs of its utility subsidiary operations. Vectren does not guarantee Utility Holdings' debt. Utility Holdings' outstanding long-term and short-term borrowing arrangements are jointly and severally guaranteed by Indiana Gas, SIGECO, and VEDO. The guarantees are full and unconditional and joint and several, and Utility Holdings has no direct subsidiaries other than the subsidiary guarantors. Information about the subsidiary guarantors as a group is included in Note 3 to the condensed consolidated financial statements. Utility Holdings' long-term debt, including current maturities, outstanding at September 30, 2016 approximated $996 million. As of September 30, 2016, Utility Holdings had $131 million 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 tax exempt debt to fund qualifying pollution control capital expenditures. Total Indiana Gas and SIGECO long-term debt, including current maturities, outstanding at September 30, 2016, was approximately $384 million. Utility Holdings' operations have historically been the primary funding source for Vectren's common stock dividends.

The credit ratings of the senior unsecured debt of Utility Holdings, SIGECO and Indiana Gas, at September 30, 2016, are A-/A2 as rated by Standard and Poor's Ratings Services (Standard and Poor's) and Moody's Investors Service (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 50-60 percent of long-term capitalization. This objective may have varied, and will vary, depending on particular business opportunities, capital spending requirements, execution of long-term financing plans, and seasonal factors that affect the Company's operations. The Company's equity component was 54 percent and 52 percent of long-term capitalization at September 30, 2016 and December 31, 2015, respectively. Long-term capitalization includes long-term debt, including current maturities, as well as common shareholder's 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 September 30, 2016, the Company is 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. The Company anticipates funding future capital expenditures and dividends principally through internally generated funds supplemented with incremental external debt financing. However, the resources required for capital investment remain uncertain for a variety of factors including, but not limited to, expanded environmental regulations on power generation and regulatory initiatives involving gas pipeline infrastructure replacement. These regulations may result in the need to raise additional capital in the coming years.

The Company routinely seeks approval at the IURC and the PUCO for long-term financing authority at the individual utility level. While the Company has no plans to issue any long-term financing at the utility level, this authority allows for the flexibility for each utility to issue debt and equity securities to third parties or to issue debt and equity securities to the Company and thus receive some of the proceeds from various Company issuances to third parties on the same terms as those obtained by the Company. It is expected that the majority of the long-term debt needs of the utilities will be met through these debt issuances by the Company, some or all of which are then reloaned to the individual utilities. The most recent financing Orders for SIGECO and Indiana Gas were received on March 4, 2015. On June 15, 2016 an Order for long-term financing authority of $70 million of long-term debt and $75 million of equity financing was received from the PUCO for VEDO. Orders for SIGECO and Indiana Gas expire in December 2016 and the Order for VEDO expires in June 2017.

Consolidated Short-Term Borrowing Arrangements

At September 30, 2016, the Company has $350 million of short-term borrowing capacity. As reduced by borrowings currently outstanding, approximately $219 million was available at September 30, 2016. This short-term credit facility is available until October 31, 2019 and can be used to supplement working capital needs and to fund capital investments and debt redemptions.

The Company has historically funded its short-term borrowing needs through the commercial paper market but maintains the ability to use the short-term borrowing facility when necessary. Following is certain information regarding these short-term borrowing arrangements.

(In millions)	2016	2015
As of September 30		
Balance Outstanding	$131.2	$70.2
Weighted Average Interest Rate	0.67%	0.37%
Year to Date Average - September 30		
Balance Outstanding	$28.2	$41.8
Weighted Average Interest Rate	0.62%	0.38%
Maximum Month End Balance Outstanding	$131.2	$121.5

(In millions)	2016	2015
Quarterly Average - September 30		
Balance Outstanding	$73.8	$52.9
Weighted Average Interest Rate	0.63%	0.37%
Maximum Month End Balance Outstanding	$131.2	$70.2

California Department of Insurance

The California Department of Insurance issued a press release in January 2016 calling for all insurance companies doing business in California to disclose annually carbon-based investments and to voluntarily divest of their investments in thermal coal. The position on voluntary divestiture taken by the California Insurance Commissioner, as defined, applies to electric utilities that derive more than 50 percent of their energy from thermal coal plants. The Company has a significant portion of its outstanding long term debt held by various insurance companies and placed through the private debt markets. The Company continues to monitor development in this area but anticipates no immediate impact.

Bonus Depreciation

On December 18, 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. The PATH Act allows for 50 percent bonus depreciation for property placed in service in 2015 - 2017; 40 percent in 2018; and 30 percent in 2019. Including the impact of alternative minimum tax credits that will be utilized in future periods, the extension of 50 percent bonus depreciation is expected to result in an approximate $40 million positive impact to cash flows for the 2016 tax year.

Potential Uses of Liquidity

Pension Funding Obligations

In 2016, Vectren contributed $15 million to its qualified pension plans and Utility Holdings funded this contribution. Vectren does not anticipate making further contributions in 2016.

Planned Capital Expenditures

Capital expenditures are estimated at approximately $150 million for the remainder of 2016.

Contractual Obligations

The Company’s contractual obligations primarily consist of debt issued by the Company and its subsidiaries as well as certain plant and nonutility plant purchase commitments. For the nine months ended September 30, 2016, 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, 2015, other than those which occur in the normal and ordinary course of business and those mentioned below.

The Company has 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.

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 $295.8 million and $402.4 million for the nine months ended September 30, 2016 and 2015, respectively. The decrease is driven primarily by changes in certain working capital accounts due to weather that was significantly milder in 2016. Additionally, the timing of payments and refunds related to income taxes decreased cash flow period over period. Tax payments were impacted by the extension of bonus depreciation late in 2014.

Financing Cash Flow
Net cash flow required for financing activities was an inflow of $46.2 million during the nine months ended September 30, 2016 compared to a cash outflow of $131.8 million during the nine months ended September 30, 2015. The decrease in cash flow required for financing activities was primarily related to utilization of a greater amount of cash on hand in 2015 to retire outstanding debt. The Company also received additional capital provided from Vectren to help fund capital expenditures in 2016 compared to 2015.

Investing Cash Flow
Cash flow required for investing activities was $342.2 million and $286.0 million during the nine months ended September 30, 2016 and 2015, respectively. The primary use of cash in both periods reflects expenditures for utility 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 unfavorable or unusual weather conditions; catastrophic weather-related damage; unusual maintenance or repairs; unanticipated changes to coal and natural gas costs; unanticipated changes to gas transportation and storage costs, or availability due to higher demand, shortages, transportation problems or other developments; environmental or pipeline incidents; transmission or distribution incidents; unanticipated changes to electric energy supply costs, or availability due to demand, shortages, transmission problems or other developments; or electric transmission or gas pipeline system constraints.
- New legislation, litigation and government regulation, such as changes in or additions to tax laws or rates, pipeline safety regulation and environmental laws, including laws governing air emissions, including carbon, waste water discharges and

the handling and disposal of coal combustion residuals that could impact the continued operation, and/or cost recovery of our generation plants and related assets. These compliance costs could substantially change the nature of the Company's generation fleet.

- Catastrophic events such as fires, earthquakes, explosions, floods, ice storms, tornadoes, terrorist acts, physical attacks, cyber attacks, or other similar occurrences could adversely affect the Company's facilities, operations, financial condition, results of operations, and reputation.
- Increased competition in the energy industry, including the effects of industry restructuring, unbundling, and other sources of energy.
- Regulatory factors such as uncertainty surrounding the composition of state regulatory commissions, adverse regulatory changes, unanticipated changes in rate-setting policies or procedures, recovery of investments and costs made under regulation, interpretation of regulatory-related legislation by the IURC and/or PUCO and appellate courts that review decisions issued by the agencies, and the frequency and timing of rate increases.
- Financial, regulatory or accounting principles or policies imposed by the Financial Accounting Standards Board; the Securities and Exchange Commission; the Federal Energy Regulatory Commission; state public utility commissions; state entities which regulate electric and natural gas transmission and distribution, natural gas gathering and processing, electric power supply; and similar entities with regulatory oversight.
- Economic conditions including the effects of inflation 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; economic impacts of changes in business strategy on both gas and electric large customers; lower residential and commercial customer counts; variance from normal population growth and changes in customer mix; and higher operating expenses.
- Volatile natural gas and coal commodity prices and the potential impact on customer consumption, uncollectible accounts expense, unaccounted for gas and interest expense.
- Volatile oil prices and the potential impact on customer consumption and price of other fuel commodities.
- Direct or indirect effects on the Company's business, financial condition, liquidity and results of operations resulting from changes in credit ratings, changes in interest rates, and/or changes in market perceptions of the utility industry and other energy-related industries.
- Employee or contractor workforce factors including changes in key executives, collective bargaining agreements with union employees, aging workforce issues, work stoppages, or pandemic illness.
- Risks associated with material business transactions such as acquisitions and divestitures, including, without limitation, legal and regulatory delays; the related time and costs of implementing such transactions; integrating operations as part of these transactions; and possible failures to achieve expected gains, revenue growth and/or expense savings from such transactions.
- Costs, fines, penalties and other effects of legal and administrative proceedings, settlements, investigations, claims, including, but not limited to, such matters involving compliance with federal and state laws and interpretations of these laws.

The 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 commodity prices, interest rates, and counter-party credit. These financial exposures are monitored and managed by the Company as an integral part of its overall risk management program. The Company's risk management program includes, among other things, the 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 Utility Holdings, Inc. 2015 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 September 30, 2016, 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 September 30, 2016, 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 September 30, 2016, 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. OTHER INFORMATION

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. On March 12, 2015, certain claimants filed a Class Action Complaint against the Vectren Combined Plan and the Company in federal district court requesting that a class be certified and for various relief including that the Combined Plan be reformed and benefits thereunder be recalculated. The Company denied the allegations set forth in the Complaint and moved to dismiss the case. In April 2016, the court dismissed part of the Complaint but allowed the remaining claims to proceed. The court will not consider the class certification issue until after the summary judgment stage of the case. The parties are now engaged in the discovery process.

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 Utility Holdings 2015 Form 10-K and are therefore not presented herein.

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

Not Applicable

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

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 the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	VECTREN UTILITY HOLDINGS, INC. Registrant
November 10, 2016	/s/M. Susan Hardwick M. Susan Hardwick Executive Vice President and Chief Financial Officer (Signing on behalf of the registrant and as Principal Accounting & Financial Officer)