VECTREN UTILITY HOLDINGS INC
Form 10-Q
August 13, 2015

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2015
OR

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

For the transition period from __________________ to __________________

Commission file number: 1-16739

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

INDIANA	35-2104850
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

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

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

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

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

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

Large accelerated filer 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	July 31, 2015
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: M. Naveed Mughal Treasurer and Vice President, Investor Relations vvcir@vectren.com

Definitions

AFUDC: allowance for funds used during construction	MDth / MMDth: thousands / millions of dekatherms
DOT: Department of Transportation	MISO: Midcontinent Independent System Operator
EPA: Environmental Protection Agency	BTU / MMBTU: British thermal units/ millions of BTU
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	ASC: Accounting Standards Codification
IDEM: Indiana Department of Environmental Management	ASU: Accounting Standards Update
GCA: Gas Cost Adjustment	OUCC: Indiana Office of the Utility Consumer Counselor
IURC: Indiana Utility Regulatory Commission	XBRL: eXtensible Business Reporting Language
kV: Kilovolt	PUCO: Public Utilities Commission of Ohio

MCF / BCF: thousands / billions of cubic feet

GAAP: Generally Accepted Accounting Principles

Throughput: combined gas sales and gas transportation volumes

Table of Contents

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	June 30, 2015	December 31, 2014
ASSETS		
Current Assets		
Cash & cash equivalents	$6.7	$19.3
Accounts receivable - less reserves of $5.0 & $3.9, respectively	59.8	113.0
Accrued unbilled revenues	55.7	122.4
Inventories	104.0	113.2
Recoverable fuel & natural gas costs	—	9.8
Prepayments & other current assets	33.8	83.5
Total current assets	260.0	461.2
Utility Plant		
Original cost	5,887.1	5,718.7
Less: accumulated depreciation & amortization	2,352.3	2,279.7
Net utility plant	3,534.8	3,439.0
Investments in unconsolidated affiliates	0.2	0.2
Other investments	25.3	25.6
Nonutility plant - net	144.5	149.2
Goodwill - net	205.0	205.0
Regulatory assets	138.1	128.3
Other assets	36.4	19.6
TOTAL ASSETS	$4,344.3	$4,428.1

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

3

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

	June 30, 2015	December 31, 2014
LIABILITIES & SHAREHOLDER'S EQUITY		
Current Liabilities		
Accounts payable	$95.8	$180.4
Payables to other Vectren companies	47.4	28.6
Refundable fuel & natural gas costs	22.7	—
Accrued liabilities	125.4	122.3
Short-term borrowings	27.3	156.4
Current maturities of long-term debt	88.0	95.0
Total current liabilities	406.6	582.7
Long-Term Debt - Net of Current Maturities	1,164.5	1,162.3
Deferred Credits & Other Liabilities		
Deferred income taxes	708.5	685.1
Regulatory liabilities	424.3	410.3
Deferred credits & other liabilities	126.7	109.2
Total deferred credits & other liabilities	1,259.5	1,204.6
Commitments & Contingencies (Notes 8 - 11)		
Common Shareholder's Equity		
Common stock (no par value)	796.7	793.7
Retained earnings	717.0	684.8
Total common shareholder's equity	1,513.7	1,478.5
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$4,344.3	$4,428.1

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

4

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
OPERATING REVENUES				
Gas utility	$128.6	$132.4	$481.5	$576.0
Electric utility	147.8	152.0	301.7	315.0
Other	0.1	0.1	0.2	0.1
Total operating revenues	276.5	284.5	783.4	891.1
OPERATING EXPENSES				
Cost of gas sold	36.4	43.7	208.4	314.6
Cost of fuel & purchased power	47.0	48.1	97.0	105.1
Other operating	78.5	81.5	181.3	179.8
Depreciation & amortization	52.0	50.6	104.2	100.5
Taxes other than income taxes	12.1	12.5	31.2	32.6
Total operating expenses	226.0	236.4	622.1	732.6
OPERATING INCOME	50.5	48.1	161.3	158.5
Other income - net	4.3	3.7	9.2	7.6
Interest expense	16.4	16.7	33.0	33.4
INCOME BEFORE INCOME TAXES	38.4	35.1	137.5	132.7
Income taxes	14.0	12.2	50.1	48.5
NET INCOME	$24.4	$22.9	$87.4	$84.2

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

5

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

	Six Months Ended June 30, 2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$87.4	$84.2
Adjustments to reconcile net income to cash from operating activities:		
Depreciation & amortization	104.2	100.5
Deferred income taxes & investment tax credits	23.2	17.0
Expense portion of pension & postretirement periodic benefit cost	2.4	2.3
Provision for uncollectible accounts	4.1	2.3
Other non-cash items - net	3.4	1.5
Changes in working capital accounts:		
Accounts receivable & accrued unbilled revenue	115.8	102.8
Inventories	9.2	16.4
Recoverable/refundable fuel & natural gas costs	30.0	(22.7)
Prepayments & other current assets	50.6	4.1
Accounts payable, including to Vectren companies & affiliated companies	(89.0)	(88.9)
Accrued liabilities	5.6	(5.6)
Changes in noncurrent assets	(5.7)	5.8
Changes in noncurrent liabilities	(4.4)	(6.5)
Net cash provided by operating activities	336.8	213.2
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from additional capital contribution	3.0	3.2
Requirements for:		
Dividends to parent	(55.2)	(54.3)
Retirement of long-term debt	(5.0)	—
Net change in short-term borrowings	(129.1)	(24.9)
Net cash used in financing activities	(186.3)	(76.0)
CASH FLOWS FROM INVESTING ACTIVITIES		
Proceeds from other investing activities	0.1	0.1
Requirements for capital expenditures, excluding AFUDC equity	(163.2)	(141.0)
Net cash used in investing activities	(163.1)	(140.9)
Net change in cash & cash equivalents	(12.6)	(3.7)
Cash & cash equivalents at beginning of period	19.3	8.6
Cash & cash equivalents at end of period	$6.7	$4.9

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

6

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 583,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 144,000 electric customers and over 111,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to approximately 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 condensed consolidated financial statements and related notes should be read in conjunction with the Company's audited annual consolidated financial statements for the year ended December 31, 2014, filed with the Securities and Exchange Commission on March 5, 2015, 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 approximately $27 million was outstanding at June 30, 2015. The operating utility companies are also guarantors of Utility Holdings' unsecured senior notes with a par value of $875 million outstanding at June 30, 2015. 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 June 30, 2015 (in millions):

ASSETS	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Assets				
Cash & cash equivalents	$6.4	$0.3	$—	$6.7
Accounts receivable - less reserves	59.8	—	—	59.8
Intercompany receivables	62.6	130.2	(192.8)	—
Accrued unbilled revenues	55.7	—	—	55.7
Inventories	104.0	—	—	104.0
Prepayments & other current assets	23.5	29.3	(19.0)	33.8
Total current assets	312.0	159.8	(211.8)	260.0
Utility Plant				
Original cost	5,887.1	—	—	5,887.1
Less: accumulated depreciation & amortization	2,352.3	—	—	2,352.3
Net utility plant	3,534.8	—	—	3,534.8
Investments in consolidated subsidiaries	—	1,451.0	(1,451.0)	—
Notes receivable from consolidated subsidiaries	—	746.5	(746.5)	—
Investments in unconsolidated affiliates	0.2	—	—	0.2
Other investments	21.2	4.1	—	25.3
Nonutility plant - net	1.6	142.9	—	144.5
Goodwill - net	205.0	—	—	205.0
Regulatory assets	117.1	21.0	—	138.1
Other assets	42.9	1.5	(8.0)	36.4
TOTAL ASSETS	$4,234.8	$2,526.8	$(2,417.3)	$4,344.3

LIABILITIES & SHAREHOLDER'S EQUITY	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Liabilities				
Accounts payable	$92.0	$3.8	$—	$95.8
Intercompany payables	7.4	—	(7.4)	—
Payables to other Vectren companies	47.4	—	—	47.4
Refundable fuel & natural gas costs	22.7	—	—	22.7
Accrued liabilities	132.6	11.8	(19.0)	125.4
Short-term borrowings	—	27.3	—	27.3
Intercompany short-term borrowings	48.7	62.6	(111.3)	—
Current maturities of long-term debt	13.0	75.0	—	88.0
Current maturities of long-term debt due to VUHI	74.1	—	(74.1)	—
Total current liabilities	437.9	180.5	(211.8)	406.6
Long-Term Debt				
Long-term debt	364.7	799.8	—	1,164.5
Long-term debt due to VUHI	746.5	—	(746.5)	—
Total long-term debt - net	1,111.2	799.8	(746.5)	1,164.5
Deferred Credits & Other Liabilities				
Deferred income taxes	680.9	27.6	—	708.5
Regulatory liabilities	422.9	1.4	—	424.3
Deferred credits & other liabilities	130.9	3.8	(8.0)	126.7
Total deferred credits & other liabilities	1,234.7	32.8	(8.0)	1,259.5
Common Shareholder's Equity				
Common stock (no par value)	810.0	796.7	(810.0)	796.7

Retained earnings	641.0	717.0	(641.0)	717.0
Total common shareholder's equity	1,451.0	1,513.7	(1,451.0)	1,513.7
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$4,234.8	$2,526.8	$(2,417.3)	$4,344.3

8

Condensed Consolidating Balance Sheet as of December 31, 2014 (in millions):

ASSETS	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Assets				
Cash & cash equivalents	$6.9	$12.4	$—	$19.3
Accounts receivable - less reserves	113.0	—	—	113.0
Intercompany receivables	0.8	186.7	(187.5)	—
Accrued unbilled revenues	122.4	—	—	122.4
Inventories	113.2	—	—	113.2
Recoverable fuel & natural gas costs	9.8	—	—	9.8
Prepayments & other current assets	94.8	38.1	(49.4)	83.5
Total current assets	460.9	237.2	(236.9)	461.2
Utility Plant				
Original cost	5,718.7	—	—	5,718.7
Less: accumulated depreciation & amortization	2,279.7	—	—	2,279.7
Net utility plant	3,439.0	—	—	3,439.0
Investments in consolidated subsidiaries	—	1,416.9	(1,416.9)	—
Notes receivable from consolidated subsidiaries	—	746.5	(746.5)	—
Investments in unconsolidated affiliates	0.2	—	—	0.2
Other investments	21.3	4.3	—	25.6
Nonutility plant - net	1.8	147.4	—	149.2
Goodwill - net	205.0	—	—	205.0
Regulatory assets	106.7	21.6	—	128.3
Other assets	29.4	1.7	(11.5)	19.6
TOTAL ASSETS	$4,264.3	$2,575.6	$(2,411.8)	$4,428.1

LIABILITIES & SHAREHOLDER'S EQUITY	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Liabilities				
Accounts payable	$176.2	$4.2	$—	$180.4
Intercompany payables	15.6	0.8	(16.4)	—
Payables to other Vectren companies	28.6	—	—	28.6
Accrued liabilities	136.7	35.0	(49.4)	122.3
Short-term borrowings	—	156.4	—	156.4
Intercompany short-term borrowings	97.0	—	(97.0)	—
Current maturities of long-term debt	20.0	75.0	—	95.0
Current maturities of long-term debt due to VUHI	74.1	—	(74.1)	—
Total current liabilities	548.2	271.4	(236.9)	582.7
Long-Term Debt				
Long-term debt - net of current maturities & debt subject to tender	362.6	799.7	—	1,162.3
Long-term debt due to VUHI	746.5	—	(746.5)	—
Total long-term debt - net	1,109.1	799.7	(746.5)	1,162.3
Deferred Credits & Other Liabilities				
Deferred income taxes	665.8	19.3	—	685.1
Regulatory liabilities	408.8	1.5	—	410.3
Deferred credits & other liabilities	115.5	5.2	(11.5)	109.2
Total deferred credits & other liabilities	1,190.1	26.0	(11.5)	1,204.6
Common Shareholder's Equity				

Common stock (no par value)	806.9	793.7	(806.9)	793.7
Retained earnings	610.0	684.8	(610.0)	684.8
Total common shareholder's equity	1,416.9	1,478.5	(1,416.9)	1,478.5
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$4,264.3	$2,575.6	$(2,411.8)	$4,428.1

9

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

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	$128.6	$—	$—	$128.6
Electric utility	147.8	—	—	147.8
Other	—	10.2	(10.1)	0.1
Total operating revenues	276.4	10.2	(10.1)	276.5
OPERATING EXPENSES				
Cost of gas sold	36.4	—	—	36.4
Cost of fuel & purchased power	47.0	—	—	47.0
Other operating	87.9	—	(9.4)	78.5
Depreciation & amortization	45.5	6.4	0.1	52.0
Taxes other than income taxes	11.7	0.4	—	12.1
Total operating expenses	228.5	6.8	(9.3)	226.0
OPERATING INCOME	47.9	3.4	(0.8)	50.5
Other income - net	4.3	9.9	(9.9)	4.3
Interest expense	15.8	11.3	(10.7)	16.4
INCOME BEFORE INCOME TAXES	36.4	2.0	—	38.4
Income taxes	13.3	0.7	—	14.0
Equity in earnings of consolidated companies, net of tax	—	23.1	(23.1)	—
NET INCOME	$23.1	$24.4	$(23.1)	$24.4

Condensed Consolidating Statement of Income for the three months ended June 30, 2014 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	$132.4	$—	$—	$132.4
Electric utility	152.0	—	—	152.0
Other	—	9.5	(9.4)	0.1
Total operating revenues	284.4	9.5	(9.4)	284.5
OPERATING EXPENSES				
Cost of gas sold	43.7	—	—	43.7
Cost of fuel & purchased power	48.1	—	—	48.1
Other operating	90.3	—	(8.8)	81.5
Depreciation & amortization	44.6	5.9	0.1	50.6
Taxes other than income taxes	12.1	0.4	—	12.5
Total operating expenses	238.8	6.3	(8.7)	236.4
OPERATING INCOME	45.6	3.2	(0.7)	48.1
Other income - net	2.8	10.9	(10.0)	3.7
Interest expense	16.1	11.3	(10.7)	16.7
INCOME BEFORE INCOME TAXES	32.3	2.8	—	35.1
Income taxes	11.7	0.5	—	12.2
Equity in earnings of consolidated companies, net of tax	—	20.6	(20.6)	—
NET INCOME	$20.6	$22.9	$(20.6)	$22.9

10

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

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	$481.5	$—	$—	$481.5
Electric utility	301.7	—	—	301.7
Other	—	20.4	(20.2)	0.2
Total operating revenues	783.2	20.4	(20.2)	783.4
OPERATING EXPENSES				
Cost of gas sold	208.4	—	—	208.4
Cost of fuel & purchased power	97.0	—	—	97.0
Other operating	200.3	—	(19.0)	181.3
Depreciation & amortization	91.2	12.8	0.2	104.2
Taxes other than income taxes	30.3	0.9	—	31.2
Total operating expenses	627.2	13.7	(18.8)	622.1
OPERATING INCOME	156.0	6.7	(1.4)	161.3
Other income - net	8.4	20.7	(19.9)	9.2
Interest expense	31.7	22.6	(21.3)	33.0
INCOME BEFORE INCOME TAXES	132.7	4.8	—	137.5
Income taxes	50.1	—	—	50.1
Equity in earnings of consolidated companies, net of tax	—	82.6	(82.6)	—
NET INCOME	$82.6	$87.4	$(82.6)	$87.4

Condensed Consolidating Statement of Income for the six months ended June 30, 2014 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	$576.0	$—	$—	$576.0
Electric utility	315.0	—	—	315.0
Other	—	19.1	(19.0)	0.1
Total operating revenues	891.0	19.1	(19.0)	891.1
OPERATING EXPENSES				
Cost of gas sold	314.6	—	—	314.6
Cost of fuel & purchased power	105.1	—	—	105.1
Other operating	197.8	—	(18.0)	179.8
Depreciation & amortization	89.0	11.3	0.2	100.5
Taxes other than income taxes	31.7	0.8	0.1	32.6
Total operating expenses	738.2	12.1	(17.7)	732.6
OPERATING INCOME	152.8	7.0	(1.3)	158.5
Other income - net	5.8	21.6	(19.8)	7.6
Interest expense	31.9	22.6	(21.1)	33.4
INCOME BEFORE INCOME TAXES	126.7	6.0	—	132.7
Income taxes	48.5	—	—	48.5
Equity in earnings of consolidated companies, net of tax	—	78.2	(78.2)	—
NET INCOME	$78.2	$84.2	$(78.2)	$84.2

11

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

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH PROVIDED BY OPERATING ACTIVITIES	$317.7	$19.1	$—	$336.8
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from				
Additional capital contribution from parent	3.0	3.0	(3.0)	3.0
Requirements for:				
Dividends to parent	(51.6)	(55.2)	51.6	(55.2)
Retirement of long term debt	(5.0)	—	—	(5.0)
Net change in intercompany short-term borrowings	(48.2)	62.6	(14.4)	—
Net change in short-term borrowings	—	(129.1)	—	(129.1)
Net cash used in financing activities	(101.8)	(118.7)	34.2	(186.3)
CASH FLOWS FROM INVESTING ACTIVITIES				
Proceeds from:				
Consolidated subsidiary distributions	—	51.6	(51.6)	—
Other investing activities	—	0.1	—	0.1
Requirements for:				
Capital expenditures, excluding AFUDC equity	(153.8)	(9.4)	—	(163.2)
Consolidated subsidiary investments	—	(3.0)	3.0	—
Net change in short-term intercompany notes receivable	(62.6)	48.2	14.4	—
Net cash used in investing activities	(216.4)	87.5	(34.2)	(163.1)
Net change in cash & cash equivalents	(0.5)	(12.1)	—	(12.6)
Cash & cash equivalents at beginning of period	6.9	12.4	—	19.3
Cash & cash equivalents at end of period	$6.4	$0.3	$—	$6.7

Condensed Consolidating Statement of Cash Flows for the six months ended June 30, 2014 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH PROVIDED BY OPERATING ACTIVITIES	$181.9	$31.3	$—	$213.2
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from:				
Long-term debt, net of issuance costs	124.2	—	(124.2)	—
Additional capital contribution from parent	3.2	3.2	(3.2)	3.2
Requirements for:				
Dividends to parent	(50.8)	(54.3)	50.8	(54.3)
Net change in intercompany short-term borrowings	(49.2)	87.8	(38.6)	—
Net change in short-term borrowings	—	(24.9)	—	(24.9)
Net cash used in financing activities	27.4	11.8	(115.2)	(76.0)
CASH FLOWS FROM INVESTING ACTIVITIES				
Proceeds from:				
Consolidated subsidiary distributions	—	50.8	(50.8)	—
Other investing activities	—	0.1	—	0.1
Requirements for:				
Capital expenditures, excluding AFUDC equity	(126.8)	(14.2)	—	(141.0)

Consolidated subsidiary investments	—	(3.2)	3.2	—
Net change in long-term intercompany notes receivable	—	(124.2)	124.2	—
Net change in short-term intercompany notes receivable	(87.8)	49.2	38.6	—
Net cash used in investing activities	(214.6)	(41.5)	115.2	(140.9)
Net change in cash & cash equivalents	(5.3)	1.6	—	(3.7)
Cash & cash equivalents at beginning of period	8.2	0.4	—	8.6
Cash & cash equivalents at end of period	$2.9	$2.0	$—	$4.9

12

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 $5.4 million and $5.5 million in the three months ended June 30, 2015 and 2014, respectively. For the six months ended June 30, 2015 and 2014, these taxes totaled $17.1 million and $18.4 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 June 30, 2015 and December 31, 2014, the Company has accruals related to utility and nonutility plant purchases totaling approximately $21.3 million and $19.0 million, respectively.

6. Transactions with Other Vectren Companies and Affiliates

Vectren Fuels, Inc. (Vectren Fuels)
On August 29, 2014, Vectren closed on a transaction to sell its wholly owned coal mining subsidiary, Vectren Fuels, to Sunrise Coal, LLC (Sunrise), an Indiana-based wholly-owned subsidiary of Hallador Energy Company. Prior to the sale, SIGECO purchased coal used for electric generation from Vectren Fuels. The Company purchased $37.8 million and $68.6 million for the three and six months ended June 30, 2014, respectively. After the exit of the coal mining business by Vectren, Sunrise has assumed Vectren Fuels' supply contracts and has also negotiated new contracts for similar quality coal that will result in the Company purchasing most of its coal supply from Sunrise.

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 $31.6 million and $22.0 million for the three months ended June 30, 2015 and 2014, respectively, and for the six months ended June 30, 2015 and 2014 totaled $49.3 million and $33.4 million, respectively. Amounts owed to VISCO at June 30, 2015 and December 31, 2014 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 June 30, 2015 and 2014, Utility Holdings received corporate allocations totaling $11.9 million and $14.6 million, respectively. For the six months ending June 30, 2015 and 2014, Utility Holdings received corporate allocations totaling $27.5 million and $29.3 million, respectively.

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. Financing Activities

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

Utility Holdings Debt Transactions
On June 11, 2015, Vectren Utility Holdings entered into a private placement Note Purchase Agreement pursuant to which institutional investors have agreed to purchase the following tranches of notes: (i) $25 million of 3.90% Guaranteed Senior Notes, Series A, due December 15, 2035, (ii) $135 million of 4.36% Guaranteed Senior Notes, Series B, due December, 15,

13

2045, and (iii) $40 million of 4.51% Guaranteed Senior Notes, Series C, due December 15, 2055. The notes will be unconditionally guaranteed by Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company and Vectren Energy Delivery of Ohio, Inc. Subject to the satisfaction of customary conditions precedent, the financing is scheduled to close on or about December 15, 2015.

8. Commitments & Contingencies

Commitments

The Company has both firm and non-firm commitments to purchase natural gas, electricity, and coal as well as certain transportation and storage rights. Costs arising from these commitments, while significant, are pass-through costs, generally collected dollar-for-dollar from retail customers through regulator-approved cost recovery mechanisms.

Legal & Regulatory Proceedings

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

9. Gas Rate & Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement

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

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

In April 2013, Indiana Senate Bill 560 (Senate Bill 560) was signed into Indiana law. This legislation supplements Senate Bill 251 described above, and provides for cost recovery outside of a base rate proceeding for projects that either improve electric and gas system reliability and safety or are economic development projects that provide rural areas with access to gas service. Provisions of the legislation require that, among other things, requests for recovery include a seven-year project plan. Once the plan is approved by the IURC, 80 percent of such costs are eligible for current recovery using a periodic rate adjustment mechanism. Recoverable costs include a return on the investment that reflects the current capital structure and associated costs, with the exception of the rate of return on equity, which remains fixed at the rate determined in the Company's last rate case. Recoverable costs also include recovery of depreciation and other operating expenses. The remaining 20 percent of project costs is deferred and recovered in the utility’s next general rate case, which must be filed before the expiration of the seven year plan. The adjustment mechanism is capped at an annual increase in retail revenues of no more than two percent.

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

Indiana Recovery and Deferral Mechanisms
The Company's Indiana natural gas utilities received Orders in 2008 and 2007 associated with the most recent base rate cases. These Orders authorized the deferral of financial impacts associated with bare steel and cast iron replacement activities. The Orders provide for the deferral of depreciation and post in service carrying costs on qualifying projects totaling $20 million annually at Indiana Gas and $3 million annually at SIGECO. The debt-related post-in-service carrying costs are recognized in the Condensed Consolidated Statements of Income currently. The recording of post-in-service carrying costs and depreciation deferral is limited by individual qualifying projects to three years after being placed into service at SIGECO and four years after being placed into service at Indiana Gas. At June 30, 2015 and December 31, 2014, the Company has regulatory assets totaling $18.3 million and $16.4 million, respectively, associated with the deferral of depreciation and debt-related post-in-service carrying cost activities. Beginning in 2014, all bare steel and cast iron replacement activities are now part of the Company’s seven-year capital investment plan filed pursuant to Senate Bill 251, discussed further below.

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

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

On January 14, 2015, the IURC issued an Order approving the Company’s initial request for recovery of the revenue requirement through June 30, 2014 as part of its approved seven-year plan. As the next step of the recovery process, as outlined in the legislation, this Order initiates the rates and charges necessary to begin cash recovery of 80 percent of the revenue requirement, with the remaining 20 percent deferred for recovery in the Company's next rate cases. Also, consistent with the guidelines set forth in the original August 2014 Order, the IURC approved the Company’s update to its seven-year plan, to reflect changes to project prioritization as a result of both additional risk modeling and cost fluctuations. The updated plan reflects capital expenditures of approximately $900 million, an increase of $35 million from the previous plan and is inclusive of an estimated $30 million of economic development related expenditures, over the seven-year period beginning in 2014. The plan also includes approximately $15 million of annual operating costs associated with federal pipeline safety rules.
In April 2015, a group of industrial customers intervened as part of the pending appeal of the Company's Order referenced above, asking the Court of Appeals in light of a court decision related to another utility's seven-year plan, to consider whether the Company had failed to provide sufficient detail regarding its planned projects after year one of the plan. In the June 2015 decision, the Indiana Court of Appeals denied this request given that this issue was not raised during the Company's case or on appeal during the briefing period. As a result, the Company's Order approving its plan is final.

On April 1, 2015, the Company filed its second request for recovery of the revenue requirement associated with capital investment and applicable operating costs through December 31, 2014. On June 1, 2015, the Company amended its case to delay the recovery of a portion of the investment associated with the Senate Bill 560 approved investment made from July 2014 to December 2014, until its next filing in October 2015. The Company has offered to provide additional detail related to its seven-year plan in its update to be filed October 1, 2015. On July 22, 2015, the IURC issued an Order, approving the recovery of these investments consistent with the Company's proposal, with modification, specifically to the rate of return applicable to the Senate Bill 251 compliance component. The IURC found that the overall rate of return to be applied to the investment in determining the revenue requirement is to be updated with each filing, reflecting the current capital structure and associated costs, with the exception of the rate of return on equity, which remains fixed at the rate determined in the Company's last base rate case. This IURC interpretation of the overall rate of return to be used is the same as that already in place for the Senate Bill 560 component.

Ohio Recovery and Deferral Mechanisms
The PUCO Order approving the Company's 2009 base rate case in the Ohio service territory authorized a distribution replacement rider (DRR). The DRR's primary purpose is recovery of investments in utility plant and related operating expenses associated with replacing bare steel and cast iron pipelines and certain other infrastructure. This rider is updated annually for qualifying capital expenditures and allows for a return to be earned on those capital expenditures based on the rate of return approved in the 2009 base rate case. In addition, deferral of depreciation and the ability to accrue debt-related post-in-service carrying costs is also allowed until the related capital expenditures are included in the DRR. The Order also initially established a prospective bill impact evaluation on the annual deferrals. To date, the Company has made capital investments under this rider totaling $167.2 million. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $15.6 million and $13.1 million at June 30, 2015 and December 31, 2014, respectively. Due to the expiration of the initial five-year term for the DRR in early 2014, the Company filed a request in August 2013 to extend and expand the DRR. On February 19, 2014, the PUCO issued an Order approving a Stipulation entered into by the PUCO Staff and the Company which provided for the extension of the DRR for the recovery of costs incurred through 2017 and expanded the types of investment covered by the DRR to include recovery of other infrastructure investments. The Order limits the resulting DRR fixed charge per month for residential and small general service customers to specific graduated levels over the next five years. The Company's five-year capital expenditure plan related to these infrastructure investments for calendar years 2013 through 2017 totals approximately $200 million. The capital expenditure plan is subject to the graduated caps on the fixed DRR monthly charge applicable to residential and small general service customers approved in the Order however, is not expected to exceed those caps. In addition, the Order approved the Company's commitment that the DRR can only be further extended as part of a base rate case. On May 1, 2015, the Company filed its annual request to adjust the DRR for recovery of costs incurred through December 31, 2014. A procedural schedule has been set in this proceeding, and the Company expects an order by September 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 file a general rate case for the inclusion in rate base of the above costs near the expiration of the DRR. As such, the bill impact limits discussed below are not expected to be reached given the Company's capital expenditure plan during the remaining three-year time frame.

The PUCO has also issued Orders approving the Company's filings under Ohio House Bill 95. These Orders approve deferral of the Company’s Ohio capital expenditure program for items not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. Ohio House Bill 95 Orders also have established a prospective bill impact evaluation on the cumulative deferrals, limiting the total deferrals at a level which would equal $1.50 per residential and small general service customer per month. As of June 30, 2015, the Company's deferrals have not reached this bill impact cap. In addition, the Orders approved the Company's proposal that subsequent requests for accounting authority will be filed annually in April. The Company submitted its most recent annual filing on April 30, 2015, which covers the Company’s capital expenditure program through calendar year 2015.

Other Regulatory Matters

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

the OUCC modified its position in testimony filed on November 5, 2014, and suggested a reduced disallowance of $3 million. The IURC moved this specific issue to a sub-docket proceeding. On April 1, 2015, a stipulation and settlement agreement between the Company, the OUCC, and the Company’s supply administrator was filed in this proceeding. The IURC issued an Order on June 10, 2015 which approved the stipulation and settlement agreement, which resulted in recovery of approximately $1.4 million of the disputed amount via the Company’s GCA mechanism, with the remaining $1.6 million received from the gas supply administrator.

Indiana Gas & SIGECO Gas Decoupling Extension Filing
On August 18, 2011, the IURC issued an Order granting the extension of the current decoupling mechanism in place at both Indiana gas companies and recovery of new conservation program costs through December 2015. The Companies have reached an agreement in principle with the OUCC to extend the decoupling mechanism through 2020. The settlement was filed for approval on March 1, 2015. The settlement was unopposed and a hearing was held in May 2015. The Company expects an order later in 2015.

10. Electric Rate & Regulatory Matters

SIGECO Electric Environmental Compliance Filing
On January 28, 2015, the IURC issued an Order approving the Company's request for approval of capital investments on its coal-fired generation units to comply with new EPA mandates related to mercury and air toxin standards effective in 2015 and to address an outstanding Notice of Violation (NOV) from the EPA. As of June 30, 2015, approximately $30 million has been spent on equipment to control mercury in both air and water emissions, and $21 million to address the issues raised in the NOV proceeding on the increase in sulfur trioxide emissions. The total investment is estimated to be between $75 and $85 million. The Order approved the Company's request for deferred accounting treatment, as supported by provisions under Indiana Senate Bill 29 (Senate Bill 29) and Senate Bill 251. The accounting treatment includes the deferral of depreciation and property tax expense related to these investments, accrual of post-in-service carrying costs, and deferral of incremental operating expenses related to compliance with these standards. The initial phase of the projects went into service in 2014, with the remaining investment expected to occur in 2015 and 2016. As of June 30, 2015, the Company has approximately $1.4 million deferred related to depreciation, property tax, and operating expense, and $0.5 million deferred related to post-in-service carrying costs.

In March 2015, the Company was notified that certain parties had filed a Notice of Appeal with the Indiana Court of Appeals in response to the IURC's Order. In June 2015, Joint Appellants' Citizens Action Coalition of Indiana, Inc., Sierra Club, Inc., and Valley Watch, Inc. filed a brief which challenged the sufficiency of the findings in the IURC's January Order approving the Company's investments and proposed accounting treatment. The Company believes the IURC's Order satisfies applicable legal standards and filed its response on August 12, 2015. The Court is expected to decide on these issues later this year.

Coal Procurement Procedures
Entering 2014, SIGECO had in place staggered term coal contracts with Vectren Fuels, previously Vectren's wholly owned coal mining subsidiary, and one other supplier to provide supply for its generating units. During 2014, SIGECO entered into separate negotiations with Vectren Fuels and Sunrise Coal to modify its existing contracts as well as enter into new long-term contracts in order to secure its supply of coal with specifications that support its compliance with the Mercury and Air Toxins Rule. Subsequent to the sale of Vectren Fuels to Sunrise Coal in August 2014, all such contracts have been assigned to Sunrise Coal. Those contracts were submitted to the IURC for review as part of the 2014 annual sub docket proceeding. In December 2014, the IURC determined that the terms of the coal contracts were reasonable. The annual sub docket proceeding is no longer required.

On December 5, 2011 within the quarterly FAC filing, SIGECO submitted a joint proposal with the OUCC to reduce its fuel costs billed to customers by accelerating into 2012 the impact of lower cost coal under new term contracts effective after 2012. The cost difference was deferred to a regulatory asset and is being recovered over a six year period without interest beginning in 2014. The IURC approved this proposal on January 25, 2012, with the reduction to customer's rates effective February 1, 2012. The total balance deferred for recovery through the Company's FAC, which began February 2014, was $42.4 million, of which $31.8 million remains as of June 30, 2015.

SIGECO Electric Demand Side Management (DSM) Program Filing

On August 31, 2011 the IURC issued an Order approving an initial three-year DSM plan in the SIGECO electric service territory that complied with the IURC’s energy saving targets. Consistent with the Company’s proposal, the Order approved, among other items, the following: 1) recovery of costs associated with implementing the DSM Plan; 2) the recovery of a performance incentive mechanism based on measured savings related to certain DSM programs; 3) lost margin recovery associated with the implementation of DSM programs for large customers; and 4) deferral of lost margin up to $3 million in 2012 and $1 million in

2011 associated with small customer DSM programs for subsequent recovery under a tracking mechanism to be proposed by the Company. On June 20, 2012, the IURC issued an Order approving a small customer lost margin recovery mechanism, inclusive of all previous deferrals. This mechanism is an alternative to the electric decoupling proposal that was denied by the IURC in the Company's last base rate proceeding. For the six months ended June 30, 2015 and 2014, the Company recognized Electric utility revenue of $4.8 million and $4.4 million, respectively, associated with this approved lost margin recovery mechanism.

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

On May 6, 2015, Indiana's governor signed Indiana Senate Bill 412 into law requiring electricity suppliers to create and submit energy efficiency plans to the IURC at least one time every three years. Senate Bill 412 also supports the recovery of all program costs, including lost revenues and financial incentives associated with those plans and approved by the IURC. The Company made its first filing pursuant to this bill in June 2015, which proposed energy efficiency programs for calendar years 2016 and 2017. As defined within the procedural schedule set August 6, 2015, the OUCC and other stakeholders will file testimony in October 2015 and a hearing will be held November 13, 2015.

FERC Return on Equity (ROE) Complaint

On November 12, 2013, certain parties representing a group of industrial customers filed a joint complaint with the FERC under Section 206 of the Federal Power Act against MISO and various MISO transmission owners, including SIGECO. The joint parties seek to reduce the 12.38 percent return on equity used in the MISO transmission owners’ rates, including SIGECO’s formula transmission rates, to 9.15 percent, and to set a capital structure in which the equity component does not exceed 50 percent. The MISO transmission owners filed their response to the complaint on January 6, 2014, opposing any change to the return. As of June 30, 2015, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $141.9 million at June 30, 2015.

This joint complaint is similar to a complaint against the New England Transmission Owners (NETO) filed in September 2011, which requested that the 11.14 percent incentive return granted on qualifying investments in NETO be lowered. On October 16, 2014, the FERC issued an Order in the NETO case approving a 10.57 percent return on equity and a methodology set out in its June 19, 2014 decision.

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

Separately, on January 6, 2015, the FERC approved a MISO transmission owner joint request for an adder to the approved ROE. Under FERC regulations, transmission owners that are part of a Regional Transmission Organization (RTO) such as MISO are authorized to earn an incentive of 50 basis points above the FERC approved ROE. The FERC deferred the implementation of this adder until the pending complaint is resolved. Once the FERC sets a new

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

11. Environmental Matters

Indiana Senate Bill 251

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

Air Quality

Cross-State Air Pollution Rule

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

Mercury and Air Toxics (MATS) Rule

On December 21, 2011, the EPA finalized the utility MATS Rule. The MATS Rule sets emission limits for hazardous air pollutants for existing and new coal-fired power plants and identifies the following broad categories of hazardous air
pollutants: mercury, non-mercury hazardous air pollutants (primarily arsenic, chromium, cobalt, and selenium), and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride). The rule imposes mercury emission limits for two sub-categories of coal and proposed surrogate limits for non-mercury and acid gas hazardous air pollutants. Reductions are to be achieved within three years of publication of the final rule in the Federal Register. MATS compliance was required to commence April 16, 2015, and the Company is in full compliance with all requirements of MATS.

Legal challenges to the MATS Rule continue. 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 that the EPA appropriately based its decision to list coal and oil fired generation units as a source of the pollutants at issue solely on those pollutants' impact on public health. On June 29, 2015 the U.S. Supreme Court reversed the appellate court decision on the basis of the EPA's failure to consider costs before determining whether it was appropriate and necessary to regulate steam electric generating units under Section 112 of the Clean Air Act. The Court did not vacate the rule, but remanded the MATS rule back to the appellate court for further proceedings consistent with the opinion. The parties to the litigation are expected to be asked by the appellate court for briefing as to whether the court should vacate the rule, or leave it in place while the EPA supplements the rulemaking record pursuant to the Supreme Court opinion. Vectren continues to operate in full compliance with the MATS rule during the pendency of the appellate court remand which could take several months.

Notice of Violation for A.B. Brown Power Plant

The Company received a NOV from the EPA in November 2011 pertaining to its A.B. Brown generating station. The NOV asserts that when the facility was equipped with Selective Catalytic Reduction (SCR) systems, the correct permits were not obtained or the best available control technology to control incidental sulfuric acid mist was not installed. The Company reached a settlement in principle with the EPA to resolve the NOV. That settlement was contemplated in the plan filed and approved by the IURC on January 28, 2015 in the SIGECO Electric Environmental Compliance Filing.

Ozone NAAQS

On November 26, 2014, the EPA proposed to tighten the current National Ambient Air Quality Standard (NAAQS) for ozone from the current standard of 75 parts per billion (ppb) to a level with the range of 65 to 70 ppb. The EPA has stated that it intends to finalize the rule by October 2015. Upon finalization, the EPA will then determine whether a particular region is in attainment with the new standard. While it is possible that counties in southwest Indiana could be declared in non-attainment with the new standard, and thus may have an effect on future economic development activities in the Company's service territory, the Company does not anticipate any significant compliance cost impacts from the determination given its previous investment in SCR technology for NOx control on its units.

Water

Section 316(b) of the Clean Water Act requires that generating facilities use the “best technology available” (BTA) to minimize adverse environmental impacts on a body of water. More specifically, Section 316(b) is concerned with impingement and entrainment of aquatic species in once-through cooling water intake structures used at electric generating facilities. A final rule was issued by the EPA on May 19, 2014. The final rule does not mandate cooling water tower retrofits but requires a state level case-by-case assessment of BTA for each facility. The final rule lists seven presumptive technologies which would qualify as BTA. These technologies range from intake screen modifications to cooling water tower retrofits. Ecological and technology assessment studies must be completed prior to determining BTA for the Company’s facilities. To comply, the Company believes that capital investments will likely be in the range of $4 million to $8 million. Costs for compliance with these final regulations should qualify as federally mandated regulatory requirements and be recoverable under Indiana Senate Bill 251 referenced above.

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

Conclusions Regarding Air and Water Regulations

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

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

As noted previously, on January 28, 2015, the IURC issued an Order approving the Company’s request for approval of capital investments on its coal-fired generation units to comply with new EPA mandates related to mercury and air toxin standards effective in 2015 and to address an outstanding NOV from the EPA. The total investment is estimated to be between $75 and $85 million, roughly half of which will be made to control mercury in both air and water emissions, and the remaining investment will be made to address the issues raised in the NOV proceeding on the increase in sulfur trioxide emissions.

Coal Ash Waste Disposal & Ash Ponds

In December 2014 the EPA released its final Coal Combustion Residuals (CCR) rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). On April 17, 2015, the final rule was published in the Federal Register. The final rule allows beneficial reuse of ash and the Company will continue to reuse a majority of its ash. Legislation is currently being considered by Congress that would provide for enforcement of the federal program by states.

Under the final CCR rule, the Company is required to complete a series of integrity assessments and groundwater monitoring studies to determine whether one or more of the Company's ash ponds can continue in service, or whether a pond must be retrofitted with liners or closed and bottom ash handling conversions completed. The Company estimates capital expenditures to comply with the alternatives in the final rule could range from approximately $30 million for final capping and monitoring costs if the ponds are permitted to continue to operate to the end of the life of the generating units, to $100 million if existing ponds at both F.B. Culley and A.B. Brown generating stations are required to be closed and bottom ash conversions completed at each generating unit.

In the second quarter 2015, the Company recorded an asset retirement obligation (ARO) in the amount of $15.6 million which reflects the current present value of the costs to cap the existing ponds at the end of the life of the generating units. The estimated obligation is based on assumptions such as future ash levels, existing life of generating units, compliance assessments within the final rule at future dates, and costs for future construction services. These assumptions and estimations are subject to change in the future and could materially impact the amount of the estimated ARO. It is expected that any costs for compliance with these regulations should qualify as federally mandated regulatory requirements and be recoverable under Senate Bill 251 referenced above.

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

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

In July 2013, the President announced a Climate Action Plan, which called on the EPA to finalize the rule for new construction expeditiously and, by June 2015 finalize, New Source Performance Standards (NSPS) for GHG's for existing electric generating units which would apply to the Company's power plants. On June 2, 2014, the EPA proposed its rule for states to regulate CO2 emissions from existing electric generating units. The rule required states to adopt plans to reduce CO2 emissions by 30 percent from 2005 levels by 2030. The proposal set state-specific CO2 emission rate-based CO2 goals (measured in lb CO2/MWh) and guidelines for the development, submission and implementation of state plans to achieve the state goals. These state-specific goals were calculated based upon 2012 average emission rates aggregated for all fossil fuel-based units in the state. For Indiana, the proposal used a 2012 emission rate of 1,923 lb CO2/MWh, and set an interim goal of 1,607 lb CO2/MWh and a final emission goal of 1,531 lb CO2/MWh, or a 20 percent reduction in Indiana’s total CO2 emission rate, that must be met by 2030. Under this proposal, these CO2 emission rate goals do not apply directly to individual units or generating systems, but are instead state goals. As such, the state would be required to establish a framework that would guide how compliance would be met on a statewide basis. Indiana’s interim, or “phase in”, goal of 1,607 lb CO2/MWh must be met as averaged over a ten-year period (2020 - 2029) with progress toward this goal to be demonstrated for every two rolling calendar years starting in 2020, with the first report due in 2022. These individual state goals were based upon the application of four “building blocks” of emission rate improvements identified as the Best System of Emission Reduction, which defines

EPA’s authority under Section 111(d).

The Company timely filed comments to the Clean Power Plan (CPP) proposal on December 1, 2014. The State of Indiana also filed public comments, asking that the proposal be withdrawn. On July 31, 2014, litigation was filed by the state of Indiana and other parties challenging the rule prior to finalization by the EPA. In June 2015 these consolidated challenges were determined to be premature by the reviewing court, but the court’s decision did not preclude the parties from raising the arguments against the final rulemaking after EPA has published the final CPP in the Federal Register.

On August 3, 2015, the EPA released its final CPP which requires a 32 percent reduction in carbon emissions from 2005 levels. The original proposal in June 2014 called for a 30 percent reduction. The final CPP is significantly different in many respects from the June 2014 proposal. The EPA removed the energy efficiency block in the final rule and increased the assumption related to reliance upon renewables for compliance. In addition to the change in energy efficiency and renewables assumptions, the EPA also incorporated a new emission rate factor as a means of leveling the emission reduction requirements across the states. This resulted in the final emission rate reduction goal for Indiana of 1,242 lb CO_2 / MWh to be achieved by 2030, as compared to a goal of 1,531 lb CO_2/ MWh as proposed in June of 2014. Final state goals now fall within a narrower, lower range (between 771 lb CO_2/MWh and 1305 lb CO_2/MWh), with states having higher percentages of coal-fired generation receiving more stringent emission rate goals than those in the original proposal. The new rule also gives states an additional year to submit a state implementation plan, now September of 2018. Under the CPP, states have the flexibility to include energy efficiency and other measures should it choose to implement a state measures plan 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 glide path over the 2022-29 time period.

In the event that a state does not submit a state implementation plan (SIP), the EPA also released a proposed federal implementation plan (FIP), which would be imposed in those states without an approved SIP. The proposed FIP would apply an emission rate requirement directly on affected units. Under the proposed FIP the CO_2 emission rate limit for coal-fired units would start at 1671 lbs CO_2 / MWh in 2022 and decrease to a final emission rate cap of 1305 lbs CO_2 / MWh by 2030. While the FIP emission rate cap appears to be slightly less stringent, the cap would apply directly to affected units and these units would not have the benefit of averaging emission rates with rates from zero-carbon sources as in a SIP. Purchases of emission credits from zero-carbon sources can be made for compliance. Since the FIP has just been proposed, it will be subject to extensive public comments prior to finalization.

Indiana is the 5th largest carbon emitter in the nation in tons of CO_2 produced from electric generation. In 2013, Indiana's electric utilities generated 105.6 million tons of CO_2. The Company's share of that total was 6.3 million, or less than 6 percent. Since 2005, the Company's emissions of CO_2 have declined 23 percent (on a tonnage basis). These reductions have come from the retirement of F.B. Culley Unit 1, expiration of municipal contracts, electric conservation and the addition of renewable generation and the installation of more efficient dense pack turbine technology. With respect to renewable generation, in 2008 and 2009, the Company executed long-term purchase power commitments for a total of 80 MW of wind energy. The Company currently has approximately 4 percent of its electricity being provided by clean energy sources due to the long-term wind contracts and landfill gas investment. With respect to CO_2 emission rate, since 2005 the Company has lowered its CO_2 emission rate (as measured in lbs CO_2/MWh) from 1967 lbs CO_2/MWh to 1922 lbs CO_2/MWh, for a reduction of 3 percent. The Company's CO_2 emission rate of 1922 lbs/MWh is basically the same as the State's average CO_2 emission rate of 1923 lb CO_2/MWh.

Impact of Legislative Actions & Other Initiatives is Unknown

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 will undertake a detailed review of the requirements of the CPP and the proposed FIP and commence a review of potential compliance options for Vectren's affected units. In 2016 the Company will file its next integrated resource plan that will model compliance assumptions and costs and evaluate possible compliance alternatives. The Company will also continue to remain engaged with the State of Indiana to assess the final rule and to develop a plan that is the least cost to its customers. Costs to purchase allowances that cap GHG emissions or expenditures made to control emissions or lower carbon emission rates should be considered a federally mandated cost of providing electricity, and as such, the Company believes such costs and expenditures should be recoverable from customers through Senate Bill 251 as referenced above or Senate Bill 29, which was used by the Company to recover its initial pollution control investments.

Manufactured Gas Plants

In the past, the Company operated facilities to manufacture natural gas. Given the availability of natural gas transported by pipelines, these facilities have not been operated for many years. Under current environmental laws and regulations, those that owned or operated these facilities may now be required to take remedial action if certain contaminants are found above the regulatory thresholds.

In the Indiana Gas service territory, the existence, location, and certain general characteristics of 26 gas manufacturing and storage sites have been identified for which the Company may have some remedial responsibility. A remedial investigation/ feasibility study (RI/FS) was completed at one of the sites under an agreed upon order between Indiana Gas and the IDEM, and a Record of Decision was issued by the IDEM in January 2000. The remaining sites have been submitted to the IDEM's Voluntary Remediation Program (VRP). The Company has identified its involvement in five manufactured gas plant sites in SIGECO's service territory, all of which are currently enrolled in the IDEM's VRP. The Company is currently conducting some level of remedial activities, including groundwater monitoring at certain sites.

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

With respect to insurance coverage, Indiana Gas has received approximately $20.8 million from all known insurance carriers under insurance policies in effect when these plants were in operation. Likewise, SIGECO has settlement agreements with all known insurance carriers and has received to date approximately $14.3 million of the expected $15.8 million in insurance recoveries.

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company's utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of June 30, 2015 and December 31, 2014, approximately $3.4 million and $3.6 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

12. Fair Value Measurements

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

	June 30, 2015		December 31, 2014	
(In millions)	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	$1,252.5	$1,382.6	$1,257.3	$1,408.0
Short-term borrowings	27.3	27.3	156.4	156.4
Cash & cash equivalents	6.7	6.7	19.3	19.3

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

23

inherent difficulty of estimating interest rate and other market risks, the methods used to estimate fair value may not always be indicative of actual realizable value, and different methodologies could produce different fair value estimates at the reporting date.

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

13. Impact of Recently Issued Accounting Principles
Revenue Recognition Guidance
In May 2014, the FASB issued new accounting guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for GAAP and IFRS. The amendments in this guidance state that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This new guidance requires improved disclosures to help users of financial statements better understand the nature, amount, timing, and uncertainty of revenue that is recognized. On July 9, 2015, the FASB approved a one year deferral of the effective date to December 15, 2017 with early adoption permitted, but not before the original effective date of December 15, 2016. The Company is currently evaluating the standard to determine application date, transition method, and impact the standard will have on the financial statements.
Financial Reporting of Discontinued Operations
In April 2014, the FASB issued new accounting guidance on reporting discontinued operations and disclosures of disposals of a company or entity. The guidance changes the criteria for reporting discontinued operations and provides for enhanced disclosures in this area. Under the new guidance, only disposals representing a strategic shift in operations should be presented as discontinued operations. Those strategic shifts should have a major effect on the organization's operations and financial results. Additionally, the new guidance requires expanded disclosures about discontinued operations to provide more information about the assets, liabilities, income, and expenses of discontinued operations. The new guidance also requires disclosure of the pre-tax income attributable to a disposal of a significant part of an organization that does not qualify for discontinued operations reporting. This guidance is effective for fiscal years beginning on or after December 15, 2014, with early adoption permitted. The Company adopted this guidance on January 1, 2015. The adoption of this guidance had no impact on the Company's financial statements.

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

14. 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 to west central Ohio. The Electric Utility Services segment provides electric distribution services primarily to southwestern Indiana, and includes the Company’s power generating and wholesale power operations. Regulated operations supply natural gas and/or electricity to over one million customers. In total, the 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 June 30,		Six Months Ended June 30,	
(In millions)	2015	2014	2015	2014
Revenues				
Gas Utility Services	$128.6	$132.4	$481.5	$576.0
Electric Utility Services	147.8	152.0	301.7	315.0
Other Operations	10.2	9.5	20.4	19.1
Eliminations	(10.1)	(9.4)	(20.2)	(19.0)
Total Revenues	$276.5	$284.5	$783.4	$891.1
Profitability Measure - Net Income				
Gas Utility Services	$3.4	$0.7	$43.8	$39.0
Electric Utility Services	19.7	19.9	38.9	39.2
Other Operations	1.3	2.3	4.7	6.0
Total Net Income	$24.4	$22.9	$87.4	$84.2

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 583,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 144,000 electric customers and over 111,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to approximately 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 2014 annual report filed on Form 10-K.

Executive Summary of Consolidated Results of Operations

In the second quarter of 2015, Utility Holdings' earnings were $24.4 million, compared to $22.9 million in 2014. In the six months ended June 30, 2015, Utility Holdings earned $87.4 million, compared to $84.2 million in 2014. The quarter and year to date increases are largely driven by increases in gas utility margin from returns on the Indiana and Ohio infrastructure replacement programs, small customer growth, and large customer usage. Decreases in operating expenses related to performance-based compensation also favorably impacted earnings in both the quarter and year to date periods. Quarter and year to date results in 2015 were unfavorably impacted by a decrease in wholesale electric margin due primarily to lower market pricing compared to 2014 periods.

Gas Utility Services

During the second quarter of 2015, Gas Utility Services earned $3.4 million compared to earnings of $0.7 million in the second quarter of 2014. In the six months ended June 30, 2015, Gas Utility Services earnings were $43.8 million, compared to earnings of $39.0 million in 2014. Customer margin increased in 2015 from small customer growth, large customer usage, and the returns from the Indiana and Ohio infrastructure replacement programs. Overall, operating expenses were favorably impacted by a decrease in performance-based compensation compared to the 2014 periods.

Electric Utility Services

During the second quarter of 2015, Electric Utility Services' earnings were $19.7 million, compared to $19.9 million in the second quarter of 2014. Electric Utility Services earned $38.9 million year to date in 2015, compared to earnings of $39.2 million for the six months ended June 30, 2014. The decreases in the quarter and year to date periods are driven by the impact of weather on retail electric margin, which management estimates the unfavorable after tax impact to be approximately $0.5 million in the second quarter of 2015 and $1.1 million year to date, as compared to the 2014 periods. Quarter and year to date results were also unfavorably impacted by decreases in wholesale margin due primarily to lower market pricing. These decreases were offset somewhat by lower operating expenses in 2015 driven by the timing of power supply maintenance as well as increased performance-based compensation expense in 2014.

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 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 June 30,		Six Months Ended June 30,	
(In millions)	2015	2014	2015	2014
Gas utility revenues	$128.6	$132.4	$481.5	$576.0
Cost of gas sold	36.4	43.7	208.4	314.6
Total gas utility margin	$92.2	$88.7	$273.1	$261.4
Margin attributed to:				
Residential & commercial customers	$69.7	$67.5	$196.0	$190.7
Industrial customers	13.0	12.1	32.3	30.9
Other	2.5	2.8	5.9	6.4
Regulatory expense recovery mechanisms	7.0	6.3	38.9	33.4
Total gas utility margin	$92.2	$88.7	$273.1	$261.4
Sold & transported volumes in MMDth attributed to:				
Residential & commercial customers	10.7	12.0	72.9	77.6
Industrial customers	28.3	23.7	66.3	59.7
Total sold & transported volumes	39.0	35.7	139.2	137.3

Gas Utility margins were $92.2 million and $273.1 million for the three and six months ended June 30, 2015, and compared to 2014, increased $3.5 million quarter over quarter and $11.7 million year to date. Customer margin from small customer growth and large customer usage increased $1.1 million quarter over quarter and $1.9 million year to date compared to 2014. Additionally quarter over quarter margin was favorably impacted by increased return from infrastructure replacement programs in Indiana and Ohio of $2.2 million. Year to date margin was also favorably impacted by increased return from infrastructure replacement programs of $5.1 million. Year to date pass through margin increased $5.5 million in 2015 compared to 2014 due to increases in costs recovered through regulatory expense mechanisms.

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 June 30,		Six Months Ended June 30,	
(In millions)	2015	2014	2015	2014
Electric utility revenues	$147.8	$152.0	$301.7	$315.0
Cost of fuel & purchased power	47.0	48.1	97.0	105.1
Total electric utility margin	$100.8	$103.9	$204.7	$209.9
Margin attributed to:				
Residential & commercial customers	$62.8	$64.4	$126.5	$128.7
Industrial customers	28.4	27.9	55.2	53.9
Other	0.5	1.1	1.5	2.0
Regulatory expense recovery mechanisms	1.9	1.8	5.3	6.6
Subtotal: retail	$93.6	$95.2	$188.5	$191.2
Wholesale power & transmission system margin	7.2	8.7	16.2	18.7
Total electric utility margin	$100.8	$103.9	$204.7	$209.9
Electric volumes sold in GWh attributed to:				
Residential & commercial customers	643.1	658.4	1,345.7	1,377.5
Industrial customers	719.4	692.4	1,392.3	1,352.5
Other customers	4.8	4.9	10.9	10.9
Total retail volumes sold	1,367.3	1,355.7	2,748.9	2,740.9

Retail

Electric retail utility margins were $93.6 million and $188.5 million for the three and six months ended June 30, 2015, and compared to 2014, decreased by $1.6 million in the quarter and $2.7 million year to date. Electric results, which are not protected by weather normalizing mechanisms, reflect a $0.9 million decrease in small customer margin related to weather as annualized cooling degree days in the second quarter of 2015 were 107 percent of normal compared to 109 percent of normal in 2014. Similarly for the year to date period, electric results were unfavorably impacted by weather and resulted in a year to date decrease of $1.8 million in small customer margin. Small customer margin also decreased $0.6 million quarter over quarter and $0.8 million year to date compared to 2014 related to decreased electric volumes sold primarily related to continued customer conservation. Margin from regulatory expense recovery mechanisms decreased $1.3 million in the 2015 year to date period compared to 2014, driven primarily by a corresponding decrease in operating expenses associated with the electric conservation programs. Additionally, results reflect an increase in large customer usage of $0.6 million quarter over quarter and $1.3 million year to date compared to 2014, largely driven by large customer growth.

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 2017, in order to generate power to meet a significant portion of its ongoing power needs. Electric service is currently provided to SABIC by the Company under a long-term contract that expires in May of 2016. SABIC's historical peak electric usage has been approximately 120 megawatts (MW). The cogen facility is expected to provide 80 MW of capacity. Therefore, the Company will continue to provide all of SABIC's power requirements above the 80 MW capacity of the cogen, which is projected to be 40 MW. The Company also expects to provide back-up power, when required. The Company is actively working with SABIC on a transitional contractual arrangement. The Company continues to pursue and respond to economic development opportunities, among other things, as offsets to the margin lost from SABIC's cogeneration decision and as such, does not anticipate any significant impact on its future financial results.

Margin from Wholesale Electric Activities

The Company earns a return on electric transmission projects constructed by the Company in its service territory that meet the criteria of MISO's regional transmission expansion plans and also markets and sells its generating and transmission capacity to optimize the return on its owned assets. Substantially all off-system sales are generated in the MISO Day Ahead and Real Time markets when sales into the MISO in a given hour are greater than amounts purchased for native load. Further detail of MISO off-system margin and transmission system margin follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2015	2014	2015	2014
MISO Transmission system margin	$6.4	$6.6	$12.9	$12.7
MISO Off-system margin	0.8	2.1	3.3	6.0
Total wholesale margin	$7.2	$8.7	$16.2	$18.7

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms, and other transmission system operations, totaled $12.9 million and $12.7 million during the six months ended June 30, 2015 and 2014, respectively. As of June 30, 2015, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $141.9 million at June 30, 2015. These projects include an interstate 345 kV transmission line that connects the Company's A.B. Brown Generating Station to a generating station in Indiana owned by Duke Energy to the north and to a generating station in Kentucky owned by Big Rivers Electric Corporation to the south; a substation; and another transmission line. Although the allowed return is currently being challenged as discussed below in Rate and Regulatory Matters, once placed into service, these projects earn a FERC approved equity rate of return of 12.38 percent on the net plant balance. Operating expenses are also recovered. The Company has established a reserve pending the outcome of this complaint. The 345 kV project is the largest of these qualifying projects, with a cost of $106.8 million that earned the FERC approved equity rate of return, including while under construction.

For the six months ended June 30, 2015, margin from off-system sales was $3.3 million, compared to $6.0 million in 2014. The base rate changes implemented in May 2011 require that wholesale margin from off-system sales earned above or below $7.5 million per year be shared equally with customers. Results for the periods presented reflect the impact of that sharing as well as a decrease in volumes sold due to lower market pricing.

Operating Expenses

Other Operating
During the second quarter of 2015, other operating expenses were $78.5 million, a decrease of $3.0 million, compared to 2014. For the six months ended June 30, 2015, other operating expenses were $181.3 million, an increase of $1.5 million, compared to 2014. The increase in other operating costs for the year to date period is primarily due to increases in costs that are recovered directly in margin. Excluding these pass through costs, other operating expenses decreased $4.3 million in 2015, compared to the same period in 2014. Both quarter and year to date periods reflect decreased performance-based compensation expense, as well as lower operating expenses in 2015 due to the timing of power supply maintenance in 2014.

Depreciation & Amortization
In the second quarter of 2015, depreciation and amortization expense was $52.0 million compared to $50.6 million in 2014. For the six months ended June 30, 2015, depreciation and amortization expense was $104.2 million, which represents an increase of $3.7 million compared to 2014. Both quarter and year to date periods reflect increased plant placed in service.

Taxes Other Than Income Taxes
Taxes other than income taxes were $12.1 million for the second quarter of 2015, a decrease of $0.4 million compared to 2014. Year to date, taxes other than income taxes were $31.2 million compared to $32.6 million for the year to date period in 2014. The decrease in both the year to date and quarter periods is primarily due to decreased revenue taxes. These taxes are offset dollar-for-dollar with lower gas utility and electric utility revenues reflected in margin attributable to regulatory expense recovery mechanisms.

Other Income - Net

Other income-net reflects income of $4.3 million for the second quarter of 2015, an increase of $0.6 million, compared to 2014. Year to date, other income-net reflects income of $9.2 million compared to $7.6 million in 2014. The increase is primarily due to higher AFUDC driven by increased capital expenditures related to gas utility infrastructure replacement investments, as well as higher AFUDC rates.

Gas Rate & Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement

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

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

In April 2013, Indiana Senate Bill 560 (Senate Bill 560) was signed into Indiana law. This legislation supplements Senate Bill 251 described above, and provides for cost recovery outside of a base rate proceeding for projects that either improve electric and gas system reliability and safety or are economic development projects that provide rural areas with access to gas service. Provisions of the legislation require that, among other things, requests for recovery include a seven-year project plan. Once the plan is approved by the IURC, 80 percent of such costs are eligible for current recovery using a periodic rate adjustment mechanism. Recoverable costs include a return on the investment that reflects the current capital structure and associated costs, with the exception of the rate of return on equity, which remains fixed at the rate determined in the Company's last rate case. Recoverable costs also include recovery of depreciation and other operating expenses. The remaining 20 percent of project costs is deferred and recovered in the utility’s next general rate case, which must be filed before the expiration of the seven year plan. The adjustment mechanism is capped at an annual increase in retail revenues of no more than two percent.

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

Indiana Recovery and Deferral Mechanisms

The Company's Indiana natural gas utilities received Orders in 2008 and 2007 associated with the most recent base rate cases. These Orders authorized the deferral of financial impacts associated with bare steel and cast iron replacement activities. The Orders provide for the deferral of depreciation and post in service carrying costs on qualifying projects totaling $20 million annually at Indiana Gas and $3 million annually at SIGECO. The debt-related post-in-service carrying costs are recognized in the Condensed Consolidated Statements of Income currently. The recording of post-in-service carrying costs and depreciation deferral is limited by individual qualifying projects to three years after being placed into service at SIGECO and four years after being placed into service at Indiana Gas. At June 30, 2015 and December 31, 2014, the Company has regulatory assets totaling $18.3 million and $16.4 million, respectively, associated with the deferral of depreciation and debt-related post-in-service carrying cost activities. Beginning in 2014, all bare steel and cast iron replacement activities are now part of the Company’s seven-year capital investment plan filed pursuant to Senate Bill 251, discussed further below.

Requests for Recovery Under Indiana Regulatory Mechanisms

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

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

On January 14, 2015, the IURC issued an Order approving the Company’s initial request for recovery of the revenue requirement through June 30, 2014 as part of its approved seven-year plan. As the next step of the recovery process, as outlined in the legislation, this Order initiates the rates and charges necessary to begin cash recovery of 80 percent of the revenue requirement, with the remaining 20 percent deferred for recovery in the Company's next rate cases. Also, consistent with the guidelines set forth in the original August 2014 Order, the IURC approved the Company’s update to its seven-year plan, to reflect changes to project prioritization as a result of both additional risk modeling and cost fluctuations. The updated plan reflects capital expenditures of approximately $900 million, an increase of $35 million from the previous plan and is inclusive of an estimated $30 million of economic development related expenditures, over the seven-year period beginning in 2014. The plan also includes approximately $15 million of annual operating costs associated with federal pipeline safety rules.
In April 2015, a group of industrial customers intervened as part of the pending appeal of the Company's Order referenced above, asking the Court of Appeals in light of a court decision related to another utility's seven-year plan, to consider whether the Company had failed to provide sufficient detail regarding its planned projects after year one of the plan. In the June 2015 decision, the Indiana Court of Appeals denied this request given that this issue was not raised during the Company's case or on appeal during the briefing period. As a result, the Company's Order approving its plan is final.

On April 1, 2015, the Company filed its second request for recovery of the revenue requirement associated with capital investment and applicable operating costs through December 31, 2014. On June 1, 2015, the Company amended its case to delay the recovery of a portion of the investment associated with the Senate Bill 560 approved investment made from July 2014 to December 2014, until its next filing in October 2015. The Company has offered to provide additional detail related to its seven-year plan in its update to be filed October 1, 2015. On July 22, 2015, the IURC issued an Order, approving the recovery of these investments consistent with the Company's proposal, with modification, specifically to the rate of return applicable to the Senate Bill 251 compliance component. The IURC found that the overall rate of return to be applied to the investment in determining the revenue requirement is to be updated with each filing, reflecting the current capital structure and associated costs, with the exception of the rate of return on equity, which remains fixed at the rate determined in the Company's last base rate case. This IURC interpretation of the overall rate of return to be used is the same as that already in place for the Senate Bill 560 component.

Ohio Recovery and Deferral Mechanisms
The PUCO Order approving the Company's 2009 base rate case in the Ohio service territory authorized a distribution replacement rider (DRR). The DRR's primary purpose is recovery of investments in utility plant and related operating expenses associated with replacing bare steel and cast iron pipelines and certain other infrastructure. This rider is updated annually for qualifying capital expenditures and allows for a return to be earned on those capital expenditures based on the rate of return approved in the 2009 base rate case. In addition, deferral of depreciation and the ability to accrue debt-related post-in-service carrying costs is also allowed until the related capital expenditures are included in the DRR. The Order also initially established a prospective bill impact evaluation on the annual deferrals. To date, the Company has made capital investments under this rider totaling $167.2 million. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $15.6 million and $13.1 million at June 30, 2015 and December 31, 2014, respectively. Due to the expiration of the initial five-year term for the DRR in early 2014, the Company filed a request in August 2013 to extend and expand the DRR. On February 19, 2014, the PUCO issued an Order approving a Stipulation entered into by the PUCO Staff and the Company which provided for the extension of

the DRR for the recovery of costs incurred through 2017 and expanded the types of investment covered by the DRR to include recovery of other infrastructure investments. The Order limits the resulting DRR fixed charge per month for residential and small general service customers to specific graduated levels over the next five years. The Company's five-year capital expenditure plan related to these infrastructure investments for calendar years 2013 through 2017 totals approximately $200 million. The capital expenditure plan is subject to the graduated caps on the fixed DRR monthly charge applicable to residential and small general service customers approved in the Order however, is not expected to exceed those caps. In addition, the Order approved the Company's commitment that the DRR can only be further extended as part of a base rate case. On May 1, 2015, the Company filed its annual request to adjust the DRR for recovery of costs incurred through December 31, 2014. A procedural schedule has been set in this proceeding, and the Company expects an order by September 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 file a general rate case for the inclusion in rate base of the above costs near the expiration of the DRR. As such, the bill impact limits discussed below are not expected to be reached given the Company's capital expenditure plan during the remaining three-year time frame.

The PUCO has also issued Orders approving the Company's filings under Ohio House Bill 95. These Orders approve deferral of the Company’s Ohio capital expenditure program for items not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. Ohio House Bill 95 Orders also have established a prospective bill impact evaluation on the cumulative deferrals, limiting the total deferrals at a level which would equal $1.50 per residential and small general service customer per month. As of June 30, 2015, the Company's deferrals have not reached this bill impact cap. In addition, the Orders approved the Company's proposal that subsequent requests for accounting authority will be filed annually in April. The Company submitted its most recent annual filing on April 30, 2015, which covers the Company’s capital expenditure program through calendar year 2015.

Other Regulatory Matters

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

Indiana Gas & SIGECO Gas Decoupling Extension Filing
On August 18, 2011, the IURC issued an Order granting the extension of the current decoupling mechanism in place at both Indiana gas companies and recovery of new conservation program costs through December 2015. The Companies have reached an agreement in principle with the OUCC to extend the decoupling mechanism through 2020. The settlement was filed for approval on March 1, 2015. The settlement was unopposed and a hearing was held in May 2015. The Company expects an order later in 2015.

Electric Rate & Regulatory Matters

SIGECO Electric Environmental Compliance Filing
On January 28, 2015, the IURC issued an Order approving the Company’s request for approval of capital investments on its coal-fired generation units to comply with new EPA mandates related to mercury and air toxin standards effective in 2015 and to address an outstanding Notice of Violation (NOV) from the EPA. As of June 30, 2015, approximately $30 million has been spent on equipment to control mercury in both air and water emissions, and $21

million to address the issues raised in the NOV proceeding on the increase in sulfur trioxide emissions. The total investment is estimated to be between $75 and $85 million. The Order approved the Company’s request for deferred accounting treatment, as supported by provisions under Indiana Senate Bill 29 (Senate Bill 29) and Senate Bill 251. The accounting treatment includes the deferral of depreciation and property tax expense related to these investments, accrual of post-in-service carrying costs, and deferral of incremental operating expenses related to compliance with these standards. The initial phase of the projects went into service in 2014, with the remaining investment expected to occur in 2015 and 2016. As of June 30, 2015, the Company has approximately $1.4 million deferred related to depreciation, property tax, and operating expense, and $0.5 million deferred related to post-in-service carrying costs.

In March 2015, the Company was notified that certain parties had filed a Notice of Appeal with the Indiana Court of Appeals in response to the IURC's Order. In June 2015, Joint Appellants' Citizens Action Coalition of Indiana, Inc., Sierra Club, Inc., and Valley Watch, Inc. filed a brief which challenged the sufficiency of the findings in the IURC's January Order approving the Company's investments and proposed accounting treatment. The Company believes the IURC's Order satisfies applicable legal standards and filed its response on August 12, 2015. The Court is expected to decide on these issues later this year.

Coal Procurement Procedures

Entering 2014, SIGECO had in place staggered term coal contracts with Vectren Fuels, previously Vectren's wholly owned coal mining subsidiary, and one other supplier to provide supply for its generating units. During 2014, SIGECO entered into separate negotiations with Vectren Fuels and Sunrise Coal to modify its existing contracts as well as enter into new long-term contracts in order to secure its supply of coal with specifications that support its compliance with the Mercury and Air Toxins Rule. Subsequent to the sale of Vectren Fuels to Sunrise Coal in August 2014, all such contracts have been assigned to Sunrise Coal. Those contracts were submitted to the IURC for review as part of the 2014 annual sub docket proceeding. In December 2014, the IURC determined that the terms of the coal contracts were reasonable. The annual sub docket proceeding is no longer required.

On December 5, 2011 within the quarterly FAC filing, SIGECO submitted a joint proposal with the OUCC to reduce its fuel costs billed to customers by accelerating into 2012 the impact of lower cost coal under new term contracts effective after 2012. The cost difference was deferred to a regulatory asset and is being recovered over a six year period without interest beginning in 2014. The IURC approved this proposal on January 25, 2012, with the reduction to customer's rates effective February 1, 2012. The total balance deferred for recovery through the Company's FAC, which began February 2014, was $42.4 million, of which $31.8 million remains as of June 30, 2015.

SIGECO Electric Demand Side Management (DSM) Program Filing

On August 31, 2011 the IURC issued an Order approving an initial three-year DSM plan in the SIGECO electric service territory that complied with the IURC's energy saving targets. Consistent with the Company's proposal, the Order approved, among other items, the following: 1) recovery of costs associated with implementing the DSM Plan; 2) the recovery of a performance incentive mechanism based on measured savings related to certain DSM programs; 3) lost margin recovery associated with the implementation of DSM programs for large customers; and 4) deferral of lost margin up to $3 million in 2012 and $1 million in 2011 associated with small customer DSM programs for subsequent recovery under a tracking mechanism to be proposed by the Company. On June 20, 2012, the IURC issued an Order approving a small customer lost margin recovery mechanism, inclusive of all previous deferrals. This mechanism is an alternative to the electric decoupling proposal that was denied by the IURC in the Company's last base rate proceeding. For the six months ended June 30, 2015 and 2014, the Company recognized Electric utility revenue of $4.8 million and $4.4 million, respectively, associated with this approved lost margin recovery mechanism.

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

On May 6, 2015, Indiana's governor signed Indiana Senate Bill 412 into law requiring electricity suppliers to create and submit energy efficiency plans to the IURC at least one time every three years. Senate Bill 412 also supports the recovery of all program costs, including lost revenues and financial incentives associated with those plans and approved by the IURC. The Company made its first filing pursuant to this bill in June 2015, which proposed energy efficiency programs for calendar years

2016 and 2017. As defined within the procedural schedule set August 6, 2015, the OUCC and other stakeholders will file testimony in October 2015 and a hearing will be held November 13, 2015.

FERC Return on Equity (ROE) Complaint
On November 12, 2013, certain parties representing a group of industrial customers filed a joint complaint with the FERC under Section 206 of the Federal Power Act against MISO and various MISO transmission owners, including SIGECO. The joint parties seek to reduce the 12.38 percent return on equity used in the MISO transmission owners' rates, including SIGECO's formula transmission rates, to 9.15 percent, and to set a capital structure in which the equity component does not exceed 50 percent. The MISO transmission owners filed their response to the complaint on January 6, 2014, opposing any change to the return. As of June 30, 2015, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $141.9 million at June 30, 2015.

This joint complaint is similar to a complaint against the New England Transmission Owners (NETO) filed in September 2011, which requested that the 11.14 percent incentive return granted on qualifying investments in NETO be lowered. On October 16, 2014, the FERC issued an Order in the NETO case approving a 10.57 percent return on equity and a methodology set out in its June 19, 2014 decision.

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

Separately, on January 6, 2015, the FERC approved a MISO transmission owner joint request for an adder to the approved ROE. Under FERC regulations, transmission owners that are part of a Regional Transmission Organization (RTO) such as MISO are authorized to earn an incentive of 50 basis points above the FERC approved ROE. The FERC deferred the implementation of this adder until the pending complaint is resolved. Once the FERC sets a new ROE in the complaint case, this adder will be applied to that ROE, with retroactive billing to occur back to January 7, 2015.

Environmental Matters

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

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

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

Mercury and Air Toxics (MATS) Rule
On December 21, 2011, the EPA finalized the utility MATS Rule. The MATS Rule sets emission limits for hazardous air pollutants for existing and new coal-fired power plants and identifies the following broad categories of hazardous air
pollutants: mercury, non-mercury hazardous air pollutants (primarily arsenic, chromium, cobalt, and selenium), and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride). The rule imposes mercury emission limits for two sub-categories of coal and proposed surrogate limits for non-mercury and acid gas hazardous air pollutants. Reductions are to be achieved within three years of publication of the final rule in the Federal Register. MATS compliance was required to commence April 16, 2015, and the Company is in full compliance with all requirements of MATS.

Legal challenges to the MATS Rule continue. 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 that the EPA appropriately based its decision to list coal and oil fired generation units as a source of the pollutants at issue solely on those pollutants' impact on public health. On June 29, 2015 the U.S. Supreme Court reversed the appellate court decision on the basis of the EPA's failure to consider costs before determining whether it was appropriate and necessary to regulate steam electric generating units under Section 112 of the Clean Air Act. The Court did not vacate the rule, but remanded the MATS rule back to the appellate court for further proceedings consistent with the opinion. The parties to the litigation are expected to be asked by the appellate court for briefing as to whether the court should vacate the rule, or leave it in place while the EPA supplements the rulemaking record pursuant to the Supreme Court opinion. Vectren continues to operate in full compliance with the MATS rule during the pendency of the appellate court remand which could take several months.

Notice of Violation for A.B. Brown Power Plant
The Company received a NOV from the EPA in November 2011 pertaining to its A.B. Brown generating station. The NOV asserts that when the facility was equipped with Selective Catalytic Reduction (SCR) systems, the correct permits were not obtained or the best available control technology to control incidental sulfuric acid mist was not installed. The Company reached a settlement in principle with the EPA to resolve the NOV. That settlement was contemplated in the plan filed and approved by the IURC on January 28, 2015 in the SIGECO Electric Environmental Compliance Filing.

Ozone NAAQS
On November 26, 2014, the EPA proposed to tighten the current National Ambient Air Quality Standard (NAAQS) for ozone from the current standard of 75 parts per billion (ppb) to a level with the range of 65 to 70 ppb. The EPA has stated that it intends to finalize the rule by October 2015. Upon finalization, the EPA will then determine whether a particular region is in attainment with the new standard. While it is possible that counties in southwest Indiana could be declared in non-attainment with the new standard, and thus may have an effect on future economic development activities in the Company's service territory, the Company does not anticipate any significant compliance cost impacts from the determination given its previous investment in SCR technology for NOx control on its units.

Water
Section 316(b) of the Clean Water Act requires that generating facilities use the "best technology available" (BTA) to minimize adverse environmental impacts on a body of water. More specifically, Section 316(b) is concerned with impingement and entrainment of aquatic species in once-through cooling water intake structures used at electric generating facilities. A final rule was issued by the EPA on May 19, 2014. The final rule does not mandate cooling water tower retrofits but requires a state level case-by-case assessment of BTA for each facility. The final rule lists seven presumptive technologies which would qualify as BTA. These technologies range from intake screen modifications to cooling water tower retrofits. Ecological and technology assessment studies must be completed prior

to determining BTA for the Company’s facilities. To comply, the Company believes that capital investments will likely be in the range of $4 million to $8 million. Costs for compliance with these final regulations should qualify as federally mandated regulatory requirements and be recoverable under Indiana Senate Bill 251 referenced above.

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

Conclusions Regarding Air and Water Regulations

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

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

As noted previously, on January 28, 2015, the IURC issued an Order approving the Company's request for approval of capital investments on its coal-fired generation units to comply with new EPA mandates related to mercury and air toxin standards effective in 2015 and to address an outstanding NOV from the EPA. The total investment is estimated to be between $75 and $85 million, roughly half of which will be made to control mercury in both air and water emissions, and the remaining investment will be made to address the issues raised in the NOV proceeding on the increase in sulfur trioxide emissions.

Coal Ash Waste Disposal & Ash Ponds

In December 2014 the EPA released its final Coal Combustion Residuals (CCR) rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). On April 17, 2015, the final rule was published in the Federal Register. The final rule allows beneficial reuse of ash and the Company will continue to reuse a majority of its ash. Legislation is currently being considered by Congress that would provide for enforcement of the federal program by states.

Under the final CCR rule, the Company is required to complete a series of integrity assessments and groundwater monitoring studies to determine whether one or more of the Company's ash ponds can continue in service, or whether a pond must be retrofitted with liners or closed and bottom ash handling conversions completed. The Company estimates capital expenditures to comply with the alternatives in the final rule could range from approximately $30 million for final capping and monitoring costs if the ponds are permitted to continue to operate to the end of the life of the generating units, to $100 million if existing ponds at both F.B. Culley and A.B. Brown generating stations are required to be closed and bottom ash conversions completed at each generating unit.

In the second quarter 2015, the Company recorded an asset retirement obligation (ARO) in the amount of $15.6 million which reflects the current present value of the costs to cap the existing ponds at the end of the life of the generating units. The estimated obligation is based on assumptions such as future ash levels, existing life of generating units, compliance assessments within the final rule at future dates, and costs for future construction services. These assumptions and estimations are subject to change in the future and could materially impact the amount of the estimated ARO. It is expected that any costs for compliance with these regulations should qualify as federally mandated regulatory requirements and be recoverable under Senate Bill 251 referenced above.

Climate Change

As a wholly owned subsidiary of Vectren, 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 investment in advanced clean coal technology and support for research and development; and
- A strategy supporting alternative energy technologies and biofuels and continued increase in the domestic supply of natural gas and oil to reduce dependence on foreign oil.

Based on data made available through the Electronic Greenhouse Gas Reporting Tool (e-GRRT) maintained by the EPA, the Company’s direct CO2 emissions from its fossil fuel electric generation that report under the Acid Rain Program were less than one half of one percent of all emissions in the United States from similar sources. Emissions from other Company operations, including those from its natural gas distribution operations and the greenhouse gas emissions the Company is required to report on behalf of its end use customers, are similarly available through the EPA’s e-GRRT database and reporting tool.

Current Initiatives to Increase Conservation & Reduce Emissions
The Company is committed to a policy that reduces greenhouse gas emissions and conserves energy usage. Evidence of this commitment includes:

- Focusing the Company’s mission statement and purpose on corporate sustainability and the need to help customers conserve and manage energy costs. Vectren's annual sustainability report received C level certification by the Global Reporting Initiative. This certification creates shared value, demonstrates the Company's commitment to sustainability and denotes transparency in operations;
- Implementing conservation initiatives in the Company’s Indiana and Ohio gas utility service territories;
- Implementing conservation and demand side management initiatives in the electric service territory;
- Building a renewable energy portfolio to complement base load generation in advance of mandated renewable energy portfolio standards;
- Evaluating potential carbon requirements with regard to new generation, other fuel supply sources, and future environmental compliance plans;
- Reducing the Company’s carbon footprint by measures such as utilizing hybrid vehicles and optimizing generation efficiencies by utilizing dense pack technology; and
- Reducing methane emissions through continued replacement of bare steel and cast iron gas distribution pipeline

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

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

In July 2013, the President announced a Climate Action Plan, which called on the EPA to finalize the rule for new construction expeditiously and, by June 2015 finalize, New Source Performance Standards (NSPS) for GHG's for existing electric generating units which would apply to the Company's power plants. On June 2, 2014, the EPA proposed its rule for states to regulate CO2 emissions from existing electric generating units. The rule required states to adopt plans to reduce CO2 emissions by 30 percent from 2005 levels by 2030. The proposal set state-specific CO2 emission rate-based CO2 goals (measured in lb CO2/MWh) and guidelines for the development, submission and implementation of state plans to achieve the state goals. These state-specific goals were calculated based upon 2012 average emission rates aggregated for all fossil fuel-based units in the

37

state. For Indiana, the proposal used a 2012 emission rate of 1,923 lb CO_2/MWh, and set an interim goal of 1,607 lb CO_2/MWh and a final emission goal of 1,531 lb CO_2/MWh, or a 20 percent reduction in Indiana’s total CO_2 emission rate, that must be met by 2030. Under this proposal, these CO_2 emission rate goals do not apply directly to individual units or generating systems, but are instead state goals. As such, the state would be required to establish a framework that would guide how compliance would be met on a statewide basis. Indiana’s interim, or “phase in”, goal of 1,607 lb CO_2/MWh must be met as averaged over a ten-year period (2020 - 2029) with progress toward this goal to be demonstrated for every two rolling calendar years starting in 2020, with the first report due in 2022. These individual state goals were based upon the application of four “building blocks” of emission rate improvements identified as the Best System of Emission Reduction, which defines EPA’s authority under Section 111(d).

The Company timely filed comments to the Clean Power Plan (CPP) proposal on December 1, 2014. The State of Indiana also filed public comments, asking that the proposal be withdrawn. On July 31, 2014, litigation was filed by the state of Indiana and other parties challenging the rule prior to finalization by the EPA. In June 2015 these consolidated challenges were determined to be premature by the reviewing court, but the court’s decision did not preclude the parties from raising the arguments against the final rulemaking after EPA has published the final CPP in the Federal Register.

On August 3, 2015, the EPA released its final CPP which requires a 32 percent reduction in carbon emissions from 2005 levels. The original proposal in June 2014 called for a 30 percent reduction. The final CPP is significantly different in many respects from the June 2014 proposal. The EPA removed the energy efficiency block in the final rule and increased the assumption related to reliance upon renewables for compliance. In addition to the change in energy efficiency and renewables assumptions, the EPA also incorporated a new emission rate factor as a means of leveling the emission reduction requirements across the states. This resulted in the final emission rate reduction goal for Indiana of 1,242 lb CO_2 / MWh to be achieved by 2030, as compared to a goal of 1,531 lb CO_2/ MWh as proposed in June of 2014. Final state goals now fall within a narrower, lower range (between 771 lb CO_2/MWh and 1305 lb CO_2/MWh), with states having higher percentages of coal-fired generation receiving more stringent emission rate goals than those in the original proposal. The new rule also gives states an additional year to submit a state implementation plan, now September of 2018. Under the CPP, states have the flexibility to include energy efficiency and other measures should it choose to implement a state measures plan 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 glide path over the 2022-29 time period.

In the event that a state does not submit a state implementation plan (SIP), the EPA also released a proposed federal implementation plan (FIP), which would be imposed in those states without an approved SIP. The proposed FIP would apply an emission rate requirement directly on affected units. Under the proposed FIP the CO_2 emission rate limit for coal-fired units would start at 1671 lbs CO_2 / MWh in 2022 and decrease to a final emission rate cap of 1305 lbs CO_2 / MWh by 2030. While the FIP emission rate cap appears to be slightly less stringent, the cap would apply directly to affected units and these units would not have the benefit of averaging emission rates with rates from zero-carbon sources as in a SIP. Purchases of emission credits from zero-carbon sources can be made for compliance. Since the FIP has just been proposed, it will be subject to extensive public comments prior to finalization.

Indiana is the 5th largest carbon emitter in the nation in tons of CO_2 produced from electric generation. In 2013, Indiana’s electric utilities generated 105.6 million tons of CO_2. The Company’s share of that total was 6.3 million, or less than 6 percent. Since 2005, the Company’s emissions of CO_2 have declined 23 percent (on a tonnage basis). These reductions have come from the retirement of F.B. Culley Unit 1, expiration of municipal contracts, electric conservation and the addition of renewable generation and the installation of more efficient dense pack turbine technology. With respect to renewable generation, in 2008 and 2009, the Company executed long-term purchase power commitments for a total of 80 MW of wind energy. The Company currently has approximately 4 percent of its electricity being provided by clean energy sources due to the long-term wind contracts and landfill gas investment.

With respect to CO_2 emission rate, since 2005 the Company has lowered its CO_2 emission rate (as measured in lbs CO_2/MWh) from 1967 lbs CO_2/MWh to 1922 lbs CO_2/MWh, for a reduction of 3 percent. The Company's CO_2 emission rate of 1922 lbs/MWh is basically the same as the State's average CO_2 emission rate of 1923 lb CO_2/MWh.

Impact of Legislative Actions & Other Initiatives is Unknown

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 will undertake a detailed review of the requirements of the CPP and the proposed FIP and commence a review of potential compliance options for Vectren's affected units. In 2016 the Company will file its next integrated resource plan that will model compliance assumptions and costs and evaluate possible compliance alternatives. The Company will also continue to remain engaged with the State of Indiana to assess the final rule and to develop a plan that is the least cost to its customers. Costs to purchase allowances that cap GHG emissions or expenditures made to control emissions or lower carbon emission rates should be considered a federally mandated cost of providing electricity, and as such, the Company believes such costs and expenditures should be recoverable from customers through Senate Bill 251 as referenced above or Senate Bill 29, which was used by the Company to recover its initial pollution control investments.

Manufactured Gas Plants
In the past, the Company operated facilities to manufacture natural gas. Given the availability of natural gas transported by pipelines, these facilities have not been operated for many years. Under current environmental laws and regulations, those that owned or operated these facilities may now be required to take remedial action if certain contaminants are found above the regulatory thresholds.

In the Indiana Gas service territory, the existence, location, and certain general characteristics of 26 gas manufacturing and storage sites have been identified for which the Company may have some remedial responsibility. A remedial investigation/ feasibility study (RI/FS) was completed at one of the sites under an agreed upon order between Indiana Gas and the IDEM, and a Record of Decision was issued by the IDEM in January 2000. The remaining sites have been submitted to the IDEM's Voluntary Remediation Program (VRP). The Company has identified its involvement in five manufactured gas plant sites in SIGECO's service territory, all of which are currently enrolled in the IDEM's VRP. The Company is currently conducting some level of remedial activities, including groundwater monitoring at certain sites.

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

With respect to insurance coverage, Indiana Gas has received approximately $20.8 million from all known insurance carriers under insurance policies in effect when these plants were in operation. Likewise, SIGECO has settlement agreements with all known insurance carriers and has received to date approximately $14.3 million of the expected $15.8 million in insurance recoveries.

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company's utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of June 30, 2015 and December 31, 2014, approximately $3.4 million and $3.6

million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

Impact of Recently Issued Accounting Guidance

Revenue Recognition Guidance
In May 2014, the FASB issued new accounting guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for GAAP and IFRS. The amendments in this guidance state that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This new guidance requires improved disclosures to help users of financial statements better understand the nature, amount, timing, and uncertainty of revenue that is recognized. On July 9, 2015, the FASB approved a one year deferral of the effective date to December 15, 2017 with early adoption permitted, but not before the original effective date of December 15, 2016. The Company is currently evaluating the standard to determine application date, transition method, and impact the standard will have on the financial statements.
Financial Reporting of Discontinued Operations
In April 2014, the FASB issued new accounting guidance on reporting discontinued operations and disclosures of disposals of a company or entity. The guidance changes the criteria for reporting discontinued operations and provides for enhanced disclosures in this area. Under the new guidance, only disposals representing a strategic shift in operations should be presented as discontinued operations. Those strategic shifts should have a major effect on the organization's operations and financial results. Additionally, the new guidance requires expanded disclosures about discontinued operations to provide more information about the assets, liabilities, income, and expenses of discontinued operations. The new guidance also requires disclosure of the pre-tax income attributable to a disposal of a significant part of an organization that does not qualify for discontinued operations reporting. This guidance is effective for fiscal years beginning on or after December 15, 2014, with early adoption permitted. The Company adopted this guidance on January 1, 2015. The adoption of this guidance had no impact on the Company’s financial statements.

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

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 consolidated financial statements. Utility Holdings' long-term debt, including current maturities, outstanding at June 30, 2015 approximated $875 million. As of June 30, 2015, Utility Holdings had $27 million in short-term borrowings outstanding. Additionally, prior to Utility Holdings' formation, Indiana Gas and SIGECO funded their operations separately, and therefore, have long-term debt outstanding funded solely by their operations. SIGECO will also occasionally issue tax exempt debt to fund qualifying pollution control capital expenditures. Total Indiana Gas and SIGECO long-term debt, including current maturities, outstanding at June 30, 2015, was approximately $378 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 June 30, 2015, 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 55 percent of long-term capitalization at June 30, 2015 and 54 percent at December 31, 2014. 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 June 30, 2015, the Company was in compliance with all debt covenants.

Available Liquidity

The Company's A-/A2 investment grade credit ratings have allowed it to access the capital markets as needed, and the Company believes it will have the ability to continue to do so. Given the Company's intent to maintain a balanced long-term capitalization ratio, it anticipates funding future capital expenditures and dividends principally through internally generated funds supplemented with incremental external debt financing. However, the resources required for capital investment remain uncertain for a variety of factors including expanded EPA regulations for air, water, and fly ash. These regulations may result in the need to raise additional debt and equity capital in the coming years.

On March 15, 2015, a $5.0 million Indiana Gas senior unsecured note matured. The Series E note carried a fixed interest rate of 7.15%. The repayment of debt was funded by the Company's commercial paper program.

On June 11, 2015, Vectren Utility Holdings entered into a private placement Note Purchase Agreement pursuant to which institutional investors have agreed to purchase the following tranches of notes: (i) $25 million of 3.90% Guaranteed Senior Notes, Series A, due December 15, 2035, (ii) $135 million of 4.36% Guaranteed Senior Notes, Series B, due December, 15, 2045, and (iii) $40 million of 4.51% Guaranteed Senior Notes, Series C, due December 15, 2055. The notes will be unconditionally guaranteed by Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company and Vectren Energy Delivery of Ohio, Inc.

The proceeds from these issuances will be used to refinance existing indebtedness and for general corporate purposes including the Company's capital expenditure program. Subject to the satisfaction of customary conditions precedent, the financing is scheduled to close on or about December 15, 2015.

Consolidated Short-Term Borrowing Arrangements

At June 30, 2015, the Company has $350 million of short-term borrowing capacity. As reduced by borrowings currently outstanding, approximately $323 million was available at June 30, 2015. This short-term credit facility was amended on October 31, 2014 to, among other things, extend the maturity until October 31, 2019. The maximum limit of the facility remained unchanged. This facility is used to supplement working capital needs and also to fund capital investments and debt redemptions until financed on a long-term basis.

The Company has historically funded its short-term borrowing needs through the commercial paper market and expects to use the short-term borrowing facility in instances where the commercial paper market is not efficient.

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

(In millions)	2015	2014
As of June 30		
Balance Outstanding	$27.3	$3.7
Weighted Average Interest Rate	0.36%	0.30%
Six Months Ended June 30 Average		
Balance Outstanding	$36.2	$1.3
Weighted Average Interest Rate	0.39%	0.28%
Maximum Month End Balance Outstanding	$121.5	$3.7

(In millions)	2015	2014
Quarterly Average - June 30		
Balance Outstanding	$3.5	$0.6
Weighted Average Interest Rate	0.35%	0.33%
Maximum Month End Balance Outstanding	$27.3	$3.7

Potential Uses of Liquidity

Pension Funding Obligations

For the six months ended June 30, 2015, Vectren contributed $20 million to its qualified pension plans. Utility Holdings will fund a portion of the total contribution as it relates to its plans. Vectren does not anticipate making further contributions in 2015.

Planned Capital Expenditures

Capital expenditures are estimated at $235 million for the remainder of 2015.

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 $336.8 million and $213.2 million for the six months ended June 30, 2015 and 2014, respectively. The increase is driven primarily by certain weather related impacts to working capital accounts. Weather related impacts include the fluctuation in the recoverable/refundable natural gas and fuel costs and accounts receivable. Additionally, a decrease in prepaid taxes was due to a federal refund received in 2015 related to the extension of bonus depreciation in 2014.

Financing Cash Flow
Net cash flow required for financing activities was $186.3 million and $76.0 million during the six months ended June 30, 2015 and 2014, respectively. The current year period, compared to the second quarter of 2014, reflects a greater decrease of short term borrowings of $104.2 million. Financing activity in both periods presented reflects the payment of dividends.

Investing Cash Flow
Cash flow required for investing activities was $163.1 million and $140.9 million during the six months ended June 30, 2015 and 2014, respectively. The primary use of cash in both periods presented reflect 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 unusual weather conditions; catastrophic weather-related damage; unusual maintenance or repairs; unanticipated changes to coal and natural gas costs; unanticipated changes to gas transportation and storage costs, or availability due to higher demand, shortages, transportation problems or other developments; environmental or pipeline incidents; transmission or distribution incidents; unanticipated changes to electric energy supply costs, or availability due to demand, shortages, transmission problems or other developments; or electric transmission or gas pipeline system constraints.
- Catastrophic events such as fires, earthquakes, explosions, floods, ice storms, tornadoes, terrorist acts, cyber attacks, or other similar occurrences could adversely affect the Company's facilities, operations, financial condition, results of operations, and reputation.
- Increased competition in the energy industry, including the effects of industry restructuring, unbundling, and other sources of energy.
- Regulatory factors such as unanticipated changes in rate-setting policies or procedures, recovery of investments and costs made under regulation, interpretation of regulatory-related legislation by the IURC and/or PUCO and appellate courts that review decisions issued by the agencies, and the frequency and timing of rate increases.
- Financial, regulatory or accounting principles or policies imposed by the Financial Accounting Standards Board; the Securities and Exchange Commission; the Federal Energy Regulatory Commission; state public utility commissions; state entities which regulate electric and natural gas transmission and distribution, natural gas gathering and processing, electric power supply; and similar entities with regulatory oversight.
- Economic conditions including the effects of inflation rates, commodity prices, and monetary fluctuations.
- Economic conditions surrounding the current economic uncertainty, including increased potential for lower levels of economic activity; uncertainty regarding energy prices and the capital and commodity markets; volatile changes in the demand for natural gas and electricity; impacts on both gas and electric large customers; lower residential and commercial customer counts; 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.

43

- Employee or contractor workforce factors including changes in key executives, collective bargaining agreements with union employees, aging workforce issues, work stoppages, or pandemic illness.
- Risks associated with material business transactions such as acquisitions and divestitures, including, without limitation, legal and regulatory delays; the related time and costs of implementing such transactions; integrating operations as part of these transactions; and possible failures to achieve expected gains, revenue growth and/or expense savings from such transactions.
- Costs, fines, penalties and other effects of legal and administrative proceedings, settlements, investigations, claims, including, but not limited to, such matters involving compliance with federal and state laws and interpretations of these laws.
- Changes in or additions to federal, state or local legislative requirements, such as changes in or additions to tax laws or rates, pipeline safety regulations, environmental laws, including laws governing greenhouse gases, mandates of sources of renewable energy, and other regulations.

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to various business risks associated with 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. 2014 Form 10-K and is therefore not presented herein.

ITEM 4. CONTROLS AND PROCEDURES

Changes in Internal Controls over Financial Reporting

During the quarter ended June 30, 2015, there have been no changes to the Company's internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of June 30, 2015, the Company conducted an evaluation under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer of the effectiveness and the design and operation of the Company's disclosure controls and procedures. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective as of June 30, 2015, to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is:

1) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and

2) accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

PART II. 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, rate and regulatory matters. The condensed consolidated financial statements are included in Part 1 Item 1.

During the third quarter of 2014, the Company was notified of claims by a group of current and former SIGECO employees ("claimants") who participated in the Pension Plan for Salaried Employees of SIGECO ("SIGECO Salaried Plan"). That plan was merged into the Vectren Corporation Combined Non-Bargaining Retirement Plan ("Vectren Combined Plan") effective July 1, 2000. The claims relate to the claimants' election for benefits to be calculated under the Vectren Combined Plan's cash-balance formula rather than the SIGECO Salaried Plan formula in effect prior to the formation of Vectren. On March 12, 2015, certain claimants filed a Class Action Complaint against the Vectren Combined Plan and the Company in federal district court requesting that a class be certified and for various relief including that the Combined Plan be reformed and benefits thereunder be recalculated. The Company denied the allegations set forth in the Complaint.

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

ITEM 1A. RISK FACTORS

Investors should consider carefully factors that may impact the Company's operating results and financial condition, causing them to be materially adversely affected. The Company's risk factors have not materially changed from the information set forth in Item 1A Risk Factors included in the Vectren Utility Holdings 2014 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

4.1	Note Purchase Agreement, dated June 11, 2015, between Vectren Utility Holdings, Inc. and each of the purchasers named therein. (Filed and designated in Form 8-K dated June 12, 2015 File No. 1-16739, as Exhibit 4.1).
10.2	Coal Supply Agreement for A.B. Brown Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., effective January 1, 2015. Contract assigned to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 10-Q dated March 31, 2015, File No. 1-16739, as Exhibit 10.2.) Portions of the document have been omitted and filed separately pursuant to a request for confidential treatment filed with the Securities and Exchange Commission which was granted.
10.3	Coal Supply Agreement for F.B. Culley Generating Station between Southern Indiana Gas and Vectren Fuels, Inc., effective January 1, 2015. Contract assigned to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 10-Q dated March 31, 2015, File No. 1-16739, as Exhibit 10.3.) Portions of the document have been omitted and filed separately pursuant to a request for confidential treatment filed with the Securities and Exchange Commission which was granted.
10.4	Coal Supply Agreement for Warrick 4 Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., effective January 1, 2015. Contract assigned to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 10-Q dated March 31, 2015, File No. 1-16739, as Exhibit 10.4.) Portions of the document have been omitted and filed separately pursuant to a request for confidential treatment filed with the Securities and Exchange Commission which was granted.
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

August 13, 2015	/s/M. Susan Hardwick M. Susan Hardwick Senior Vice President and Chief Financial Officer (Signing on behalf of the registrant and as Principal Accounting & Financial Officer)