VECTREN UTILITY HOLDINGS INC
Form 10-Q
August 11, 2014

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, 2014
OR

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

For the transition period from __________________ to __________________

Commission file number: 1-16739

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, 2014
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: Robert L. Goocher 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 (formerly Midwest Independent System Operator)
EPA: Environmental Protection Agency	MMBTU: millions of British thermal units
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	OCC: Ohio Office of the Consumer Counselor
IDEM: Indiana Department of Environmental Management	OUCC: Indiana Office of the Utility Consumer Counselor
IURC: Indiana Utility Regulatory Commission	PUCO: Public Utilities Commission of Ohio
Kv: Kilovolt	Throughput: combined gas sales and gas transportation volumes
MCF / BCF: thousands / billions of cubic feet	XBRL: eXtensible Business Reporting Language

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	June 30, 2014	December 31, 2013
ASSETS		
Current Assets		
Cash & cash equivalents	$4.9	$8.6
Accounts receivable - less reserves of $6.1 & $5.0, respectively	77.8	112.1
Accrued unbilled revenues	42.8	113.5
Inventories	73.5	89.9
Recoverable fuel & natural gas costs	25.6	5.5
Prepayments & other current assets	33.0	42.4
Total current assets	257.6	372.0
Utility Plant		
Original cost	5,514.4	5,389.6
Less: accumulated depreciation & amortization	2,228.2	2,165.3
Net utility plant	3,286.2	3,224.3
Investments in unconsolidated affiliates	0.2	0.2
Other investments	26.1	27.3
Nonutility plant - net	151.3	150.5
Goodwill - net	205.0	205.0
Regulatory assets	122.2	136.2
Other assets	21.9	25.3
TOTAL ASSETS	$4,070.5	$4,140.8

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

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

	June 30, 2014	December 31, 2013
LIABILITIES & SHAREHOLDER'S EQUITY		
Current Liabilities		
Accounts payable	$80.1	$172.1
Payables to other Vectren companies	29.1	24.6
Accrued liabilities	121.5	127.4
Short-term borrowings	3.7	28.6
Current maturities of long-term debt	5.0	—
Total current liabilities	239.4	352.7
Long-Term Debt - Net of Current Maturities	1,252.2	1,257.1
Deferred Credits & Other Liabilities		
Deferred income taxes	627.5	627.4
Regulatory liabilities	400.2	387.3
Deferred credits & other liabilities	85.4	83.5
Total deferred credits & other liabilities	1,113.1	1,098.2
Commitments & Contingencies (Notes 7 - 9)		
Common Shareholder's Equity		
Common stock (no par value)	790.8	787.7
Retained earnings	675.0	645.1
Total common shareholder's equity	1,465.8	1,432.8
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$4,070.5	$4,140.8

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

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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,	
	2014	2013	2014	2013
OPERATING REVENUES				
Gas utility	$132.4	$138.0	$576.0	$453.9
Electric utility	152.0	154.7	315.0	304.2
Other	0.1	0.1	0.1	0.2
Total operating revenues	284.5	292.8	891.1	758.3
OPERATING EXPENSES				
Cost of gas sold	43.7	50.7	314.6	207.9
Cost of fuel & purchased power	48.1	53.9	105.1	104.1
Other operating	81.5	76.1	179.8	162.9
Depreciation & amortization	50.6	48.7	100.5	97.1
Taxes other than income taxes	12.5	12.2	32.6	29.7
Total operating expenses	236.4	241.6	732.6	601.7
OPERATING INCOME	48.1	51.2	158.5	156.6
Other income - net	3.7	3.0	7.6	4.8
Interest expense	16.7	15.7	33.4	33.6
INCOME BEFORE INCOME TAXES	35.1	38.5	132.7	127.8
Income taxes	12.2	14.3	48.5	48.5
NET INCOME	$22.9	$24.2	$84.2	$79.3

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

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

	Six Months Ended June 30, 2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$84.2	$79.3
Adjustments to reconcile net income to cash from operating activities:		
Depreciation & amortization	100.5	97.1
Deferred income taxes & investment tax credits	17.0	16.5
Expense portion of pension & postretirement periodic benefit cost	2.3	2.7
Provision for uncollectible accounts	2.3	3.9
Other non-cash expense - net	1.5	2.9
Changes in working capital accounts:		
Accounts receivable & accrued unbilled revenue	102.8	56.1
Inventories	16.4	22.3
Recoverable/refundable fuel & natural gas costs	(22.7)	6.7
Prepayments & other current assets	4.1	6.7
Accounts payable, including to Vectren companies & affiliated companies	(88.9)	(88.0)
Accrued liabilities	(5.6)	(6.4)
Changes in noncurrent assets	5.8	(0.6)
Changes in noncurrent liabilities	(6.5)	(2.1)
Net cash provided by operating activities	213.2	197.1
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from:		
Long-term debt - net of issuance costs	—	122.3
Additional capital contribution	3.2	3.0
Requirements for:		
Dividends to parent	(54.3)	(52.6)
Retirement of long-term debt	—	(175.7)
Net change in short-term borrowings	(24.9)	7.3
Net cash used in financing activities	(76.0)	(95.7)
CASH FLOWS FROM INVESTING ACTIVITIES		
Proceeds from other investing activities	0.1	0.1
Requirements for:		
Capital expenditures, excluding AFUDC equity	(141.0)	(110.9)
Net cash used in investing activities	(140.9)	(110.8)
Net change in cash & cash equivalents	(3.7)	(9.4)
Cash & cash equivalents at beginning of period	8.6	13.3
Cash & cash equivalents at end of period	$4.9	$3.9

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

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

1. Organization and Nature of Operations

Vectren Utility Holdings, Inc. (the Company, Utility Holdings or VUHI), an Indiana corporation, was formed on March 31, 2000 to serve as the intermediate holding company for Vectren Corporation's (Vectren) three operating public utilities: Indiana Gas Company, Inc. (Indiana Gas), Southern Indiana Gas and Electric Company (SIGECO), and Vectren Energy Delivery of Ohio, Inc. (VEDO). Utility Holdings also has other assets that provide information technology and other services to the three utilities. 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 578,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 143,000 electric customers and approximately 111,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to approximately 315,000 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, 2013, filed with the Securities and Exchange Commission on March 5, 2014, 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 $3.7 million was outstanding at June 30, 2014, and Utility Holdings' has unsecured senior notes with a par value of $875 million outstanding at June 30, 2014. 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 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, 2014 (in millions):

ASSETS	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Assets				
Cash & cash equivalents	$2.9	$2.0	$—	$4.9
Accounts receivable - less reserves	77.8	—	—	77.8
Intercompany receivables	88.1	37.5	(125.6)	—
Accrued unbilled revenues	42.8	—	—	42.8
Inventories	73.5	—	—	73.5
Recoverable fuel & natural gas costs	25.6	—	—	25.6
Prepayments & other current assets	31.1	37.4	(35.5)	33.0
Total current assets	341.8	76.9	(161.1)	257.6
Utility Plant				
Original cost	5,514.4	—	—	5,514.4
Less: accumulated depreciation & amortization	2,228.2	—	—	2,228.2
Net utility plant	3,286.2	—	—	3,286.2
Investments in consolidated subsidiaries	—	1,406.4	(1,406.4)	—
Notes receivable from consolidated subsidiaries	—	820.6	(820.6)	—
Investments in unconsolidated affiliates	0.2	—	—	0.2
Other investments	21.7	4.4	—	26.1
Nonutility property - net	2.0	149.3	—	151.3
Goodwill - net	205.0	—	—	205.0
Regulatory assets	100.0	22.2	—	122.2
Other assets	30.6	0.7	(9.4)	21.9
TOTAL ASSETS	$3,987.5	$2,480.5	$(2,397.5)	$4,070.5

LIABILITIES & SHAREHOLDER'S EQUITY	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Liabilities				
Accounts payable	$75.2	$4.9	$—	$80.1
Intercompany payables	13.7	—	(13.7)	—
Payables to other Vectren companies	29.1	—	—	29.1
Accrued liabilities	145.7	11.3	(35.5)	121.5
Short-term borrowings	—	3.7	—	3.7
Intercompany short-term borrowings	23.9	88.0	(111.9)	—
Current maturities of long-term debt	5.0	—	—	5.0
Total current liabilities	292.6	107.9	(161.1)	239.4
Long-Term Debt				
Long-term debt	377.6	874.6	—	1,252.2
Long-term debt due to VUHI	820.6	—	(820.6)	—
Total long-term debt - net	1,198.2	874.6	(820.6)	1,252.2
Deferred Credits & Other Liabilities				
Deferred income taxes	601.4	26.1	—	627.5
Regulatory liabilities	398.7	1.5	—	400.2
Deferred credits & other liabilities	90.2	4.6	(9.4)	85.4
Total deferred credits & other liabilities	1,090.3	32.2	(9.4)	1,113.1
Common Shareholder's Equity				
Common stock (no par value)	804.1	790.8	(804.1)	790.8
Retained earnings	602.3	675.0	(602.3)	675.0

Total common shareholder's equity	1,406.4	1,465.8	(1,406.4	) 1,465.8
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$3,987.5	$2,480.5	$(2,397.5	) $4,070.5

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Condensed Consolidating Balance Sheet as of December 31, 2013 (in millions):

ASSETS	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Assets				
Cash & cash equivalents	$8.2	$0.4	$—	$8.6
Accounts receivable - less reserves	112.1	—	—	112.1
Intercompany receivables	0.3	84.8	(85.1)	—
Accrued unbilled revenues	113.5	—	—	113.5
Inventories	89.9	—	—	89.9
Recoverable fuel & natural gas costs	5.5	—	—	5.5
Prepayments & other current assets	37.3	40.1	(35.0)	42.4
Total current assets	366.8	125.3	(120.1)	372.0
Utility Plant				
Original cost	5,389.6	—	—	5,389.6
Less: accumulated depreciation & amortization	2,165.3	—	—	2,165.3
Net utility plant	3,224.3	—	—	3,224.3
Investments in consolidated subsidiaries	—	1,375.8	(1,375.8)	—
Notes receivable from consolidated subsidiaries	—	696.4	(696.4)	—
Investments in unconsolidated affiliates	0.2	—	—	0.2
Other investments	22.8	4.5	—	27.3
Nonutility property - net	2.2	148.3	—	150.5
Goodwill - net	205.0	—	—	205.0
Regulatory assets	113.4	22.8	—	136.2
Other assets	32.2	1.0	(7.9)	25.3
TOTAL ASSETS	$3,966.9	$2,374.1	$(2,200.2)	$4,140.8

LIABILITIES & SHAREHOLDER'S EQUITY	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Liabilities				
Accounts payable	$161.6	$10.5	$—	$172.1
Intercompany payables	11.7	—	(11.7)	—
Payables to other Vectren companies	24.6	—	—	24.6
Accrued liabilities	150.3	12.1	(35.0)	127.4
Short-term borrowings	—	28.6	—	28.6
Intercompany short-term borrowings	73.1	0.3	(73.4)	—
Total current liabilities	421.3	51.5	(120.1)	352.7
Long-Term Debt				
Long-term debt - net of current maturities & debt subject to tender	382.5	874.6	—	1,257.1
Long-term debt due to VUHI	696.4	—	(696.4)	—
Total long-term debt - net	1,078.9	874.6	(696.4)	1,257.1
Deferred Credits & Other Liabilities				
Deferred income taxes	616.9	10.5	—	627.4
Regulatory liabilities	385.7	1.6	—	387.3
Deferred credits & other liabilities	88.3	3.1	(7.9)	83.5
Total deferred credits & other liabilities	1,090.9	15.2	(7.9)	1,098.2
Common Shareholder's Equity				
Common stock (no par value)	800.9	787.7	(800.9)	787.7
Retained earnings	574.9	645.1	(574.9)	645.1

Total common shareholder's equity	1,375.8	1,432.8	(1,375.8)	1,432.8
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$3,966.9	$2,374.1	$(2,200.2)	$4,140.8

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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

Condensed Consolidating Statement of Income for the three months ended June 30, 2013 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	$138.0	$—	$—	$138.0
Electric utility	154.7	—	—	154.7
Other	—	9.5	(9.4)	0.1
Total operating revenues	292.7	9.5	(9.4)	292.8
OPERATING EXPENSES				
Cost of gas sold	50.7	—	—	50.7
Cost of fuel & purchased power	53.9	—	—	53.9
Other operating	85.2	—	(9.1)	76.1
Depreciation & amortization	43.3	5.3	0.1	48.7
Taxes other than income taxes	11.8	0.4	—	12.2
Total operating expenses	244.9	5.7	(9.0)	241.6
OPERATING INCOME	47.8	3.8	(0.4)	51.2
Other income - net	1.8	9.1	(7.9)	3.0
Interest expense	13.8	10.2	(8.3)	15.7
INCOME BEFORE INCOME TAXES	35.8	2.7	—	38.5
Income taxes	14.0	0.3	—	14.3
Equity in earnings of consolidated companies, net of tax	—	21.8	(21.8)	—

NET INCOME	$21.8	$24.2	$(21.8)	$24.2

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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

Condensed Consolidating Statement of Income for the six months ended June 30, 2013 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	$453.9	$—	$—	$453.9
Electric utility	304.2	—	—	304.2
Other	—	19.0	(18.8)	0.2
Total operating revenues	758.1	19.0	(18.8)	758.3
OPERATING EXPENSES				
Cost of gas sold	207.9	—	—	207.9
Cost of fuel & purchased power	104.1	—	—	104.1
Other operating	181.2	—	(18.3)	162.9
Depreciation & amortization	86.4	10.5	0.2	97.1
Taxes other than income taxes	28.9	0.8	—	29.7
Total operating expenses	608.5	11.3	(18.1)	601.7
OPERATING INCOME	149.6	7.7	(0.7)	156.6
Other income - net	3.7	18.8	(17.7)	4.8
Interest expense	30.0	22.0	(18.4)	33.6
INCOME BEFORE INCOME TAXES	123.3	4.5	—	127.8
Income taxes	48.8	(0.3)	—	48.5
Equity in earnings of consolidated companies, net of tax	—	74.5	(74.5)	—
NET INCOME	$74.5	$79.3	$(74.5)	$79.3

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

Condensed Consolidating Statement of Cash Flows for the six months ended June 30, 2013 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH PROVIDED BY OPERATING ACTIVITIES	$199.1	$(2.0)	$—	$197.1
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from:				
Long-term debt, net of issuance costs	60.0	124.4	(62.1)	122.3
Additional capital contribution from parent	10.0	3.0	(10.0)	3.0
Requirements for:				
Dividends to parent	(49.0)	(52.6)	49.0	(52.6)
Retirement of long term debt	(174.8)	(121.6)	120.7	(175.7)
Net change in intercompany short-term borrowings	49.0	—	(49.0)	—
Net change in short-term borrowings	—	7.3	—	7.3
Net cash used in financing activities	(104.8)	(39.5)	48.6	(95.7)
CASH FLOWS FROM INVESTING ACTIVITIES				
Proceeds from:				
Consolidated subsidiary distributions	—	49.0	(49.0)	—
Other investing activities	—	0.1	—	0.1
Requirements for:				
Capital expenditures, excluding AFUDC equity	(103.3)	(7.6)	—	(110.9)

Consolidated subsidiary investments	—	(10.0)	10.0	—
Net change in long-term intercompany notes receivable	—	58.6	(58.6)	—
Net change in short-term intercompany notes receivable	—	(49.0)	49.0	—
Net cash used in investing activities	(103.3)	41.1	(48.6)	(110.8)
Net change in cash & cash equivalents	(9.0)	(0.4)	—	(9.4)
Cash & cash equivalents at beginning of period	12.5	0.8	—	13.3
Cash & cash equivalents at end of period	$3.5	$0.4	$—	$3.9

4. Excise and Utility Receipts Taxes

Excise taxes and a portion of utility receipts taxes are included in rates charged to customers. Accordingly, the Company records these taxes received as a component of operating revenues, which totaled $5.5 million and $5.4 million in the three months ended June 30, 2014 and 2013, respectively. For the six months ended June 30, 2014 and 2013, these taxes totaled $18.4 million and $16.1 million, respectively. Expense 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, 2014 and December 31, 2013, the Company has accruals related to utility and nonutility plant purchases totaling approximately $14.9 million and $13.1 million, respectively.

6. Transactions with Other Vectren Companies and Affiliates

Vectren Fuels, Inc. (Vectren Fuels)
Vectren Fuels, a wholly owned subsidiary of Vectren, owns coal mines from which SIGECO purchases coal used for electric generation. The price of coal that is charged by Vectren Fuels to SIGECO is priced consistent with contracts reviewed by the OUCC and on file with the IURC. Amounts purchased for the three months ended June 30, 2014 and 2013 totaled $37.8 million and $31.7 million, respectively, and for the six months ended June 30, 2014 and 2013 totaled $68.6 million and $51.6 million, respectively. Amounts owed to Vectren Fuels at June 30, 2014 and December 31, 2013 are included in Payables to other Vectren companies in the Condensed Consolidated Balance Sheets.

Vectren Infrastructure Services Corporation (VISCO)
VISCO, a wholly owned subsidiary of Vectren, performs natural gas and water distribution, transmission, and construction repair and rehabilitation primarily in the Midwest and the repair and rehabilitation of gas, water, and wastewater facilities nationwide. In addition, VISCO also provides transmission pipeline construction and maintenance; pump station, compressor station, terminal and refinery construction; and hydrostatic testing to customers generally in the northern Midwest region. VISCO's customers include Utility Holdings' utilities. Fees incurred by Utility Holdings and its subsidiaries totaled $22.0 million and $13.2 million for the three months ended June 30, 2014 and 2013, respectively, and for the six months ended June 30, 2014 and 2013 totaled $33.4 million and $23.6 million, respectively. Amounts owed to VISCO at June 30, 2014 and December 31, 2013 are included in Payables to other Vectren companies in the Condensed Consolidated Balance Sheets.

ProLiance Holdings, LLC (ProLiance)
Vectren has an investment in ProLiance, a nonutility affiliate of Vectren and Citizens Energy Group (Citizens). On June 18, 2013, ProLiance exited the natural gas marketing business through the disposition of certain of the net assets of its energy marketing business, ProLiance Energy, LLC (ProLiance Energy). ProLiance Energy provided services to a broad range of municipalities, utilities, industrial operations, schools, and healthcare institutions located throughout the Midwest and Southeast United States. ProLiance Energy's customers included, among others, Vectren's Indiana utilities as well as Citizens' utilities.

Purchases from ProLiance for resale and for injections into storage for the three months ended June 30, 2013 totaled $92.9 million and for the six months ended June 30, 2013 totaled $200.5 million. The Company had no purchases during 2014 as a result of Proliance exiting the natural gas marketing business. The Company did not have any amounts owed to ProLiance for purchases at June 30, 2014 and at December 31, 2013. Amounts charged by ProLiance for gas supply services were established by supply agreements with each utility. After the exit of the energy marketing business by ProLiance, the Company purchases gas supply from third parties and 83 percent is from a single third party for the three and six month periods ended June 30, 2014.

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

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months ended June 30, 2014 and 2013, Utility Holdings received corporate allocations totaling $14.6 million and $11.4 million, respectively. For the six months ending June 30, 2014 and 2013, Utility Holdings received corporate allocations totaling $29.3 million and $26.3 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. 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 and certain contracts are firm commitments under five and ten year arrangements. Costs arising from these commitments, while significant, are pass-through costs, generally collected dollar-for-dollar from retail customers through regulator-approved cost recovery mechanisms.

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.

8. Rate & Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement
Vectren monitors and maintains its natural gas distribution system to ensure that natural gas is delivered in a safe and efficient manner. Vectren's natural gas utilities are currently engaged in replacement programs in both Indiana and Ohio, to mitigate risk, improve the system, and comply with applicable regulations. Laws in both Indiana and Ohio were passed that provide utilities the opportunity to timely recover costs of federally mandated projects and other infrastructure improvement projects outside of a base rate proceeding.

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 $118 million. Regulatory assets associated with post in service carrying costs and depreciation deferrals were $11.2 million and $9.3 million at June 30, 2014 and December 31, 2013, respectively. Due to the expiration of the initial five year term for the DRR in early 2014, the Company filed a request in August 2013 to extend and expand the DRR. On February 19, 2014, the PUCO approved 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 also approved an adjustment to the bill impact evaluation, limiting the resulting DRR rate 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 $187 million. In addition, the Order approved the Company's

commitment that the DRR can only be further extended as part of a base rate case. On May 1, 2014, the Company filed its annual request to adjust the DRR for recovery of costs incurred through December 31, 2013. On July 25, 2014, the PUCO staff completed its audit and recommended approval of the DRR as filed. A hearing in this proceeding is scheduled for August 6, 2014, and an order is expected later in 2014.

In June 2011, Ohio House Bill 95 was signed into law. Outside of a base rate proceeding, this legislation permits a natural gas company 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. On December 12, 2012, the PUCO issued an order approving the Company's initial application under this law, reflecting its capital expenditure program covering the fifteen month period ending December 31, 2012. Such capital expenditures include infrastructure expansion and improvements not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. The order also 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. In addition, the order approved the Company's proposal that subsequent requests for accounting authority will be filed annually in April. The Company submitted its most recent annual filing on April 30, 2014, which covers the Company’s capital expenditure program through calendar year 2014.

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 rate increase limits discussed above are not expected to be reached given this capital expenditure plan during the remaining four year time frame.

Indiana Recovery and Deferral Mechanisms

The Company's Indiana natural gas utilities received orders in 2008 and 2007 associated with the most recent base rate cases. These orders authorized the deferral of financial impacts associated with bare steel and cast iron replacement activities. The orders provide for the deferral of depreciation and post in service carrying costs on qualifying projects totaling $20 million annually at Indiana Gas and $3 million annually at SIGECO. The debt-related post in service carrying costs are recognized in the Condensed Consolidated Statements of Income currently. The recording of post in service carrying costs and depreciation deferral is limited by individual qualifying project to three years after being placed into service at SIGECO and four years after being placed into service at Indiana Gas. At June 30, 2014 and December 31, 2013, the Company has regulatory assets totaling $14.3 million and $12.1 million, respectively, associated with the deferral of depreciation and debt-related post in service carrying cost activities.

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

In April 2013, Senate Bill 560 was signed into law. This legislation supplements Senate Bill 251 described above, which addressed federally mandated investment, 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 recovery using a periodic rate adjustment mechanism. Recoverable costs include a return on and of the investment, as well as property taxes and operating expenses. The remaining 20 percent of project costs are to be deferred for future recovery in the Company's next general rate case, which must be filed no later than the end of the seven year plan. The adjustment mechanism is capped at an annual increase in retail revenues of no more than two percent.

Pipeline Safety Law

On January 3, 2012, the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (Pipeline Safety Law) was signed into law. The Pipeline Safety Law, which reauthorizes federal pipeline safety programs through fiscal year

2015, provides for enhanced safety, reliability, and environmental protection in the transportation of energy products by pipeline. The law increases federal enforcement authority; grants the federal government expanded authority over pipeline safety; provides for new safety regulations and standards; and authorizes or requires the completion of several pipeline safety-related studies. The DOT is required to promulgate a number of new regulatory requirements over the next two years. Those regulations may eventually lead to further regulatory or statutory requirements.

While the Company continues to study the impact of the Pipeline Safety Law and potential new regulations associated with its implementation, it is expected that the law will result in further investment in pipeline inspections, and where necessary, additional investments in pipeline infrastructure and, therefore, result in both increased levels of operating expenses and capital expenditures associated with the Company's natural gas distribution businesses.

Requests for Recovery Under Indiana Regulatory Mechanisms
The Company filed in November 2013 for authority to recover costs related to its gas infrastructure replacement and improvement programs in Indiana, including costs associated with existing pipeline safety regulations, using the mechanisms allowed under Senate Bill 251 and Senate Bill 560. The combined SIGECO and Indiana Gas filing requests recovery of the capital expenditures associated with the infrastructure replacement and improvement plan pursuant to the legislation, estimated to be approximately $865 million combined, inclusive of an estimated $30 million of possible economic development related expenditures, over the seven year period beginning in 2014. The plan also includes approximately $13 million of combined annual operating costs associated with pipeline safety rules. Intervening parties to the proceeding filed testimony that generally supports the Company's plan and the mechanism for recovery. A hearing in this proceeding was held May 8, 2014, and proposed orders have been filed by all parties. An order is expected in late third quarter of 2014.

SIGECO Electric Environmental Compliance Filing
On January 17, 2014, SIGECO filed a request with the IURC for approval of capital investments estimated to be between $70 million and $90 million on its coal-fired generation units to comply with new EPA mandates related to mercury and air toxin standards effective in 2016 and to address an outstanding Notice of Violation (NOV) from the EPA. Roughly half of the investment will be made to control mercury in both air and water emissions. The remaining investment will be made to address the NOV on alleged increases in sulfur trioxide emissions. Although the Company believes these investments are recoverable as a federally mandated investment under Senate Bill 251, the Company has requested deferred accounting treatment in lieu of timely recovery to avoid immediate customer bill impacts. The accounting treatment request seeks 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 Company filed its case-in-chief on March 14, 2014. Intervening parties filed their testimony on May 28, 2014, to which the Company responded with rebuttal testimony on June 20, 2014. A hearing was held beginning on July 30, 2014. An order is expected in the fourth quarter of 2014.

Coal Procurement Procedures
SIGECO submitted a request for proposal (RFP) in April 2011 regarding coal purchases for a four year period beginning in 2012. After negotiations with bidders, SIGECO reached an agreement in principle for multi-year purchases with two suppliers, one of which was Vectren Fuels, Inc. Consistent with the IURC direction in the Company’s last electric rate case, a sub docket proceeding was established to review the Company’s prospective coal procurement procedures. In March 2012, the IURC issued its order in that sub docket which concluded that SIGECO’s 2011 RFP process resulted in the lowest fuel cost reasonably possible. SIGECO has long term contracts with Vectren Fuels to provide supply for its generating units. Those contracts will be reviewed in a pending sub docket proceeding. A hearing will be held in October 2014. Once the pending sale of Vectren Fuels is closed, Sunrise Coal will assume responsibility for fulfilling those contract obligations. Procuring this coal is part of the Company’s MATS compliance strategy.

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 will be 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, starting February 2014, was $42.4 million, of which $38.9 million remains as of June 30, 2014.

SIGECO Electric Demand Side Management Program Filing

On August 16, 2010, SIGECO filed a petition with the IURC, seeking approval of its proposed electric Demand Side Management (DSM) Programs, recovery of the costs associated with these programs, recovery of lost margins as a result of implementing these programs for large customers, and recovery of performance incentives linked with specific measurement criteria on all programs. The DSM Programs proposed were consistent with a December 9, 2009 order issued by the IURC, which, among other actions, defined long-term conservation objectives and goals of DSM programs for all Indiana electric utilities under a consistent statewide approach. In order to meet these objectives, the IURC order divided the DSM programs into Core and Core Plus programs. Core programs are joint programs required to be offered by all Indiana electric utilities to all customers, and include some for large industrial customers. Core Plus programs are those programs not required specifically by the IURC, but defined by each utility to meet the overall energy savings targets defined by the IURC.

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 discussed earlier. For the six months ended June 30, 2014, the Company recognized Electric revenue of $4.4 million associated with this approved lost margin recovery mechanism.

On March 28, 2014, Senate Bill 340 was signed into law. This legislation ends electric DSM programs on December 31, 2014 that have been conducted to meet the energy savings requirements established in the Commission's 2009 order. The legislation also allows for industrial customers to opt out of participating in energy efficiency programs. As of July 1, 2014, approximately 71 percent of the Company’s eligible industrial load has opted out of participation in the applicable energy efficiency programs. Indiana's Governor has requested that the Commission make new recommendations for energy efficiency programs to be proposed for 2015 and beyond, and has also asked the legislature to consider further legislation requiring some level of utility sponsored energy efficiency programs. The Company has filed a request for Commission approval of a new portfolio of DSM programs on May 29, 2014 to be effective in January 2015. On July 23, 2014, the OUCC and the Company filed a Notice of Settlement regarding the new portfolio with the Commission. A hearing in this proceeding is scheduled for September 3, 2014.

Indiana Gas Pipeline Safety Investigation

On April 11, 2012, the IURC's pipeline safety division filed a complaint against Indiana Gas alleging several violations of safety regulations pertaining to damage that occurred at a residence in Indiana Gas's service territory during a pipeline replacement project. The Company negotiated a settlement with the IURC's pipeline safety division, agreeing to a fine and several modifications to the Company's operating policies. The amount of the fine was not material to the Company's financial results. The IURC approved the settlement but modified certain terms of the settlement and added a requirement that Company employees conduct inspections of pipeline excavations. The Company sought and was granted a request for rehearing on the sole issue related to the requirement to use Company employees to inspect excavations. A settlement in the case was reached between the IURC's pipeline safety division and Indiana Gas that allowed Indiana Gas to continue to use its risk based approach to inspecting excavations and to allow the Company to continue using a mix of highly trained and qualified contractors and employees to perform inspections. On January 15, 2014, the IURC issued a Final Order in the case approving the settlement agreement, without modification.

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 gas companies and recovery of new conservation program costs through December 2015. The order provides that the companies must submit an extension proposal no later than March 1, 2015.

FERC Return on Equity 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. In the event a refund is required upon resolution of the complaint, the parties are seeking a refund calculated as of the filing date of the complaint. The MISO transmission owners filed their response to the complaint on January 6, 2014, opposing any change to the return. In addition to the group response, the Company filed a supplemental response, stating that if FERC allows the complaint to go forward, the complaint should not be applied to the Company’s recently completed Gibson-Brown-Reid 345 Kv transmission line investment. As of June 30, 2014, the Company had invested approximately $157.6 million in qualifying projects. The net plant balance for these projects totaled $145.2 million at June 30, 2014.

FERC has no deadline for action. 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. In August 2013, a FERC administrative law judge recommended in that proceeding that the return be lowered to 9.7 percent, retroactive to the date of the complaint filing. On June 19, 2014, the FERC voted to approve an order in this proceeding that allows for a 10.57 percent return on equity premised upon a top quartile Discounted Cash Flow (DCF) formula using a two-stage growth rate. Although supporting the incentive return on these projects, the FERC ruling was clear that alternative approaches can be evaluated in other proceedings. The Company has established a reserve pending the outcome of this complaint. Consistent with the FERC ruling, the expectation is that the current MISO complainants will update the analysis and file testimony in the pending complaint proceeding.

9. Legislative & Environmental Matters

Indiana Senate Bill 1

In March 2014, Indiana Senate Bill 1 was signed into law. This legislation phases in a 1.6 percent rate reduction to the Indiana Adjusted Gross Income Tax Rate for corporations over a six year period. Pursuant to this legislation, the tax rate will be lowered by 0.25 percent each year for the first five years and 0.35 percent in year six beginning on July 1, 2016 to the final rate of 4.9 percent effective July 1, 2021. Pursuant to FASB guidance, the Company accounted for the effect of the change in tax law on its deferred taxes in the first quarter of 2014, the period of enactment. The impact was not material to results of operations.

Indiana Senate Bill 251

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

Air Quality

Clean Air Interstate Rule / 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. On December 30, 2011, a reviewing court granted a stay of CSAPR and left CAIR in place pending its review. On August 21, 2012, the court vacated CSAPR and directed the EPA to continue to administer CAIR. In April 2014, the US Supreme Court upheld CSAPR. On June 26, 2014, the EPA asked the federal appeals court to lift the stay of the rule. EPA also asked the court to approve a new deadline schedule for entities that must comply, with the first phase caps starting in 2015 and 2016, and the second phase in 2017. While it is possible that the EPA could further revise the rule prior to implementation, the Company does not anticipate a significant impact from the Supreme Court's decision based upon the investments it has already made in pollution control technology to meet the requirements of CAIR. The Company remains in full compliance with CAIR (see additional information below "Conclusions Regarding Air and Water Regulations").

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. The EPA did not grant blanket compliance extensions, but asserted that states have broad authority to grant one year extensions for individual electric generating units where potential reliability impacts have been demonstrated. Reductions are to be achieved within three years of publication of the final rule in the Federal register (April 2015). Multiple judicial challenges were filed and the EPA agreed to reconsider MATS requirements for new construction, as the requirements are more stringent than those for existing plants. Utilities planning new coal-fired generation had argued standards outlined in the MATS could not be attained even using the best available control technology. The EPA issued its revised emission limits for new construction in March 2013. In April 2014, the U.S. Court of Appeals for the D.C. Circuit rejected various challenges to the rule for existing sources that were brought by industry and state petitioners. The Company continues to proceed with its MATS compliance strategy. This plan is currently before the IURC for approval, and the Company anticipates full compliance by the applicable deadlines.

Notice of Violation for A.B. Brown Power Plant
The Company received a notice of violation (NOV) from the EPA in November 2011 pertaining to its A.B. Brown power plant. The NOV asserts that when the power plant 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. Based on the Company's understanding of the New Source Review provisions in effect when the equipment was installed, it is the Company's position that its SCR project was exempt from such requirements. The Company is currently in discussions with the EPA to resolve this NOV.

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

Water
Section 316(b) of the Clean Water Act requires that generating facilities use the “best technology available” (BTA) to minimize adverse environmental impacts in 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. In April 2009, the U.S. Supreme Court affirmed that the EPA could, but was not required to, consider costs and benefits in making the evaluation as to the best technology available for existing generating facilities. The regulation was remanded to the EPA for further consideration. In March 2011, the EPA released its proposed Section 316(b) regulations. The EPA did not mandate the retrofitting of cooling towers in the proposed regulation, but if finalized, the regulation will leave it to each state to determine whether cooling towers should be required on a case by case basis. A final rule was issued on May 19, 2014. The final rule does not mandate cooling water tower retrofits but requires a 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 Vectren’s facilities. Vectren 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 recovered under Indiana Senate Bill 251 referenced above.

Under the Clean Water Act, EPA sets technology-based guidelines for water discharges from new and existing facilities. 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. 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 and the Company is reviewing the proposal. 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, and other federal air quality standards, the Company obtained authority from the IURC to invest in clean coal technology. Using this authorization, the Company invested approximately $411 million starting in 2001 with the last equipment being placed into service on January 1, 2010. The pollution control equipment included SCR systems, fabric filters, and an SO2 scrubber at its generating facility that is jointly owned with AGC (the Company's portion is 150 MW). 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.

The Company continues to review the sufficiency of its existing pollution control equipment in relation to the requirements described in the MATS Rule, the recent renewal of water discharge permits, and the NOV discussed above. Some operational modifications to the control equipment are likely. The Company is continuing to evaluate potential technologies to address compliance and what the additional costs may be associated with these efforts. Currently, it is expected that the capital costs could be between $70 million and $90 million. Compliance is required by government regulation, and the Company believes that such additional costs, if incurred, should be recoverable under Senate Bill 251 referenced above. On January 17, 2014, the Company filed its request with the IURC seeking approval to upgrade its existing emissions control equipment to comply with the MATS Rule, take steps to address EPA's allegations in the NOV and comply with new mercury limits to the waste water discharge permits at the Culley and Brown generating stations. In that filing, the Company has proposed to defer recovery of the costs until 2020 in order to mitigate the impact on customer rates in the near term.

Coal Ash Waste Disposal & Ash Ponds
In June 2010, the EPA issued proposed regulations affecting the management and disposal of coal combustion products, such as ash generated by the Company’s coal-fired power plants. The proposed rules more stringently regulate these byproducts and would likely increase the cost of operating or expanding existing ash ponds and the development of new ash ponds. The alternatives include regulating coal combustion by-products that are not being beneficially reused as hazardous waste. The EPA did not offer a preferred alternative, but took public comment on multiple alternative regulations. Rules have not been finalized given oversight hearings, congressional interest, and other factors. Recently EPA entered into a consent decree in which it agreed to finalize by December 2014 its determination whether to regulate ash as hazardous waste, or the less stringent solid waste designation.

At this time, the majority of the Company’s ash is being beneficially reused. However, the alternatives proposed would require modification to, or closure of, existing ash ponds. The Company estimates capital expenditures to comply could be as much as $30 million, and such expenditures could exceed $100 million if the most stringent of the alternatives is selected. Annual compliance costs could increase only slightly or be impacted by as much as $5 million. Costs for compliance with these regulations should qualify as federally mandated regulatory requirements and be recoverable under Senate Bill 251 referenced above.

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

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

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

In July 2013, the President announced a Climate Action Plan, which calls on the EPA to finalize the rule for new construction expeditiously, and by June 2014 propose, and by June 2015 finalize, NSPS standards for GHG's for existing electric generating units which would apply to Vectren's power plants. States must have their implementation plans to the EPA no later than June 2016. On June 2, 2014, EPA proposed its rule for states to regulate CO2 emissions from existing electric generating units. The rule, when final, will require states to adopt plans that reduce CO2 emissions by 30% from 2005 levels by 2030. Unlike most rulemakings which allow for a 30 day public comment period, the EPA provided 120 days from publication of the proposal in the Federal Register. The current deadline for public comment is October 16, 2014. The proposal sets state-specific CO2 emission rate-based CO2 goals (measured in lb CO2/MWh or "megawatt hour") and guidelines for the development, submission and implementation of state plans to achieve the state goals. These state-specific goals are calculated based upon 2012 average emission rates aggregated for all fossil fuel-based units in the state. For Indiana, the proposal uses a 2012 emission rate of 1,923 lb CO2/MWh, and sets an interim goal of 1,607 lb CO2/MWh and a final emission goal of 1,531 lb CO2/MWh that must be met by 2030. Under this proposal, these CO2 emission rate goals do not apply directly to individual units, or generating systems. They are state goals. As such, the state must establish a framework that will guide how compliance will be met on a statewide basis. The state's interim or "phase in" goal of 1,607 lb CO2/MWh must be met as averaged over a ten year period (2020 - 2029) with progress toward this goal to be demonstrated for every two rolling calendar years starting in 2020, with the first report due in 2022.

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

With respect to the state of Indiana, the four building blocks that support Indiana's goal are as follows:

(1) Heat rate (HR) improvements of 6% (this is consistently applied to all states);
(2) Increasing the dispatch of existing natural gas baseload generation sources to 70%.
(3) Renewable energy portfolio requirements of 5% (interim) and 7% (final).
(4) Energy efficiency / DSM that results in reductions of 1.5% annually starting in 2020, ending at a sustained 11% by 2030.

Under the proposal, Indiana may choose to implement a program based upon an annual average emission rate target or convert that target rate to a comparable CO2 emission cap. Indiana is the 5th largest carbon emitter in the nation in tons of CO2 produced from electric generation. In 2013, Indiana's electric utilities generated 105.6 million tons of CO2. Vectren's share of that total was 6.3 million, or < 6%. Since 2005, Vectren's emissions of CO2 have declined 23% (on a tonnage basis). These reductions have come from the retirement of FB Culley Unit 1, expiration of municipal contracts, electric conservation and the addition of renewable generation and the installation of more efficient dense pack turbine technology. With respect to CO_2 emission rate, since 2005 Vectren 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%. Vectren's CO_2 emission rate of 1922 lbs/MWh is basically the same as the State's average CO_2 emission rate of 1923 lb CO_2 / MWh.

Impact of Legislative Actions & Other Initiatives is Unknown
If the regulations referenced above are finalized by the EPA, or if legislation requiring reductions in CO2 and other GHG's or legislation mandating a renewable energy portfolio standard is adopted, such regulation could substantially affect both the costs and operating characteristics of the Company's fossil fuel generating plants and natural gas distribution businesses. At this time and in the absence of final legislation or rulemaking, compliance costs and other effects associated with reductions in GHG emissions or obtaining renewable energy sources remain uncertain. The Company has gathered preliminary estimates of the costs to control GHG emissions. A preliminary investigation demonstrated costs to comply would be significant, first with regard to operating expenses and later for capital expenditures as technology becomes available to control GHG emissions. However, these compliance cost estimates were based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. As the EPA moves toward finalization of the NSPS for existing sources and the State of Indiana begins formulation of its state implementation plan, the Company will have more information to enable it to better assess potential compliance costs with a final regulation. Costs to purchase allowances that cap GHG emissions or expenditures made to control emissions or lower carbon emission rates should be considered a federally mandated cost of providing electricity, and as such, the Company believes such costs and expenditures should be recoverable from customers through Senate Bill 251 as referenced above or Senate Bill 29.

Renewables
Senate Bill 251 also established a voluntary clean energy portfolio standard that provides incentives to Indiana electricity suppliers participating in the program. The goal of the program is that by 2025, at least 10 percent of the total electricity obtained by the supplier to meet the energy needs of Indiana retail customers will be provided by clean energy sources, as defined. In advance of a federal portfolio standard and Senate Bill 251, SIGECO received regulatory approval to purchase a 3 MW landfill gas generation facility from a related entity. The facility was purchased in 2009 and is directly connected to the Company's distribution system. 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.

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

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

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

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

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company's utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of June 30, 2014 and December 31, 2013, approximately $4.6 million and $5.7 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

10. 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, 2014		December 31, 2013	
(In millions)	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	$1,257.2	$1,410.5	$1,257.1	$1,317.4
Short-term borrowings	3.7	3.7	28.6	28.6
Cash & cash equivalents	4.9	4.9	8.6	8.6

For the balance sheet dates presented in these financial statements, the Company had no material assets or liabilities recorded at fair value outstanding, and no material assets or liabilities valued using Level 3 inputs.

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

Under current regulatory treatment, call premiums on reacquisition of utility-related long-term debt are generally recovered in customer rates over the life of the refunding issue 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.

11. Impact of Recently Issued Accounting Principles

Revenue Recognition Guidance

In May 2014, the FASB issued new accounting guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for GAAP and IFRS. The amendments in this guidance state that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This new guidance requires improved disclosures to help users of financial statements better understand the nature, amount, timing, and uncertainty of revenue that is recognized. For a public entity, the guidance is effective for annual reporting periods beginning after December 15, 2016, with early adoption not permitted. An entity should apply the amendments in this update retrospectively to each prior reporting period presented or retrospectively with the cumulative effect of initially applying this update recognized at the date of initial application. The Company is currently evaluating the standard to understand the overall impact it will have on the financial statements.

Financial Reporting of Discontinued Operations

In April 2014, the FASB issued new accounting guidance on reporting discontinued operations and disclosures of disposals of a company or entity. The guidance changes the criteria for reporting discontinued operations and provides for enhanced disclosures in this area. Under the new guidance, only disposals representing a strategic shift in operations should be presented as discontinued operations. Those strategic shifts should have a major effect on the organization's operations and financial results. Additionally, the new guidance requires expanded disclosures about discontinued operations to provide more information about the assets, liabilities, income, and expenses of discontinued operations. The new guidance also requires disclosure of the pre-tax income attributable to a disposal of a significant part of an organization that does not qualify for discontinued operations reporting. This guidance is effective for fiscal years beginning on or after December 15, 2014, with early adoption permitted. Adoption of this guidance is not expected to have an impact on the Company's financial statements.

12. 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 is comprised of 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. The presentation for Other Operations and Eliminations revenue for the prior year was overstated by offsetting amounts that had no effect on revenue. The presentation has been revised in the table below:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2014	2013	2014	2013
Revenues				
Gas Utility Services	$132.4	$138.0	$576.0	$453.9
Electric Utility Services	152.0	154.7	315.0	304.2
Other Operations	9.5	9.5	19.1	19.0
Eliminations	(9.4)	(9.4)	(19.0)	(18.8)
Total revenues	$284.5	$292.8	$891.1	$758.3
Profitability Measure - Net Income				
Gas Utility Services	$0.7	$2.9	$39.0	$41.0
Electric Utility Services	19.9	18.9	39.2	33.5
Other Operations	2.3	2.4	6.0	4.8
Total net income	$22.9	$24.2	$84.2	$79.3

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), Southern Indiana Gas and Electric Company (SIGECO), 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 578,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 143,000 electric customers and approximately 111,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to approximately 315,000 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.

Executive Summary of Consolidated Results of Operations

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 2013 annual report filed on Form 10-K.

In the second quarter of 2014, Utility Holdings' earnings were $22.9 million, compared to $24.2 million in 2013. In the six months ended June 30, 2014, Utility Holdings earned $84.2 million, compared to $79.3 million in 2013. The quarter over quarter decrease was primarily related to a $3.1 million increase in operating expenses. The year to date increase is driven by increased electric margins associated with weather, as well as returns from Ohio gas infrastructure replacement programs. These increases, however, have been offset somewhat by increased operating expenses in both the quarter and year to date periods driven by weather-related maintenance stemming from the harsh winter and performance-based compensation expense.

Gas Utility Services

During the second quarter of 2014, Gas Utility Services earned $0.7 million compared to earnings of $2.9 million in the second quarter of 2013. In the six months ended June 30, 2014, Gas Utility Services earnings were $39.0 million, compared to earnings of $41.0 million in 2013. Though customer margin increased in 2014 from small customer growth and the returns from the Ohio infrastructure replacement programs, the increase in margin was offset primarily by higher operating expenses driven by weather-related maintenance of the gas system and by increased performance-based compensation expense. Likewise, the quarter results were negatively impacted by similar higher costs.

Electric Utility Services

During the second quarter of 2014, Electric Utility Services' earnings were $19.9 million, compared to $18.9 million in the second quarter of 2013. Electric Utility Services earned $39.2 million year to date in 2014, compared to earnings of $33.5 million for the six months ended June 30, 2013. The increases in the quarter and year to date periods are driven primarily by the impact of weather on retail electric margin, which management estimates the after tax impact to be approximately $0.9 million in the second quarter of 2014 and $2.2 million favorable year to date, as compared to the 2013 periods. Earnings in the quarter and year to date in 2014 were unfavorably impacted by higher operating expenses due to the timing of power supply maintenance, as well as increased performance-based compensation expense.

Other Utility Operations

In the second quarter of 2014, earnings from Other Utility operations were $2.3 million, compared to $2.4 million in 2013. In the six months ended June 30, 2014, earnings from these operations were $6.0 million compared to $4.8 million in 2013. The increase in the six months ended June 30, 2014 is primarily driven by an increase in interest income and a decrease in interest expense compared to 2013.

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)	2014	2013	2014	2013
Gas utility revenues	$132.4	$138.0	$576.0	$453.9
Cost of gas sold	43.7	50.7	314.6	207.9
Total gas utility margin	$88.7	$87.3	$261.4	$246.0
Margin attributed to:				
Residential & commercial customers	$67.5	$66.5	$190.7	$187.0
Industrial customers	12.1	12.5	30.9	29.8
Other	2.8	2.4	6.4	5.4
Regulatory expense recovery mechanisms	6.3	5.9	33.4	23.8
Total gas utility margin	$88.7	$87.3	$261.4	$246.0
Sold & transported volumes in MMDth attributed to:				
Residential & commercial customers	12.0	12.0	77.6	67.1
Industrial customers	23.7	25.1	59.7	56.1
Total sold & transported volumes	35.7	37.1	137.3	123.2

Gas Utility margins were $88.7 million and $261.4 million for the three and six months ended June 30, 2014, and compared to 2013, increased $1.4 million quarter over quarter and $15.4 million year to date. Year to date, customer margin increased $2.9 million compared to 2013 from small customer growth and large customer usage. Additionally, year to date margin was favorably impacted $1.6 million by returns from infrastructure replacement programs, particularly in Ohio. With rate designs that substantially limit the impact of weather on margin, heating degree days that were 115 percent of normal in Ohio and 110 percent of normal in Indiana during the six months ended June 30, 2014, compared to 103 percent of normal in Ohio and 101 percent of normal in Indiana during 2013, had an approximate $0.4 million favorable impact on small customer margin. Weather was also the primary driver in the higher volumetric pass through costs, which increased $9.6 million year to date compared to the prior year.

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)	2014	2013	2014	2013
Electric utility revenues	$152.0	$154.7	$315.0	$304.2
Cost of fuel & purchased power	48.1	53.9	105.1	104.1
Total electric utility margin	$103.9	$100.8	$209.9	$200.1
Margin attributed to:				
Residential & commercial customers	$64.4	$60.5	$128.7	$121.2
Industrial customers	27.9	27.8	53.9	53.9
Other	1.1	0.9	2.0	1.7
Regulatory expense recovery mechanisms	1.8	2.0	6.6	4.5
Subtotal: retail	$95.2	$91.2	$191.2	$181.3
Wholesale power & transmission system margin	8.7	9.6	18.7	18.8
Total electric utility margin	$103.9	$100.8	$209.9	$200.1
Electric volumes sold in GWh attributed to:				
Residential & commercial customers	658.4	631.2	1,377.5	1,302.5
Industrial customers	692.4	698.0	1,352.5	1,357.3
Other customers	4.9	4.8	10.9	10.6
Total retail volumes sold	1,355.7	1,334.0	2,740.9	2,670.4

Retail
Electric retail utility margins were $95.2 million and $191.2 million for the three and six months ended June 30, 2014, and, compared to 2013, increased by $4.0 million in the quarter and $9.9 million year to date. Electric results are not protected by weather normalizing mechanisms which resulted in a $2.5 million increase in small customer margin as cooling degree days in the second quarter of 2014 were 132 percent of normal compared to 107 percent of normal in 2013. For the year to date period, electric results were positively impacted by weather, resulting in a year to date increase of $5.4 million in small customer margin. Margin from regulatory expense recovery mechanisms increased $2.1 million year to date 2014 compared to 2013 driven primarily by a corresponding increase in operating expenses associated with the electric state-mandated conservation programs. As conservation initiatives continue, in the six months ended June 30, 2014, the Company's lost revenue recovery mechanism contributed increased margin of $2.3 million related to electric conservation programs.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2014	2013	2014	2013

Transmission system margin	$6.6	$7.9	$12.7	$14.5
Off-system margin	2.1	1.7	6.0	4.3
Total wholesale margin	$8.7	$9.6	$18.7	$18.8

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms, and other transmission system operations, totaled $12.7 million and $14.5 million during the six months ended June 30, 2014 and 2013, respectively. During the 2014 second quarter, transmission system margin was $6.6 million compared to $7.9 million for the same period in 2013. As of June 30, 2014, the Company had invested approximately $157.6 million in qualifying projects. The net plant balance for these projects totaled $145.2 million at June 30, 2014. These projects include an interstate 345 Kv transmission line that connects Vectren'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 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, and 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 $106.7 million that earned the FERC approved equity rate of return, including while under construction. The last segment of that project was placed into service in December 2012.

For the six months ended June 30, 2014, margin from off-system sales was $6.0 million, compared to $4.3 million in 2013. In the second quarter of 2014 margin from off system sales was $2.1 million compared to $1.7 million in 2013. 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 an increase primarily related to weather.

Operating Expenses

Other Operating

During the second quarter of 2014, other operating expenses were $81.5 million, an increase of $5.4 million, partially related to the timing of power supply maintenance costs and performance-based compensation. For the six months ended June 30, 2014, other operating expenses were $179.8 million, an increase of $16.9 million, compared to 2013. Costs that are recovered directly in margin account for $8.7 million of the year to date increase. Excluding these pass through costs, other operating expenses increased $8.2 million year to date, compared to the same period in 2013, primarily associated with increased energy delivery expenses due to the harsh winter weather in the first quarter 2014 and increased performance-based compensation expense.

Depreciation & Amortization

In the second quarter of 2014, depreciation and amortization expense was $50.6 million, compared to $48.7 million in 2013. For the six months ended June 30, 2014, depreciation and amortization expense was $100.5 million, which represents an increase of $3.4 million compared to 2013. Both year to date and quarter to date periods reflect increased plant placed into service.

Taxes Other Than Income Taxes

Taxes other than income taxes were $12.5 million for the second quarter of 2014, an increase of $0.3 million, compared to 2013. Year to date, taxes other than income taxes were $32.6 million compared to $29.7 million for the year to date period in 2013. The increase of $2.9 million is primarily due to higher revenue taxes associated with increased consumption and higher gas costs. These taxes are primarily revenue-related taxes and are offset dollar-for-dollar with lower gas utility and electric utility revenues.

Other Income - Net

Other income-net reflects income of $3.7 million for the second quarter of 2014, an increase of $0.7 million, compared to 2013. Year to date, other income-net reflects income of $7.6 million compared to $4.8 million, compared to 2013. Year to date results include increased AFUDC of approximately $2.3 million, driven primarily by higher capital spending.

Rate & Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement
Vectren monitors and maintains its natural gas distribution system to ensure that natural gas is delivered in a safe and efficient manner. Vectren's natural gas utilities are currently engaged in replacement programs in both Indiana and Ohio, to mitigate risk, improve the system, and comply with applicable regulations. Laws in both Indiana and Ohio were passed that provide utilities the opportunity to timely recover costs of federally mandated projects and other infrastructure improvement projects outside of a base rate proceeding.

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 $118 million. Regulatory assets associated with post in service carrying costs and depreciation deferrals were $11.2 million and $9.3 million at June 30, 2014 and December 31, 2013, respectively. Due to the expiration of the initial five year term for the DRR in early 2014, the Company filed a request in August 2013 to extend and expand the DRR. On February 19, 2014, the PUCO approved 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 also approved an adjustment to the bill impact evaluation, limiting the resulting DRR rate 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 $187 million. In addition, the Order approved the Company's commitment that the DRR can only be further extended as part of a base rate case. On May 1, 2014, the Company filed its annual request to adjust the DRR for recovery of costs incurred through December 31, 2013. On July 25, 2014, the PUCO staff completed its audit and recommended approval of the DRR as filed. A hearing in this proceeding is scheduled for August 6, 2014, and an order is expected later in 2014.

In June 2011, Ohio House Bill 95 was signed into law. Outside of a base rate proceeding, this legislation permits a natural gas company 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. On December 12, 2012, the PUCO issued an order approving the Company's initial application under this law, reflecting its capital expenditure program covering the fifteen month period ending December 31, 2012. Such capital expenditures include infrastructure expansion and improvements not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. The order also 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. In addition, the order approved the Company's proposal that subsequent requests for accounting authority will be filed annually in April. The Company submitted its most recent annual filing on April 30, 2014, which covers the Company’s capital expenditure program through calendar year 2014.

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 rate increase limits discussed above are not expected to be reached given this capital expenditure plan during the remaining four year time frame.

Indiana Recovery and Deferral Mechanisms

The Company's Indiana natural gas utilities received orders in 2008 and 2007 associated with the most recent base rate cases. These orders authorized the deferral of financial impacts associated with bare steel and cast iron replacement activities. The orders provide for the deferral of depreciation and post in service carrying costs on qualifying projects totaling $20 million annually at Indiana Gas and $3 million annually at SIGECO. The debt-related post in service carrying costs are recognized in the Condensed

Consolidated Statements of Income currently. The recording of post in service carrying costs and depreciation deferral is limited by individual qualifying project to three years after being placed into service at SIGECO and four years after being placed into service at Indiana Gas. At June 30, 2014 and December 31, 2013, the Company has regulatory assets totaling $14.3 million and $12.1 million, respectively, associated with the deferral of depreciation and debt-related post in service carrying cost activities.

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

In April 2013, Senate Bill 560 was signed into law. This legislation supplements Senate Bill 251 described above, which addressed federally mandated investment, 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 recovery using a periodic rate adjustment mechanism. Recoverable costs include a return on and of the investment, as well as property taxes and operating expenses. The remaining 20 percent of project costs are to be deferred for future recovery in the Company's next general rate case, which must be filed no later than the end of the seven year plan. The adjustment mechanism is capped at an annual increase in retail revenues of no more than two percent.

Pipeline Safety Law
On January 3, 2012, the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (Pipeline Safety Law) was signed into law. The Pipeline Safety Law, which reauthorizes federal pipeline safety programs through fiscal year 2015, provides for enhanced safety, reliability, and environmental protection in the transportation of energy products by pipeline. The law increases federal enforcement authority; grants the federal government expanded authority over pipeline safety; provides for new safety regulations and standards; and authorizes or requires the completion of several pipeline safety-related studies. The DOT is required to promulgate a number of new regulatory requirements over the next two years. Those regulations may eventually lead to further regulatory or statutory requirements.

While the Company continues to study the impact of the Pipeline Safety Law and potential new regulations associated with its implementation, it is expected that the law will result in further investment in pipeline inspections, and where necessary, additional investments in pipeline infrastructure and, therefore, result in both increased levels of operating expenses and capital expenditures associated with the Company's natural gas distribution businesses.

Requests for Recovery Under Indiana Regulatory Mechanisms
The Company filed in November 2013 for authority to recover costs related to its gas infrastructure replacement and improvement programs in Indiana, including costs associated with existing pipeline safety regulations, using the mechanisms allowed under Senate Bill 251 and Senate Bill 560. The combined SIGECO and Indiana Gas filing requests recovery of the capital expenditures associated with the infrastructure replacement and improvement plan pursuant to the legislation, estimated to be approximately $865 million combined, inclusive of an estimated $30 million of possible economic development related expenditures, over the seven year period beginning in 2014. The plan also includes approximately $13 million of combined annual operating costs associated with pipeline safety rules. Intervening parties to the proceeding filed testimony that generally supports the Company's plan and the mechanism for recovery. A hearing in this proceeding was held May 8, 2014, and proposed orders have been filed by all parties. An order is expected in late third quarter of 2014.

SIGECO Electric Environmental Compliance Filing

On January 17, 2014, SIGECO filed a request with the IURC for approval of capital investments estimated to be between $70 million and $90 million on its coal-fired generation units to comply with new EPA mandates related to mercury and air toxin standards effective in 2016 and to address an outstanding Notice of Violation (NOV) from the EPA. Roughly half of the investment will be made to control mercury in both air and water emissions. The remaining investment will be made to address the NOV on alleged increases in sulfur trioxide emissions. Although the Company believes these investments are recoverable as a federally mandated investment under Senate Bill 251, the Company has requested deferred accounting treatment in lieu of timely recovery to avoid immediate customer bill impacts. The accounting treatment request seeks 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 Company filed its case-in-chief on March 14, 2014. Intervening parties filed their testimony on May 28, 2014, to which the Company responded with rebuttal testimony on June 20, 2014. A hearing was held beginning on July 30, 2014. An order is expected in the fourth quarter of 2014.

Coal Procurement Procedures
SIGECO submitted a request for proposal (RFP) in April 2011 regarding coal purchases for a four year period beginning in 2012. After negotiations with bidders, SIGECO reached an agreement in principle for multi-year purchases with two suppliers, one of which was Vectren Fuels, Inc. Consistent with the IURC direction in the Company’s last electric rate case, a sub docket proceeding was established to review the Company’s prospective coal procurement procedures. In March 2012, the IURC issued its order in that sub docket which concluded that SIGECO’s 2011 RFP process resulted in the lowest fuel cost reasonably possible. SIGECO has long term contracts with Vectren Fuels to provide supply for its generating units. Those contracts will be reviewed in a pending sub docket proceeding. A hearing will be held in October 2014. Once the pending sale of Vectren Fuels is closed, Sunrise Coal will assume responsibility for fulfilling those contract obligations. Procuring this coal is part of the Company’s MATS compliance strategy.

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 will be 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, starting February 2014, was $42.4 million, of which $38.9 million remains as of June 30, 2014.

SIGECO Electric Demand Side Management Program Filing
On August 16, 2010, SIGECO filed a petition with the IURC, seeking approval of its proposed electric Demand Side Management (DSM) Programs, recovery of the costs associated with these programs, recovery of lost margins as a result of implementing these programs for large customers, and recovery of performance incentives linked with specific measurement criteria on all programs. The DSM Programs proposed were consistent with a December 9, 2009 order issued by the IURC, which, among other actions, defined long-term conservation objectives and goals of DSM programs for all Indiana electric utilities under a consistent statewide approach. In order to meet these objectives, the IURC order divided the DSM programs into Core and Core Plus programs. Core programs are joint programs required to be offered by all Indiana electric utilities to all customers, and include some for large industrial customers. Core Plus programs are those programs not required specifically by the IURC, but defined by each utility to meet the overall energy savings targets defined by the IURC.

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 discussed earlier. For the six months ended June 30, 2014, the Company recognized Electric revenue of $4.4 million associated with this approved lost margin recovery mechanism.

On March 28, 2014, Senate Bill 340 was signed into law. This legislation ends electric DSM programs on December 31, 2014 that have been conducted to meet the energy savings requirements established in the Commission's 2009 order. The legislation also allows for industrial customers to opt out of participating in energy efficiency programs. As of July 1, 2014, approximately 71 percent of the Company’s eligible industrial load has opted out of participation in the applicable energy efficiency programs. Indiana's Governor has requested that the Commission make new recommendations for energy efficiency programs to be proposed for 2015 and beyond, and has also asked the legislature to consider further legislation requiring some level of utility sponsored energy efficiency programs. The Company has filed a request for Commission approval of a new portfolio of DSM programs on May 29, 2014 to be effective in January 2015. On July 23, 2014, the OUCC and the Company filed a Notice of Settlement regarding the new portfolio with the Commission. A hearing in this proceeding is scheduled for September 3, 2014.

Indiana Gas Pipeline Safety Investigation
On April 11, 2012, the IURC's pipeline safety division filed a complaint against Indiana Gas alleging several violations of safety regulations pertaining to damage that occurred at a residence in Indiana Gas's service territory during a pipeline replacement project. The Company negotiated a settlement with the IURC's pipeline safety division, agreeing to a fine and several modifications to the Company's operating policies. The amount of the fine was not material to the Company's financial results. The IURC approved the settlement but modified certain terms of the settlement and added a requirement that Company employees conduct inspections of pipeline excavations. The Company sought and was granted a request for rehearing on the sole issue related to the requirement to use Company employees to inspect excavations. A settlement in the case was reached between the IURC's pipeline safety division and Indiana Gas that allowed Indiana Gas to continue to use its risk based approach to inspecting excavations and to allow the Company to continue using a mix of highly trained and qualified contractors and employees to perform inspections. On January 15, 2014, the IURC issued a Final Order in the case approving the settlement agreement, without modification.

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 gas companies and recovery of new conservation program costs through December 2015. The order provides that the companies must submit an extension proposal no later than March 1, 2015.

FERC Return on Equity 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. In the event a refund is required upon resolution of the complaint, the parties are seeking a refund calculated as of the filing date of the complaint. The MISO transmission owners filed their response to the complaint on January 6, 2014, opposing any change to the return. In addition to the group response, the Company filed a supplemental response, stating that if FERC allows the complaint to go forward, the complaint should not be applied to the Company's recently completed Gibson-Brown-Reid 345 Kv transmission line investment. As of June 30, 2014, the Company had invested approximately $157.6 million in qualifying projects. The net plant balance for these projects totaled $145.2 million at June 30, 2014.

FERC has no deadline for action. 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. In August 2013, a FERC administrative law judge recommended in that proceeding that the return be lowered to 9.7 percent, retroactive to the date of the complaint filing. On June 19, 2014, the FERC voted to approve an order in this proceeding that allows for a 10.57 percent return on equity premised upon a top quartile Discounted Cash Flow (DCF) formula using a two-stage growth rate. Although supporting the incentive return on these projects, the FERC ruling was clear that alternative approaches can be evaluated in other proceedings. The Company has established a reserve pending the outcome of this complaint. Consistent with the FERC ruling, the expectation is that the current MISO complainants will update the analysis and file testimony in the pending complaint proceeding.

Legislative & Environmental Matters

Indiana Senate Bill 1

In March 2014, Indiana Senate Bill 1 was signed into law. This legislation phases in a 1.6 percent rate reduction to the Indiana Adjusted Gross Income Tax Rate for corporations over a six year period. Pursuant to this legislation, the tax rate will be lowered by 0.25 percent each year for the first five years and 0.35 percent in year six beginning on July 1, 2016 to the final rate of 4.9 percent effective July 1, 2021. Pursuant to FASB guidance, the Company accounted for the effect of the change in tax law on its deferred taxes in the first quarter of 2014, the period of enactment. The impact was not material to results of operations.

Indiana Senate Bill 251

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

Air Quality

Clean Air Interstate Rule / 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. On December 30, 2011, a reviewing court granted a stay of CSAPR and left CAIR in place pending its review. On August 21, 2012, the court vacated CSAPR and directed the EPA to continue to administer CAIR. In April 2014, the US Supreme Court upheld CSAPR. On June 26, 2014, the EPA asked the federal appeals court to lift the stay of the rule. EPA also asked the court to approve a new deadline schedule for entities that must comply, with the first phase caps starting in 2015 and 2016, and the second phase in 2017. While it is possible that the EPA could further revise the rule prior to implementation, the Company does not anticipate a significant impact from the Supreme Court's decision based upon the investments it has already made in pollution control technology to meet the requirements of CAIR. The Company remains in full compliance with CAIR (see additional information below "Conclusions Regarding Air and Water Regulations").

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. The EPA did not grant blanket compliance extensions, but asserted that states have broad authority to grant one year extensions for individual electric generating units where potential reliability impacts have been demonstrated. Reductions are to be achieved within three years of publication of the final rule in the Federal register (April 2015). Multiple judicial challenges were filed and the EPA agreed to reconsider MATS requirements for new construction, as the requirements are more stringent than those for existing plants. Utilities planning new coal-fired generation had argued standards outlined in the MATS could not be attained even using the best available control technology. The EPA issued its revised emission limits for new construction in March 2013. In April 2014, the U.S. Court of Appeals for the D.C. Circuit rejected various challenges to the rule for existing sources that were brought by industry and state petitioners. The Company continues to proceed with its MATS compliance strategy. This plan is currently before the IURC for approval, and the Company anticipates full compliance by the applicable deadlines.

Notice of Violation for A.B. Brown Power Plant

The Company received a notice of violation (NOV) from the EPA in November 2011 pertaining to its A.B. Brown power plant. The NOV asserts that when the power plant 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. Based on the Company's understanding of the New Source Review provisions in effect when the equipment was installed, it is the Company's position that its SCR project was exempt from such requirements. The Company is currently in discussions with the EPA to resolve this NOV.

Information Request

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

Water

Section 316(b) of the Clean Water Act requires that generating facilities use the "best technology available" (BTA) to minimize adverse environmental impacts in 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. In April 2009, the U.S. Supreme Court affirmed that the EPA could, but was not required to, consider costs and benefits in making the evaluation as to the best technology available for existing generating facilities. The regulation was remanded to the EPA for further consideration. In March 2011, the EPA released its proposed Section 316(b) regulations. The EPA did not mandate the retrofitting of cooling towers in the proposed regulation, but if finalized, the regulation will leave it to each state to determine whether cooling towers should be required on a case by case basis. A final rule was issued on May 19, 2014. The final rule does not mandate cooling water tower retrofits but requires a 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 Vectren's facilities. Vectren 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 recovered under Indiana Senate Bill 251 referenced above.

Under the Clean Water Act, EPA sets technology-based guidelines for water discharges from new and existing facilities. 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. 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 and the Company is reviewing the proposal. 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, and other federal air quality standards, the Company obtained authority from the IURC to invest in clean coal technology. Using this authorization, the Company invested approximately $411 million starting in 2001 with the last equipment being placed into service on January 1, 2010. The pollution control equipment included SCR systems, fabric filters, and an SO2 scrubber at its generating facility that is jointly owned with AGC (the Company's portion is 150 MW). 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.

The Company continues to review the sufficiency of its existing pollution control equipment in relation to the requirements described in the MATS Rule, the recent renewal of water discharge permits, and the NOV discussed above. Some operational modifications to the control equipment are likely. The Company is continuing to evaluate potential technologies to address compliance and what the additional costs may be associated with these efforts.

Currently, it is expected that the capital costs could be between $70 million and $90 million. Compliance is required by government regulation, and the Company believes that such additional costs, if incurred, should be recoverable under Senate Bill 251 referenced above. On January 17, 2014, the Company filed its request with the IURC seeking approval to upgrade its existing emissions control equipment to comply with the MATS Rule, take steps to address EPA's allegations in the NOV and comply with new mercury limits to the waste water discharge permits at the Culley and Brown generating stations. In that filing, the Company has proposed to defer recovery of the costs until 2020 in order to mitigate the impact on customer rates in the near term.

Coal Ash Waste Disposal & Ash Ponds

In June 2010, the EPA issued proposed regulations affecting the management and disposal of coal combustion products, such as ash generated by the Company's coal-fired power plants. The proposed rules more stringently regulate these byproducts and would likely increase the cost of operating or expanding existing ash ponds and the development of new ash ponds. The alternatives include regulating coal combustion by-products that are not being beneficially reused as hazardous waste. The EPA did not offer a preferred alternative, but took public comment on multiple alternative regulations. Rules have not been finalized given oversight hearings, congressional interest, and other factors. Recently EPA entered into a consent decree in which it agreed to finalize by December 2014 its determination whether to regulate ash as hazardous waste, or the less stringent solid waste designation.

At this time, the majority of the Company's ash is being beneficially reused. However, the alternatives proposed would require modification to, or closure of, existing ash ponds. The Company estimates capital expenditures to comply could be as much as $30 million, and such expenditures could exceed $100 million if the most stringent of the alternatives is selected. Annual compliance costs could increase only slightly or be impacted by as much as $5 million. Costs for compliance with these regulations should qualify as federally mandated regulatory requirements and be recoverable under Senate Bill 251 referenced above.

Climate Change

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

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

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

In July 2013, the President announced a Climate Action Plan, which calls on the EPA to finalize the rule for new construction expeditiously, and by June 2014 propose, and by June 2015 finalize, NSPS standards for GHG's for existing electric generating units which would apply to Vectren's power plants. States must have their implementation plans to the EPA no later than June 2016. On June 2, 2014, EPA proposed its rule for states to regulate CO_2 emissions from existing electric generating units. The rule, when final, will require states to adopt plans that reduce CO_2 emissions by 30% from 2005 levels by 2030. Unlike most rulemakings which allow for a 30 day public comment period, the EPA provided 120 days from publication of the proposal in the Federal Register. The current deadline for public comment is October 16, 2014. The proposal sets state-specific CO_2 emission rate-based CO_2 goals (measured in lb CO_2/MWh or "megawatt hour") and guidelines for the development, submission and implementation of state plans to achieve the state goals. These state-specific goals are calculated based upon 2012 average emission rates aggregated for all fossil fuel-based units in the state. For Indiana, the proposal uses a 2012 emission rate of 1,923 lb CO_2/MWh, and sets an interim goal of 1,607 lb CO_2/MWh and a final emission goal of 1,531 lb CO_2/MWh that must be met by 2030. Under this proposal, these CO_2 emission rate goals do not apply directly to individual units, or generating systems. They are state goals. As such, the state must establish a framework that will guide how compliance will be met on a statewide basis. The state's interim or "phase in" goal of 1,607 lb CO_2/MWh must be met as averaged over a ten year period (2020 - 2029) with progress toward this goal to be demonstrated for every two rolling calendar years starting in 2020, with the first report due in 2022.

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

With respect to the state of Indiana, the four building blocks that support Indiana's goal are as follows:

(1) Heat rate (HR) improvements of 6% (this is consistently applied to all states);
(2) Increasing the dispatch of existing natural gas baseload generation sources to 70%.
(3) Renewable energy portfolio requirements of 5% (interim) and 7% (final).
(4) Energy efficiency / DSM that results in reductions of 1.5% annually starting in 2020, ending at a sustained 11% by 2030.

Under the proposal, Indiana may choose to implement a program based upon an annual average emission rate target or convert that target rate to a comparable CO2 emission cap. Indiana is the 5th largest carbon emitter in the nation in tons of CO2 produced from electric generation. In 2013, Indiana's electric utilities generated 105.6 million tons of CO2. Vectren's share of that total was 6.3 million, or < 6%. Since 2005, Vectren's emissions of CO2 have declined 23% (on a tonnage basis). These reductions have come from the retirement of FB Culley Unit 1, expiration of municipal contracts, electric conservation and the addition of renewable generation and the installation of more efficient dense pack turbine technology. With respect to CO2 emission rate, since 2005 Vectren has lowered its CO2 emission rate (as measured in lbs CO2 / MWh) from 1967 lbs CO2 / MWh to 1922 lbs CO2 / MWh, for a reduction of 3%. Vectren's CO2 emission rate of 1922 lbs/MWh is basically the same as the State's average CO2 emission rate of 1923 lb CO2 / MWh.

Impact of Legislative Actions & Other Initiatives is Unknown

If the regulations referenced above are finalized by the EPA, or if legislation requiring reductions in CO2 and other GHG's or legislation mandating a renewable energy portfolio standard is adopted, such regulation could substantially affect both the costs and operating characteristics of the Company's fossil fuel generating plants and natural gas distribution businesses. At this time and in the absence of final legislation or rulemaking, compliance costs and other effects associated with reductions in GHG emissions or obtaining renewable energy sources remain uncertain. The Company has gathered preliminary estimates of the costs to control GHG emissions. A preliminary investigation demonstrated costs to comply would be significant, first with regard to operating expenses and later for capital expenditures as technology becomes available to control GHG emissions. However, these compliance cost estimates were based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. As the EPA moves toward finalization of the NSPS for existing sources and the State of Indiana begins formulation of its state implementation plan, the Company will have more information to enable it to better assess potential compliance costs with a final regulation. Costs to purchase allowances that cap GHG emissions or expenditures made to control emissions or lower carbon emission rates should be considered a federally mandated cost of providing electricity, and as such, the Company believes such costs and expenditures should be recoverable from customers through Senate Bill 251 as referenced above or Senate Bill 29.

Renewables
Senate Bill 251 also established a voluntary clean energy portfolio standard that provides incentives to Indiana electricity suppliers participating in the program. The goal of the program is that by 2025, at least 10 percent of the total electricity obtained by the supplier to meet the energy needs of Indiana retail customers will be provided by clean energy sources, as defined. In advance of a federal portfolio standard and Senate Bill 251, SIGECO received regulatory approval to purchase a 3 MW landfill gas generation facility from a related entity. The facility was purchased in 2009 and is directly connected to the Company's distribution system. 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.

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

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

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

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

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company’s utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of June 30, 2014 and December 31, 2013, approximately $4.6 million and $5.7 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

Impact of Recently Issued Accounting Guidance

Revenue Recognition Guidance

In May 2014, the FASB issued new accounting guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for GAAP and IFRS. The amendments in this guidance state that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This new guidance requires improved disclosures to help users of financial statements better understand the nature, amount, timing, and uncertainty of revenue that is recognized. For a public entity, the guidance is effective for annual reporting periods beginning after December 15, 2016, with early adoption not permitted. An entity should apply the amendments in this update retrospectively to each prior reporting period presented or retrospectively with the cumulative effect of initially applying this update recognized at the date of initial application. The Company is currently evaluating the standard to understand the overall impact it will have on the financial statements.

Financial Reporting of Discontinued Operations

In April 2014, the FASB issued new accounting guidance on reporting discontinued operations and disclosures of disposals of a company or entity. The guidance changes the criteria for reporting discontinued operations and provides for enhanced disclosures in this area. Under the new guidance, only disposals representing a strategic shift in operations should be presented as discontinued operations. Those strategic shifts should have a major effect on the organization's operations and financial results. Additionally, the new guidance requires expanded disclosures about discontinued operations to provide more information about the assets, liabilities, income, and expenses of discontinued operations. The new guidance also requires disclosure of the pre-tax income attributable to a disposal of a significant part of an organization that does not qualify for discontinued operations reporting. This guidance is effective for fiscal years beginning on or after December 15, 2014, with early adoption permitted. Adoption of this guidance is not expected to have an impact on the Company's financial statements.

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 outstanding at June 30, 2014 approximated $875 million. As of June 30, 2014, Utility Holdings had $3.7 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, 2014, was approximately $382 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 and Indiana Gas, at June 30, 2014, are A-/A2 as rated by Standard and Poor's Ratings Services (Standard and Poor's) and Moody's Investors Service (Moody's), respectively. The credit ratings on SIGECO's secured debt are A/Aa3. Utility Holdings' commercial paper has a credit rating of A-2/P-1. The current outlook of both Moody's and Standard and Poor's is stable. A security rating is not a recommendation to buy, sell, or hold securities. The rating is subject to revision or withdrawal at any time, and each rating should be evaluated independently of any other rating. Standard and Poor's and Moody's lowest level investment grade rating is BBB- and Baa3, respectively.

The Company's consolidated equity capitalization objective is 50-60 percent of long-term capitalization. This objective may have varied, and will vary, depending on particular business opportunities, capital spending requirements, execution of long-term financing plans, and seasonal factors that affect the Company's operations. The Company's equity component was 54 percent of long-term capitalization at June 30, 2014 and 53 percent at December 31, 2013. 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, 2014, the Company was in compliance with all debt covenants.

Available Liquidity in Current Credit Conditions

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 and modest amounts of incremental long-term debt. However, the resources required for capital investment remain uncertain for a variety of factors including pending legislative and regulatory initiatives involving gas pipeline infrastructure replacement; and 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. The timing and amount of such investments depends on a variety of factors, including available liquidity.

Consolidated Short-Term Borrowing Arrangements

At June 30, 2014, the Company has $350 million of short-term borrowing capacity. As reduced by borrowings currently outstanding, approximately $346 million was available at June 30, 2014. This short-term credit facility was renewed in November 2011 and is available through September 2016. 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)	2014	2013
As of June 30		
Balance Outstanding	$3.7	$124.0
Weighted Average Interest Rate	0.30%	0.34%
Six Months Ended June 30 Average		
Balance Outstanding	$1.3	$105.0
Weighted Average Interest Rate	0.28%	0.36%
Maximum Month End Balance Outstanding	$3.7	$174.8

(In millions)	2014	2013
Quarterly Average - June 30		
Balance Outstanding	$0.6	$146.4
Weighted Average Interest Rate	0.33%	0.35%
Maximum Month End Balance Outstanding	$3.7	$174.8

Potential Uses of Liquidity

Pension Funding Obligations
Vectren's management currently anticipates making no contributions to its qualified pension plans in 2014. As such, Utility Holdings will make no funding contribution to Vectren in 2014.

Other Letters of Credit
As of June 30, 2014, Utility Holdings has letters of credit outstanding in support of two SIGECO tax exempt adjustable rate first mortgage bonds totaling $41.7 million. In the unlikely event the letters of credit were called, the Company could settle with the financial institutions supporting these letters of credit with general assets or by drawing from its credit facility that expires in September 2016. Due to the long-term nature of the credit agreement, such debt is classified as long-term at June 30, 2014.

Planned Capital Expenditures
Utility capital expenditures are estimated at $210 million for the remainder of 2014.

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 $213.2 million and $197.1 million for the six months ended June 30, 2014 and 2013, respectively. The increase was driven primarily by the increase in net income and change in certain working capital accounts.

Financing Cash Flow
Net cash flow required for financing activities was $76.0 million and $95.7 million during the six months ended June 30, 2014 and 2013, respectively. Financing activity in both periods presented reflect the payment of dividends. Decrease in cash flow required for financing activities primarily reflects a greater payoff of short term borrowings in 2014 compared to 2013.

Investing Cash Flow
Cash flow required for investing activities was $140.9 million and $110.8 million during the six months ended June 30, 2014 and 2013, respectively. The increase in cash flow required for investing activities is a result of increased capital expenditures related to gas infrastructure programs.

Forward-Looking Information

A “safe harbor” for forward-looking statements is provided by the Private Securities Litigation Reform Act of 1995 (Reform Act of 1995). The Reform Act of 1995 was adopted to encourage such forward-looking statements without the threat of litigation, provided those statements are identified as forward-looking and are accompanied by meaningful cautionary statements identifying important factors that could cause the actual results to differ materially from those projected in the statement. Certain matters described in Management’s Discussion and Analysis of Results of Operations and Financial Condition are forward-looking statements. Such statements are based on management’s beliefs, as well as assumptions made by and information currently available to management. When used in this filing, the words “believe”, “anticipate”, “endeavor”, “estimate”, “expect”, “objective”, “projection”, “forecast”, “goal”, “likely”, and expressions are intended to identify forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements, factors that could cause the Company's actual results to differ materially from those contemplated in any forward-looking statements include, among others, the following:

- Factors affecting utility operations such as unusual weather conditions; catastrophic weather-related damage; unusual maintenance or repairs; unanticipated changes to coal and natural gas costs; unanticipated changes to gas transportation and storage costs, or availability due to higher demand, shortages, transportation problems or other developments; environmental or pipeline incidents; transmission or distribution incidents; unanticipated changes to electric energy supply costs, or availability due to demand, shortages, transmission problems or other developments; or electric transmission or gas pipeline system constraints.

- Catastrophic events such as fires, earthquakes, explosions, floods, ice storms, tornadoes, terrorist acts, cyber attacks, or other similar occurrences could adversely affect Vectren's facilities, operations, financial condition and results of operations.
- 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 traditional regulation, and the frequency and timing of rate increases.
- Financial, regulatory or accounting principles or policies imposed by the Financial Accounting Standards Board; the Securities and Exchange Commission; the Federal Energy Regulatory Commission; state public utility commissions; state entities which regulate electric and natural gas transmission and distribution, natural gas gathering and processing, electric power supply; and similar entities with regulatory oversight.
- Economic conditions including the effects of inflation rates, commodity prices, and monetary fluctuations.
- Economic conditions surrounding the current economic uncertainty, including increased potential for lower levels of economic activity; uncertainty regarding energy prices and the capital and commodity markets; volatile changes in the demand for natural gas, 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.
- Changing market conditions and a variety of other factors associated with physical energy and financial trading activities including, but not limited to, price, basis, credit, liquidity, volatility, capacity, interest rate, and warranty risks.
- Direct or indirect effects on the Company's business, financial condition, liquidity and results of operations resulting from changes in credit ratings, changes in interest rates, and/or changes in market perceptions of the utility industry and other energy-related industries.
- Employee or contractor workforce factors including changes in key executives, collective bargaining agreements with union employees, aging workforce issues, work stoppages, or pandemic illness.
- Risks associated with material business transactions such as mergers, 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 state and federal 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 performance of projects undertaken by Vectren's nonutility businesses and the success of efforts to realize value from, invest in and develop new opportunities, including but not limited to, Vectren's infrastructure services, energy services, and coal mining, and remaining energy marketing assets.

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 & 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. 2013 Form 10-K and is therefore not presented herein.

ITEM 4. CONTROLS & PROCEDURES

Changes in Internal Controls over Financial Reporting

During the quarter ended June 30, 2014, there have been no changes to the Company’s internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of June 30, 2014, the Company conducted an evaluation under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer of the effectiveness and the design and operation of the Company's disclosure controls and procedures. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective as of June 30, 2014, to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is:

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

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.

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 2013 Form 10-K and are therefore not presented herein.

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

Not Applicable

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not Applicable

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

ITEM 5. OTHER INFORMATION

Not Applicable

ITEM 6. EXHIBITS

Exhibits and Certifications

31.1 Certification Pursuant To Section 302 of The Sarbanes-Oxley Act Of 2002- Chief Executive Officer

31.2 Certification Pursuant To Section 302 of The Sarbanes-Oxley Act Of 2002- Chief Financial Officer

32 Certification Pursuant To Section 906 of The Sarbanes-Oxley Act Of 2002

101 Interactive Data File.

101.INS XBRL Instance Document

101.SCH XBRL Taxonomy Extension Schema

101.CAL XBRL Taxonomy Extension Calculation Linkbase

101.DEF XBRL Taxonomy Extension Definition Linkbase

101.LAB XBRL Taxonomy Extension Labels Linkbase

101.PRE XBRL Taxonomy Extension Presentation Linkbase

SIGNATURES

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

	VECTREN UTILITY HOLDINGS, INC. Registrant
August 11, 2014	/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)