VECTREN UTILITY HOLDINGS INC
Form 10-Q
May 09, 2018

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

FORM 10-Q

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

For the quarterly period ended March 31, 2018
OR

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

For the transition period from __________________ to __________________

Commission file number: 1-16739

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

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

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

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

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

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

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

Large accelerated filer o   Accelerated filer o
Non-accelerated filer ý (Do not check if a smaller reporting company)   Smaller reporting company o
Emerging Growth Company o

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards pursuant to Section 13(a) of the Exchange Act. 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	April 30, 2018
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:	Phone Number:	Investor Relations Contact:
One Vectren Square Evansville, Indiana 47708	(812) 491-4000	David E. Parker Director, Investor Relations vvcir@vectren.com

Definitions

The Administration: Executive Office of the President of the United States	IRP: Integrated Resource Plan
AFUDC: allowance for funds used during construction	IURC: Indiana Utility Regulatory Commission
ASC: Accounting Standards Codification	kV: Kilovolt
ASU: Accounting Standards Update	MCF / BCF: thousands / billions of cubic feet
BTU / MMBTU: British thermal units / millions of BTU	MDth / MMDth: thousands / millions of dekatherms
DOT: Department of Transportation	MISO: Midcontinent Independent System Operator
EPA: Environmental Protection Agency	MW: megawatts
FAC: Fuel Adjustment Clause	MWh / GWh: megawatt hours / thousands of megawatt hours (gigawatt hours)

FASB: Financial Accounting Standards Board

FERC: Federal Energy Regulatory Commission

GAAP: Generally Accepted Accounting Principles
GCA: Gas Cost Adjustment
IDEM: Indiana Department of Environmental Management

OUCC: Indiana Office of the Utility Consumer Counselor

PHMSA: Pipeline and Hazardous Materials Safety Administration
PUCO: Public Utilities Commission of Ohio
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)

	March 31, 2018	December 31, 2017
ASSETS		
Current Assets		
Cash & cash equivalents	$ 14.5	$ 9.8
Accounts receivable - less reserves of $5.2 & $3.9, respectively	116.6	109.5
Accrued unbilled revenues	86.7	123.7
Inventories	96.8	117.5
Recoverable fuel & natural gas costs	11.1	19.2
Prepayments & other current assets	13.3	32.7
Total current assets	339.0	412.4
Utility Plant		
Original cost	7,105.8	7,015.4
Less: accumulated depreciation & amortization	2,770.3	2,738.7
Net utility plant	4,335.5	4,276.7
Investments in unconsolidated affiliates	0.2	0.2
Other investments	26.5	26.7
Nonutility plant - net	203.2	198.6
Goodwill	205.0	205.0
Regulatory assets	315.9	314.0
Other assets	65.9	64.2
TOTAL ASSETS	$ 5,491.2	$ 5,497.8

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)

	March 31, 2018	December 31, 2017
LIABILITIES & SHAREHOLDER'S EQUITY		
Current Liabilities		
Accounts payable	$ 144.5	$ 221.8
Payables to other Vectren companies	28.5	33.3
Accrued liabilities	178.3	154.0
Short-term borrowings	180.4	179.5
Current maturities of long-term debt	100.0	100.0
Total current liabilities	631.7	688.6
Long-Term Debt - Net of Current Maturities	1,479.3	1,479.5
Deferred Credits & Other Liabilities		
Deferred income taxes	458.5	457.5
Regulatory liabilities	954.9	937.2
Deferred credits & other liabilities	200.1	212.2
Total deferred credits & other liabilities	1,613.5	1,606.9
Commitments & Contingencies (Notes 9 - 12)		
Common Shareholder's Equity		
Common stock (no par value)	879.0	877.5
Retained earnings	887.7	845.3
Total common shareholder's equity	1,766.7	1,722.8
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$ 5,491.2	$ 5,497.8

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

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

	Three Months Ended March 31,	
	2018	2017
OPERATING REVENUES		
Gas utility	$329.3	$292.8
Electric utility	134.0	132.1
Other	0.1	0.1
Total operating revenues	463.4	425.0
OPERATING EXPENSES		
Cost of gas sold	145.2	112.9
Cost of fuel & purchased power	42.2	41.2
Other operating	94.8	85.6
Depreciation & amortization	61.0	57.4
Taxes other than income taxes	19.2	14.4
Total operating expenses	362.4	311.5
OPERATING INCOME	101.0	113.5
Other income - net	8.8	7.0
Interest expense	19.9	17.6
INCOME BEFORE INCOME TAXES	89.9	102.9
Income taxes	15.6	37.0
NET INCOME	$74.3	$65.9

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

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

	Three Months Ended March 31,	
	2018	2017
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$74.3	$65.9
Adjustments to reconcile net income to cash from operating activities:		
Depreciation & amortization	61.0	57.4
Deferred income taxes & investment tax credits	(2.3)	25.1
Expense portion of pension & postretirement benefit cost	(1.1)	0.9
Provision for uncollectible accounts	2.4	2.0
Other non-cash items - net	2.6	(0.1)
Changes in working capital accounts:		
Accounts receivable & accrued unbilled revenues	27.5	41.0
Inventories	20.7	13.1
Recoverable/refundable fuel & natural gas costs	8.1	2.8
Prepayments & other current assets	19.0	16.6
Accounts payable, including to Vectren companies & affiliated companies	(78.8)	(56.7)
Accrued liabilities	24.3	26.4
Cash to fund pension plans	(4.8)	—
Changes in noncurrent assets	3.0	(5.5)
Changes in noncurrent liabilities	1.9	(1.9)
Net cash from operating activities	157.8	187.0
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from:		
Additional capital contribution	1.6	41.5
Long-term debt - net of issuance costs	(1.1)	—
Requirements for dividends to parent	(32.0)	(30.5)
Net change in short-term borrowings	0.9	(93.0)
Net cash from financing activities	(30.6)	(82.0)
CASH FLOWS FROM INVESTING ACTIVITIES		
Requirements for:		
Capital expenditures, excluding AFUDC equity	(122.5)	(108.5)
Changes in restricted cash	—	0.9
Net cash from investing activities	(122.5)	(107.6)
Net change in cash & cash equivalents	4.7	(2.6)
Cash & cash equivalents at beginning of period	9.8	9.4
Cash & cash equivalents at end of period	$14.5	$6.8

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 or the Company's parent) three operating public utilities: Indiana Gas Company, Inc. (Indiana Gas or Vectren Energy Delivery of Indiana - North), Southern Indiana Gas and Electric Company (SIGECO or Vectren Energy Delivery of Indiana - South), and Vectren Energy Delivery of Ohio, Inc. (VEDO). Herein, 'the Company' may also refer to Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Inc. and/or Vectren Energy Delivery of Ohio, Inc. The Company 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 the Company are holding companies as defined by the Energy Policy Act of 2005 (Energy Act).

Indiana Gas provides energy delivery services to approximately 603,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 146,000 electric customers and approximately 112,000 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 323,000 natural gas customers located near Dayton in west-central Ohio.

Merger with CenterPoint Energy, Inc.
On April 21, 2018, Vectren entered into an Agreement and Plan of Merger (the “Merger Agreement”), with CenterPoint Energy, Inc., a Texas corporation (“CenterPoint”), and Pacer Merger Sub, Inc., an Indiana corporation and wholly owned subsidiary of CenterPoint (“Merger Sub”). Pursuant to the Merger Agreement, and subject to the terms and conditions of the agreement, Merger Sub will merge with and into Vectren (the “Merger”), with Vectren continuing as the surviving corporation and becoming a wholly owned subsidiary of CenterPoint.

Subject to the terms and conditions in the Merger Agreement, upon closing, each share of common stock of Vectren shall be converted into the right to receive $72.00 in cash without interest.
Vectren, CenterPoint and Merger Sub each have made various representations, warranties and covenants in the Merger Agreement. Among other things, Vectren has agreed, subject to certain exceptions, to conduct its businesses in the ordinary course, consistent with past practice, from the date of the Merger Agreement until closing, and not to take certain actions prior to the closing of the Merger without the approval of CenterPoint. Vectren has made certain additional customary covenants, including, subject to certain exceptions: (1) to cause a meeting of the Company’s parent's shareholders to be held to consider approval of the Merger Agreement, (2) not to solicit proposals relating to alternative business combination transactions and not to participate in discussions concerning, or furnish information in connection with, alternative business combination transactions and (3) not to withdraw its recommendation to the Company’s parent shareholders regarding the Merger. In addition, subject to the terms of the Merger Agreement, Vectren, CenterPoint and Merger Sub are required to use reasonable best efforts to obtain all required regulatory approvals, which will include clearance under federal antitrust laws and certain approvals by federal regulatory bodies, including FERC, subject to certain exceptions, including that such efforts not result in a "Burdensome Condition" (as defined in the Merger Agreement). While approval of the Merger Agreement is not required by the Indiana Utility Regulatory Commission ("IURC") or the Public Utilities Commission of Ohio ("PUCO"),

informational filings will be made with each commission.

Consummation of the Merger is subject to various conditions, including: (1) approval of the shareholders of Vectren, (2) expiration or termination of the applicable Hart-Scott-Rodino Act waiting period, (3) receipt of all required regulatory and statutory approvals without the imposition of a "Burdensome Condition," (4) absence of any law or order prohibiting the consummation of the Merger and (5) other customary closing conditions, including (a) subject to materiality qualifiers, the accuracy of each party's representations and warranties, (b) each party's compliance in all material respects with its

obligations and covenants under the Merger Agreement and (c) the absence of a material adverse effect with respect to Vectren and its subsidiaries.
The Merger Agreement contains certain termination rights for both Vectren and CenterPoint, including if the Merger is not consummated by April 21, 2019 (subject to extension for an additional six months if all of the conditions to closing, other than the conditions related to obtaining regulatory approvals, have been satisfied). The Merger Agreement also provides for certain termination rights for each Vectren and CenterPoint, and provides that, upon termination of the Merger Agreement under certain specified circumstances, CenterPoint would be required to pay a termination fee of $210 million to Vectren, and under other specified circumstances Vectren would be required to pay CenterPoint a termination fee of $150 million.

2. Basis of Presentation

The interim condensed consolidated financial statements included in this report have been prepared by the Company, without audit, as provided in the rules and regulations of the Securities and Exchange Commission and include a review of subsequent events through the date the financial statements were issued. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been omitted as provided in such rules and regulations. The information in this report reflects all adjustments which are, in the opinion of management, necessary to fairly state the interim periods presented, inclusive of adjustments that are normal and recurring in nature. These interim condensed consolidated financial statements and related notes should be read in conjunction with the Company's audited annual consolidated financial statements for the year ended December 31, 2017, filed with the Securities and Exchange Commission on March 8, 2018, 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. Revenue

In May 2014, the FASB issued new accounting guidance, ASC 606, Revenue from Contracts with Customers, to clarify the principles for recognizing revenue and to develop a common revenue standard for GAAP. The amendments in this guidance state 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 enhanced disclosures to help users of financial statements better understand the nature, amount, timing, and uncertainty of revenue that is recognized.

On January 1, 2018, the Company adopted the new accounting standard and all the related amendments ("new revenue standard") to all contracts not complete at the date of initial application using the modified retrospective method, which resulted in no cumulative adjustment to retained earnings. The Company expects ongoing application to continue to be immaterial to financial condition and net income. The comparative information has not been restated and continues to be reported under the accounting standards in effect for those periods.

Substantially all the Company's revenues are within the scope of the new revenue standard.

Revenue Policy

Revenue is recognized when obligations under the terms of a contract with the customer are satisfied. Revenue is measured as the amount of consideration the Company expects to receive in exchange for transferring goods or providing services. The satisfaction of performance obligation occurs when the transfer of goods and services occur, which may be at a point in time or over time; resulting in revenue being recognized over the course of the underlying contract or at a single point in time based upon the delivery of services to customers. The Company determines that disaggregating revenue into customer class, as discussed further below, achieves the disclosure objective to depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors.

The Company provides commodity service to customers at rates, charges, and terms and conditions included in tariffs approved by regulators. The Company’s utilities bill customers on a monthly basis and have the right to consideration from customers in an amount that corresponds directly with the performance obligation satisfied to date. The performance obligation is satisfied and revenue is recognized upon the delivery of services to customers. The Company records revenues for services and goods delivered but not billed at the end of an accounting period in Accrued unbilled revenues, derived from estimated unbilled consumption and tariff rates. The Company's revenues are also adjusted for the effects of regulation including tracked operating expenses, infrastructure replacement mechanisms, decoupling mechanisms, and lost margin recovery. Decoupling and lost margin recovery mechanisms are considered alternative revenue programs, which are excluded from the scope of the new revenue standard. Revenues from alternative revenue programs are not material to any reporting period. Customers are billed monthly and payment terms, set by the regulator, require payment within a month of billing. The Company's revenues are not subject to significant returns, refunds, or warranty obligations.

In the following table, the Company's revenue is disaggregated by customer class.

(In millions)	Three Months Ended March 31, 2018
Gas Utility Services	
Residential	$ 219.7
Commercial	82.6
Industrial	23.8
Other	3.2
Total Gas Utility Services	$ 329.3
Electric Utility Services	
Residential	$ 49.7
Commercial	34.5
Industrial	37.3
Other	12.5
Total Electric Utility Services	$ 134.0

Contract Balances

The Company does not have any material contract balances (right to consideration for services already provided or obligations to provide services in the future for consideration already received) as of January 1, 2018 or March 31, 2018. Substantially all of the Company's accounts receivable results from contracts with customers.

Remaining Performance Obligations

In accordance with the optional exemptions available under the new revenue standard, the Company has not disclosed the value of unsatisfied performance obligations from contracts for which revenue is recognized at the amount to which the Company has the right to invoice for goods provided and services performed. Substantially all of the Company's contracts with customers are eligible for this exemption.

4. Subsidiary Guarantor and Consolidating Information

The Company’s three operating utility companies, SIGECO, Indiana Gas, and VEDO, are guarantors of the Company's $400 million in short-term credit facilities, of which $180 million was outstanding at March 31, 2018, and the Company's $1.195 billion in unsecured senior notes outstanding at March 31, 2018. The guarantees are full and unconditional and joint and several, and the Company has no subsidiaries other than the subsidiary guarantors. However, it 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 wholly owned, separate from the parent company’s operations is required. Following are condensed consolidating financial statements including information on the combined operations of the subsidiary guarantors separate from the other operations of the parent company. Pursuant to a tax sharing agreement, consolidating tax effects, which are calculated on a separate return basis, are reflected at the parent level.

Condensed Consolidating Balance Sheet as of March 31, 2018 (in millions):

ASSETS	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Assets				
Cash & cash equivalents	$ 8.8	$ 5.7	$ —	$ 14.5
Accounts receivable - less reserves	116.3	0.3	—	116.6
Intercompany receivables	82.6	276.3	(358.9)	—
Accrued unbilled revenues	86.7	—	—	86.7
Inventories	96.8	—	—	96.8
Recoverable fuel & natural gas costs	11.1	—	—	11.1
Prepayments & other current assets	10.7	7.1	(4.5)	13.3
Total current assets	413.0	289.4	(363.4)	339.0
Utility Plant				
Original cost	7,105.4	0.4	—	7,105.8
Less: accumulated depreciation & amortization	2,770.3	—	—	2,770.3
Net utility plant	4,335.1	0.4	—	4,335.5
Investments in consolidated subsidiaries	—	1,784.0	(1,784.0)	—
Notes receivable from consolidated subsidiaries	—	970.7	(970.7)	—
Investments in unconsolidated affiliates	0.2	—	—	0.2
Other investments	26.1	0.4	—	26.5
Nonutility plant - net	1.6	201.6	—	203.2
Goodwill - net	205.0	—	—	205.0
Regulatory assets	300.7	15.2	—	315.9
Other assets	64.1	1.8	—	65.9
TOTAL ASSETS	$ 5,345.8	$ 3,263.5	$ (3,118.1)	$ 5,491.2

LIABILITIES & SHAREHOLDER'S EQUITY	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Liabilities				
Accounts payable	$ 137.9	$ 6.6	$ —	$ 144.5
Intercompany payables	25.1	0.1	(25.2)	—
Payables to other Vectren companies	28.5	—	—	28.5
Accrued liabilities	161.0	21.8	(4.5)	178.3
Short-term borrowings	—	180.4	—	180.4
Intercompany short-term borrowings	152.2	82.5	(234.7)	—
Current maturities of long-term debt	—	100.0	—	100.0
Current maturities of long-term debt due to VUHI	99.0	—	(99.0)	—
Total current liabilities	603.7	391.4	(363.4)	631.7
Long-Term Debt				
Long-term debt	384.1	1,095.2	—	1,479.3
Long-term debt due to VUHI	970.7	—	(970.7)	—
Total long-term debt - net	1,354.8	1,095.2	(970.7)	1,479.3
Deferred Credits & Other Liabilities				
Deferred income taxes	450.9	7.6	—	458.5
Regulatory liabilities	953.8	1.1	—	954.9
Deferred credits & other liabilities	198.6	1.5	—	200.1
Total deferred credits & other liabilities	1,603.3	10.2	—	1,613.5

Common Shareholder's Equity				
Common stock (no par value)	892.3	879.0	(892.3)	879.0
Retained earnings	891.7	887.7	(891.7)	887.7
Total common shareholder's equity	1,784.0	1,766.7	(1,784.0)	1,766.7
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$ 5,345.8	$ 3,263.5	$ (3,118.1)	$ 5,491.2

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Condensed Consolidating Balance Sheet as of December 31, 2017 (in millions):

ASSETS	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Assets				
Cash & cash equivalents	$ 8.2	$ 1.6	$ —	$ 9.8
Accounts receivable - less reserves	109.2	0.3	—	109.5
Intercompany receivables	—	227.5	(227.5)	—
Accrued unbilled revenues	123.7	—	—	123.7
Inventories	117.5	—	—	117.5
Recoverable fuel & natural gas costs	19.2	—	—	19.2
Prepayments & other current assets	28.9	12.6	(8.8)	32.7
Total current assets	406.7	242.0	(236.3)	412.4
Utility Plant				
Original cost	7,015.4	—	—	7,015.4
Less: accumulated depreciation & amortization	2,738.7	—	—	2,738.7
Net utility plant	4,276.7	—	—	4,276.7
Investments in consolidated subsidiaries	—	1,741.0	(1,741.0)	—
Notes receivable from consolidated subsidiaries	—	970.7	(970.7)	—
Investments in unconsolidated affiliates	0.2	—	—	0.2
Other investments	26.3	0.4	—	26.7
Nonutility plant - net	1.6	197.0	—	198.6
Goodwill - net	205.0	—	—	205.0
Regulatory assets	298.7	15.3	—	314.0
Other assets	62.5	1.8	(0.1)	64.2
TOTAL ASSETS	$ 5,277.7	$ 3,168.2	$ (2,948.1)	$ 5,497.8

LIABILITIES & SHAREHOLDER'S EQUITY	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Liabilities				
Accounts payable	$ 179.4	$ 42.4	$ —	$ 221.8
Intercompany payables	8.3	—	(8.3)	—
Payables to other Vectren companies	25.2	8.1	—	33.3
Accrued liabilities	147.7	15.1	(8.8)	154.0
Short-term borrowings	—	179.5	—	179.5
Intercompany short-term borrowings	120.2	—	(120.2)	—
Current maturities of long-term debt	—	100.0	—	100.0
Current maturities of long-term debt due to VUHI	99.0	—	(99.0)	—
Total current liabilities	579.8	345.1	(236.3)	688.6
Long-Term Debt				
Long-term debt - net of current maturities & debt subject to tender	384.5	1,095.0	—	1,479.5
Long-term debt due to VUHI	970.7	—	(970.7)	—
Total long-term debt - net	1,355.2	1,095.0	(970.7)	1,479.5
Deferred Credits & Other Liabilities				
Deferred income taxes	455.3	2.2	—	457.5
Regulatory liabilities	936.1	1.1	—	937.2
Deferred credits & other liabilities	210.3	2.0	(0.1)	212.2

Total deferred credits & other liabilities	1,601.7	5.3	(0.1)	1,606.9
Common Shareholder's Equity				
Common stock (no par value)	890.7	877.5	(890.7)	877.5
Retained earnings	850.3	845.3	(850.3)	845.3
Total common shareholder's equity	1,741.0	1,722.8	(1,741.0)	1,722.8
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$ 5,277.7	$ 3,168.2	$ (2,948.1)	$ 5,497.8

Condensed Consolidating Statement of Income for the three months ended March 31, 2018 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	$ 329.3	$ —	$ —	$ 329.3
Electric utility	134.0	—	—	134.0
Other	—	11.8	(11.7)	0.1
Total operating revenues	463.3	11.8	(11.7)	463.4
OPERATING EXPENSES				
Cost of gas sold	145.2	—	—	145.2
Cost of fuel & purchased power	42.2	—	—	42.2
Other operating	106.3	—	(11.5)	94.8
Depreciation & amortization	54.2	6.8	—	61.0
Taxes other than income taxes	18.7	0.5	—	19.2
Total operating expenses	366.6	7.3	(11.5)	362.4
OPERATING INCOME	96.7	4.5	(0.2)	101.0
Other income - net	8.4	13.9	(13.5)	8.8
Interest expense	18.5	15.1	(13.7)	19.9
INCOME BEFORE INCOME TAXES	86.6	3.3	—	89.9
Income taxes	16.6	(1.0)	—	15.6
Equity in earnings of consolidated companies, net of tax	—	70.0	(70.0)	—
NET INCOME	$ 70.0	$ 74.3	$ (70.0)	$ 74.3

Condensed Consolidating Statement of Income for the three months ended March 31, 2017 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	$ 292.8	$ —	$ —	$ 292.8
Electric utility	132.1	—	—	132.1
Other	—	11.4	(11.3)	0.1
Total operating revenues	424.9	11.4	(11.3)	425.0
OPERATING EXPENSES				
Cost of gas sold	112.9	—	—	112.9
Cost of fuel & purchased power	41.2	—	—	41.2
Other operating	96.7	—	(11.1)	85.6
Depreciation & amortization	51.1	6.3	—	57.4
Taxes other than income taxes	13.9	0.5	—	14.4
Total operating expenses	315.8	6.8	(11.1)	311.5
OPERATING INCOME	109.1	4.6	(0.2)	113.5
Other income - net	6.7	12.2	(11.9)	7.0
Interest expense	16.9	12.8	(12.1)	17.6
INCOME BEFORE INCOME TAXES	98.9	4.0	—	102.9
Income taxes	37.4	(0.4)	—	37.0

Equity in earnings of consolidated companies, net of tax	—	61.5	(61.5)	—
NET INCOME	$ 61.5	$ 65.9	$ (61.5)	$ 65.9

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Condensed Consolidating Statement of Cash Flows for the three months ended March 31, 2018 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH PROVIDED BY OPERATING ACTIVITIES	$ 189.4	$ (31.6)	$ —	$ 157.8
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from				
Additional capital contribution from parent	1.6	1.6	(1.6)	1.6
Long-term debt - net of issuance costs	(1.1)	—	—	(1.1)
Requirements for:				
Dividends to parent	(28.6)	(32.0)	28.6	(32.0)
Net change in intercompany short-term borrowings	32.0	82.5	(114.5)	—
Net change in short-term borrowings	—	0.9	—	0.9
Net cash used in financing activities	3.9	53.0	(87.5)	(30.6)
CASH FLOWS FROM INVESTING ACTIVITIES				
Proceeds from:				
Consolidated subsidiary distributions	—	28.6	(28.6)	—
Requirements for:				
Capital expenditures, excluding AFUDC equity	(110.2)	(12.3)	—	(122.5)
Consolidated subsidiary investments	—	(1.6)	1.6	—
Net change in short-term intercompany notes receivable	(82.5)	(32.0)	114.5	—
Net cash used in investing activities	(192.7)	(17.3)	87.5	(122.5)
Net change in cash & cash equivalents	0.6	4.1	—	4.7
Cash & cash equivalents at beginning of period	8.2	1.6	—	9.8
Cash & cash equivalents at end of period	$ 8.8	$ 5.7	$ —	$ 14.5

Condensed Consolidating Statement of Cash Flows for the three months ended March 31, 2017 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH PROVIDED BY OPERATING ACTIVITIES	$ 176.0	$ 11.0	$ —	$ 187.0
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from:				
Additional capital contribution from parent	1.5	41.5	(1.5)	41.5
Requirements for:				
Dividends to parent	(18.3)	(30.5)	18.3	(30.5)
Net change in intercompany short-term borrowings	(51.2)	13.4	37.8	—
Net change in short-term borrowings	—	(93.0)	—	(93.0)
Net cash used in financing activities	(68.0)	(68.6)	54.6	(82.0)
CASH FLOWS FROM INVESTING ACTIVITIES				
Proceeds from:				
Consolidated subsidiary distributions	—	18.3	(18.3)	—
Requirements for:				
Capital expenditures, excluding AFUDC equity	(96.6)	(11.9)	—	(108.5)
Consolidated subsidiary investments	—	(1.5)	1.5	—
Changes in restricted cash	0.9	—	—	0.9
Net change in short-term intercompany notes receivable	(13.4)	51.2	(37.8)	—

Net cash used in investing activities	(109.1)	56.1	(54.6)	(107.6)
Net change in cash & cash equivalents	(1.1)	(1.5)	—	(2.6)
Cash & cash equivalents at beginning of period	7.6	1.8	—	9.4
Cash & cash equivalents at end of period	$ 6.5	$ 0.3	$ —	$ 6.8

5. 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 billed to customers, which totaled $10.5 million and $9.4 million in the three months ended March 31, 2018 and 2017, respectively, as a component of operating revenues. Expenses associated with excise and utility receipts taxes are recorded as a component of Taxes other than income taxes.

6. Supplemental Cash Flow Information

As of March 31, 2018 and December 31, 2017, the Company had accruals related to utility and nonutility plant purchases totaling approximately $23.0 million and $27.4 million, respectively.

7. Transactions with Other Vectren Companies and Affiliates

Vectren Infrastructure Services Corporation (VISCO)
VISCO, a wholly owned subsidiary of the Company's parent, provides underground pipeline construction and repair services. VISCO's customers include the Company's utilities and fees incurred by the Company totaled $24.6 million and $25.8 million for the three months ended March 31, 2018 and 2017, respectively. Amounts owed to VISCO at March 31, 2018 and December 31, 2017 are included in Payables to other Vectren companies in the Condensed Consolidated Balance Sheets.

Support Services & Purchases
The Company's parent provides corporate and general and administrative services to the Company and allocates certain costs to the Company, including costs for share-based compensation and for pension and other postretirement benefits that are not directly charged to subsidiaries. These costs are allocated using various allocators, including number of employees, number of customers and/or the level of payroll, revenue contribution and capital expenditures. Allocations are at cost. For the three months ended March 31, 2018 and 2017, the company received corporate allocations totaling $14.3 million and $16.9 million, respectively.

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

Income Taxes
On December 22, 2017, the United States government enacted comprehensive tax legislation commonly referred to as the Tax Cuts and Jobs Act (“TCJA”). The TCJA makes broad and complex changes to the Internal Revenue Code (“IRC”), many of which were effective on January 1, 2018, including, but not limited to, (1) reducing the Federal corporate income tax rate from 35 percent to 21 percent, (2) eliminating the use of bonus depreciation for regulated utilities, while permitting full expensing of qualified property for non-regulated entities, (3) eliminating the domestic production activities deduction previously allowable under Section 199 of the IRC, (4) creating a new limitation on the deductibility of interest expense for non-regulated businesses, (5) eliminating the corporate Alternative Minimum Tax (“AMT”) and changing how existing AMT credits can be realized, (6) limiting the deductibility of certain executive compensation, (7) restricting the deductibility of entertainment and lobbying-related expenses, (8) requiring regulated entities to employ the average rate assumption method (“ARAM”) to refund excess deferred taxes created by the rate change to their customers, and (9) changing the rules regarding taxability of contributions made by government or civic groups.

The Company's gas and electric utilities currently recover corporate income tax expense in Commission approved rates charged to customers. The IURC and the PUCO both issued orders which initiated proceedings to investigate the impact of the TCJA on utility companies and customers within each state. In addition, both Commissions have ordered each utility to establish regulatory assets and liabilities to record all estimated impacts of tax reform starting January 1, 2018. The Company is complying with both orders. In Indiana, the IURC held an initial conference of parties on February 6, 2018, and an order was issued by the Commission on February 16, 2018, outlining the process the utility companies are to follow. In accordance with the order, the Company filed March 26, 2018 for proposed changes to its rates and charges to consider the impact of the lower corporate federal income tax rate. An order is expected in the second quarter of 2018 and rates will then be adjusted. In Ohio, in response to the PUCO's request for comments from utilities, Vectren submitted its response indicating that the issues should be addressed in its base rate case, which was filed on March 30, 2018.

8. Financing Activities

SIGECO Variable Rate Tax-Exempt Bonds
On March 1, 2018 and May 1, 2018, the Company, through SIGECO, executed first and second amendments to a Bond Purchase and Covenants Agreement originally signed in September 2017. These amendments provided SIGECO the ability to remarket bonds that were callable from current bondholders on those dates. Pursuant to these amendments, lenders purchased the following SIGECO bonds on March 1 and May 1, respectively:
- 2013 Series A Notes with a principal of $22.2 million and final maturity date of March 1, 2038; and
- 2013 Series B Notes with a principal of $39.6 million and final maturity date of May 1, 2043.

Prior to the call, the 2013 Series A Notes had an interest rate of 4.0% and the 2013 Series B Notes had an interest rate of 4.05%. The bonds converted to a variable rate based on the one month LIBOR through May 1, 2023.

The Company has now remarketed $152 million of tax exempt bonds through the Bonds Purchase and Covenants Agreement, which is the agreement's full capacity. Bonds remarketed through the Bond Purchase and Covenants Agreement in 2017 were:
- 2013 Series C Notes with a principal of $4.6 million and final maturity date of January 1, 2022;
- 2013 Series D Notes with a principal of $22.5 million and final maturity date of March 1, 2024;
- 2013 Series E Notes with a principal of $22.0 million and final maturity date of May 1, 2037; and
- 2014 Series B Notes with a principal of $41.3 million and final maturity date of July 1, 2025.

These bonds also have a variable interest rate based on the one month LIBOR through May 1, 2023.

The Company, through SIGECO, executed forward starting interest rate swaps during 2017 providing that on January 1, 2020, the Company will begin hedging the variability in interest rates on the 2013 Series A, B, and E Notes through final maturity dates. The swaps contain customary terms and conditions and generally provide offset for changes in the one month LIBOR rate. Other interest rate variability that may arise through the Bond Purchase and Covenants Agreement, such as variability caused by changes in tax law or SIGECO's credit rating, among others, may result in an actual interest rate above or below the anticipated fixed rate. Regulatory orders require SIGECO to include the impact of its interest rate risk management activities, such as gains and losses arising from these swaps, in its cost of capital utilized in rate cases and other periodic filings.

Long-Term Borrowing Facilities
The Merger would constitute a "Change of Control" under the note agreements pursuant to which Senior Notes issued by Utility Holdings in an aggregate principal amount of $1.025 billion were issued. While the Merger would not result in an event of default under such note agreements, upon the consummation of the Merger, Utility Holdings would be required to offer to repurchase these notes at 100% of the principal amount thereof plus accrued interest.

9. Commitments & Contingencies

Commitments
The Company's regulated utilities have both firm and non-firm commitments, some of which are between five and twenty year agreements to purchase natural gas, electricity, and coal, as well as certain transportation and storage rights. Costs arising from these commitments, while significant, are pass-through costs, generally collected

dollar-for-dollar from retail customers through regulator-approved cost recovery mechanisms.

Letters of Credit

The Company from time to time, through its subsidiaries, issues letters of credit that support consolidated operations. At March 31, 2018, letters of credit outstanding total $8.6 million.

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

10. Gas Rate & Regulatory Matters

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

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

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

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

Requests for Recovery under Indiana Regulatory Mechanisms
In August 2014, the IURC issued an Order approving the Company’s seven-year capital infrastructure replacement and improvement plan (the Plan), beginning in 2014, and the proposed accounting authority and recovery. Compliance projects and other infrastructure improvement projects were approved pursuant to Senate Bill 251 and 560, respectively. As provided in the two laws, the Order approved semi-annual filings for rate recovery of 100 percent of the costs, inclusive of return, related to these capital investments and operating expenses, with 80 percent of the costs, including a return, recovered currently via an approved tracking mechanism and 20 percent of the costs deferred and recovered in the Company’s next base rate proceeding. In addition, the Order established guidelines to annually update

the seven-year capital investment plan. Finally, the Order approved the Company’s proposal to recover eligible costs assigned to the residential customer class via a fixed monthly charge per residential customer.

On January 24, 2018, the IURC issued an order (January 2018 order) approving the inclusion in rates of investments made from January 2017 to June 2017. Through the January 2018 Order, approximately $482 million of the approved capital investment has been incurred and included for recovery. The January 2018 Order also approved the Company's plan update, which now totals $995 million through 2020.

On April 2, 2018, the Company submitted its eighth semi-annual filing, seeking approval of the recovery in rates of investments made through December 31, 2017.

In December 2016, PHMSA issued interim final rules related to integrity management for storage operations. Efforts are underway to implement the new requirements. Further, the Company reviewed the Underground Natural Gas Storage Safety Recommendations from a joint Department of Energy and PHMSA led task force. On August 3, 2017, the Company filed for authority to recover the associated costs using the mechanism allowed under Senate Bill 251. Approximately $15 million of operating expenses and $17 million of capital investments will be included in the plan over a four-year period beginning in 2018. The Company received the IURC Order approving the request for recovery on December 28, 2017. The Company does not have company-owned storage operations in Ohio.

At March 31, 2018 and December 31, 2017, the Company has regulatory assets related to the Plan totaling $78.8 million and $78.0 million, respectively.

Ohio Recovery and Deferral Mechanisms

The PUCO Order approving the Company's 2009 base rate case in the Ohio service territory authorized a distribution replacement rider (DRR). The DRR's primary purpose is recovery of investments in utility plant and related operating expenses associated with replacing bare steel and cast iron pipelines, as well as certain other infrastructure investments. This rider is updated annually for qualifying capital expenditures and allows for a return on those capital expenditures based on the rate of return approved in the 2009 base rate case. In addition, deferral of depreciation and the ability to accrue debt-related post-in-service carrying costs is also allowed until the related capital expenditures are included in the DRR. The Order also initially established a prospective bill impact evaluation on the annual deferrals. On February 19, 2014, the PUCO issued an Order approving a Stipulation entered into by the PUCO Staff and the Company which provided for the extension of the DRR for the recovery of costs incurred through 2017 and expanded the types of investment covered by the DRR to include recovery of certain other infrastructure investments. The Order limits the resulting DRR fixed charge per month for residential and small general service customers to specific graduated levels through 2017. The capital expenditure plan is subject to the graduated caps on the fixed DRR monthly charge applicable to residential and small general service customers approved in the Order. In the event the Company exceeds these caps, amounts in excess can be deferred for future recovery. The Order also approved the Company's commitment that the DRR can only be further extended as part of a base rate case. In the Company's base rate case, it requested extension to include investments made starting 2018 through completion of the program, currently estimated at 2023. In total, the Company has made capital investments on projects that are now in-service under the DRR totaling $326.5 million as of March 31, 2018, of which $261.1 million has been approved for recovery under the DRR through December 31, 2016. On May 1, 2018, the Company submitted its annual request for an adjustment in the DRR rates to recover investments made through December 31, 2017. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $32.9 million and $31.2 million at March 31, 2018 and December 31, 2017, respectively.

The PUCO has also issued Orders approving the Company's filings under Ohio House Bill 95. These Orders approve deferral of the Company’s Ohio capital expenditure program for items not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. Ohio House Bill 95 Orders also 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. The Company has requested recovery of these deferrals through December 31, 2017 in its rate case, along with a mechanism to recover future Ohio House Bill 95 deferrals. At March 31, 2018 and December 31, 2017, the Company has regulatory assets totaling $73.7 million and $66.1 million, respectively, associated with the deferral of depreciation, post-in-service carrying costs, and property taxes. On May 1, 2018, the Company submitted its most recent annual report required under its House Bill 95 Order. This report covers the Company's capital expenditure program through calendar year 2017.

Vectren Ohio Gas Rate Case
On March 30, 2018, the Company filed with the PUCO a request for a $34 million increase in its base rates and charges for VEDO’s distribution business in its 17 county service area in west-central Ohio. The requested increase includes the benefit of the TCJA, which decreased the corporate rate from 35 percent to 21 percent. The filing is necessary to extend the DRR mechanism beyond 2017 through completion of the accelerated replacement program, and to recover the costs of capital investments made over the past ten years, much of which has been deferred as part of the Company’s capital expenditure

program under Ohio House Bill 95. The filing also addresses the recovery of the current Ohio House Bill 95 regulatory asset balance, and a proposed mechanism to recover future Ohio House Bill 95 deferrals. The Company expects the PUCO staff to file its report, including recommendations, in the third quarter of 2018 and issue an order by early 2019.

Pipeline and Hazardous Materials Safety Administration (PHMSA)
In March 2016, PHMSA published a notice of proposed rulemaking (NOPR) on the safety of gas transmission and gathering lines. The proposed rule addresses many of the remaining requirements of the 2011 Pipeline Safety Act, with a particular focus on extending integrity management rules to address a much larger portion of the natural gas infrastructure and adds requirements to address broader threats to the integrity of a pipeline system. The Company continues to evaluate the impact these proposed rules will have on its integrity management programs and transmission and distribution systems. Progress on finalizing the rule continues to work through the administrative process. The rule is expected to be finalized in 2019 and the Company believes the costs to comply with the new rules would be considered federally mandated and therefore should be recoverable under Senate Bill 251 in Indiana and eligible for deferral under House Bill 95 in Ohio.

11. Electric Rate & Regulatory Matters

Electric Requests for Recovery under Senate Bill 560
The provisions of Senate Bill 560, as described in the Gas Rate & Regulatory Matters footnote for gas projects, are the same for qualifying electric projects. On February 23, 2017, the Company filed for authority to recover costs related to its electric system modernization plan, using the mechanism allowed under Senate Bill 560. The electric system modernization plan includes investments to upgrade portions of the Company’s network of substations, transmission and distribution systems, to enhance reliability and allow the grid to accept advanced technology to improve the information and service provided to customers.

On September 20, 2017, the IURC issued an Order approving the Company’s electric system modification as reflected in the settlement agreement reached between the Company, the OUCC and a coalition of industrial customers. The settlement agreement includes defined annual caps on recoverable capital investments. The settlement agreement also addresses how the eligible costs would be recoverable in rates, with a cap on the residential and small general service fixed monthly charge per customer in each semi-annual filing. The remaining costs to residential and small general service customers would be recovered via a volumetric energy charge. The settlement agreement removed advanced metering infrastructure (AMI or digital meters) from the plan. However, deferral of the costs for AMI was agreed upon in the settlement whereby the company can move forward with deployment in the near-term. The request for cost recovery for the AMI project will not occur until the next base rate review proceeding, which is expected to be filed by the end of 2023. In that proceeding, settling parties have agreed not to oppose inclusion of the AMI project in rate base.

On August 1, 2017, the Company filed with the IURC its initial request for approval of the revenue requirement associated with a capital investment of $7.1 million through April 30, 2017. On December 20, 2017, the IURC issued an Order approving the initial rates necessary to begin cash recovery of 80 percent of the revenue requirement, inclusive of return, with the remaining 20 percent deferred for recovery in the utility's next general rate case. On February 1, 2018, the Company submitted its second semi-annual filing, seeking approval of the recovery in rates of investments made of approximately $31 million through October 31, 2017. As of March 31, 2018 and December 31, 2017, the Company has regulatory assets related to the Electric TDSIC plan totaling $4.5 million and $4.3 million, respectively.

SIGECO Electric Environmental Compliance Filing

On January 28, 2015, the IURC issued an Order approving the Company’s request for approval of capital investments in its coal-fired generation units to comply with new EPA mandates related to mercury and air toxic standards (MATS) effective in 2015 and to address an outstanding Notice of Violation (NOV) from the EPA pertaining to its A.B. Brown generating station sulfur trioxide emissions. 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

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coal and proposed surrogate limits for non-mercury and acid gas hazardous air pollutants.

As of 2017, the Company has completed investments of $30 million on equipment to control mercury in both air and water emissions, and $40 million to address the issues raised in the NOV. The Order approved the Company’s request for deferred accounting treatment, as supported by provisions under Indiana Senate Bill 29 and Senate Bill 251. The accounting treatment includes the deferral of depreciation and property tax expense related to these investments, accrual of post-in-service carrying costs, and deferral of incremental operating expenses related to compliance with these standards. The initial phase of the projects went into service in 2014, with the remaining investment going into service in 2016. As of March 31, 2018, the Company has approximately $14.0 million deferred related to depreciation and operating expenses, and $5.1 million deferred related to post-in-service carrying costs. MATS compliance was required beginning April 16, 2015 and the Company continues to operate in full compliance with the MATS rule.

On February 20, 2018, the Company filed a request to commence recovery, under Senate Bill 251, of its already approved investments associated with the MATS and NOV Compliance Projects, including recovery of the authorized deferred balance. As proposed, recovery would reflect 80 percent of the authorized costs, including a return, recovery of depreciation and incremental operating expenses, and recovery of the prior deferred balance over a proposed period of 15 years. The remaining 20 percent will be deferred until the Company’s next base rate proceeding. The Company expects an order in the first half of 2019 since filed as a part of the electric generation transition plan case discussed below.

SIGECO Electric Demand Side Management (DSM) Program Filing
On March 28, 2014, Indiana Senate Bill 340 was signed into law. The legislation allows for industrial customers to opt out of participating in energy efficiency programs and as a result of this legislation, customers representing most of the eligible load have since opted out of participation in the applicable energy efficiency programs.

Indiana Senate Bill 412 (Senate Bill 412) requires electricity suppliers to submit energy efficiency plans to the IURC at least once every three years. Senate Bill 412 also requires the recovery of all program costs, including lost revenues and financial incentives associated with those plans and approved by the IURC. The Company made its first filing pursuant to this bill in June 2015, which proposed energy efficiency programs for calendar years 2016 and 2017. On March 23, 2016, the IURC issued an Order approving the Company’s 2016-2017 energy efficiency plan. The Order provided for cost recovery of program and administrative expenses and included performance incentives for reaching energy savings goals. The Order also included a lost margin recovery mechanism that would have limited recovery related to new programs to the shorter of four years or the life of the installed energy efficiency measure. Prior electric energy efficiency orders did not limit lost margin recovery in this manner. This ruling followed other IURC decisions implementing the same lost margin recovery limitation with respect to other electric utilities in Indiana. The Company appealed this lost margin recovery restriction based on the Company’s commitment to promote and drive participation in its energy efficiency programs.

On March 7, 2017, the Indiana Court of Appeals reversed the IURC finding on the Company's 2016-2017 energy efficiency plan that the four year cap on lost margin recovery was arbitrary and the IURC failed to properly interpret the governing statute requiring it to review the utility's originally submitted DSM proposal and either approve or reject it as a whole, including the proposed lost margin recovery. The case was remanded to the IURC for further proceedings. On June 13, 2017, the Company filed additional testimony supporting the plan. In response to the proposals to cap lost margin recovery, the Company filed supplemental testimony that supported lost margin recovery based on the average measure life of the plan, estimated at nine years, on 90 percent of the direct energy savings attributed to the programs. Testimony of intervening parties was filed on July 26, 2017, opposing the Company's proposed lost margin recovery. An evidentiary hearing was held in September 2017. On December 20, 2017, the

Commission issued an order approving the DSM Plan for 2016-2017 including the recovery of lost margins consistent with the Company's proposal. On January 22, 2018, certain intervening parties initiated an appeal to the Indiana Court of Appeals. The briefs of appealing parties are currently due on May 3, 2018. While no assurance as to the ultimate outcome can be provided, based upon the record of the proceedings, as well as the findings in the Commission's order, the Company expects to prevail in this appeal.

On April 10, 2017, the Company submitted its request for approval to the IURC of its Energy Efficiency Plan for calendar years 2018 through 2020. Consistent with prior filings, this filing included a request for continued cost recovery of program and administrative expenses, including performance incentives for reaching energy savings goals and continued recovery of lost margins consistent with the modified proposal in the 2016-2017 plan. Filed testimony of intervening parties was received on July 26, 2017, opposing the Company's proposed lost margin recovery. An evidentiary hearing was held in September 2017. On December 28, 2017, the Commission issued an order approving the 2018 through 2020 Plan, inclusive of recovery of lost margins consistent with the Order issued on December 20, 2017. On January 26, 2018, certain intervening parties initiated an appeal to the Indiana Court of Appeals. The briefs of appealing parties are currently due on May 3, 2018. While no assurance as to the ultimate outcome can be provided, based upon the record of the proceedings, as well as the findings in the Commission's order, the Company expects to prevail in this appeal.

For the three months ended March 31, 2018 and 2017, the Company recognized electric utility revenue of $3.1 million and $3.0 million, respectively, associated with lost margin recovery approved by the Commission.

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

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

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

The Company has reflected these results in its financial statements. As of March 31, 2018, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $132.6 million at March 31, 2018.

On April 14, 2017, the U.S. Court of Appeals for the District of Columbia circuit vacated the FERC Opinion in a prior case that established a new methodology for calculating ROE. This methodology was utilized in the final order in the Company's first complaint case, and the initial decision in the Company's second complaint case. The Appeals Court stated that FERC did not prove the existing ROE was not just and reasonable, failed to provide any reasoned basis for their selected ROE, and remanded to the FERC for further justification of its ROE calculation. The Company will continue to monitor this proceeding and evaluate any potential impacts on the Company's complaint cases but would not expect them to be material.

Electric Generation Transition Plan
As required by Indiana regulation, the Company filed its 2016 Integrated Resource Plan (IRP) with the IURC on December 16, 2016. The State requires each electric utility to perform and submit an IRP that uses economic

modeling to consider the costs and risks associated with available resource options to provide reliable electric service for the next twenty-year period. During 2016, the Company held three public stakeholder meetings to gather input and feedback as well as communicate results of the IRP process as it progressed. In developing its IRP, the Company considered both the cost to continue operating its existing generation units in a manner that complies with current and anticipated future environmental requirements, as well as various resource alternatives, such as the use of energy efficiency programs and renewable resources as part of its overall generation portfolio. After submission, parties to the IRP provided comments on the plan. While the IURC does not approve or reject the IRP, the process involves the issuance of a staff report that provides comments on the IRP. The final report was issued on November 2, 2017. The Company has taken the comments provided in the report into consideration in its generation transition plan.

The Company’s IRP considered a broad range of potential resources and variables and is focused on ensuring it offers a reliable, reasonably priced generation portfolio as well as a balanced energy mix. Consistent with the recommendations presented in the Company’s IRP and as a direct result of significant environmental investments required to comply with current regulations, the Company plans to retire a significant portion of its generating fleet by the end of 2023. On February 20, 2018, the Company filed a petition seeking authorization from the IURC to construct a new 800-900 MW natural gas combined cycle generating facility to replace this capacity at an approximate cost of $900 million, which includes the cost of a new natural gas pipeline to serve the plant. The Company is requesting a certificate of public convenience
and necessity (CPCN) authorizing construction timelines and costs of new generation resources, as well as necessary unit retrofits, to implement the generation transition plan. In that filing, the Company seeks approval of its generation transition plan, including the authority to defer the cost of new generation, including the ability to accrue AFUDC and defer depreciation until the facility is placed in base rates.

As a part of this same proceeding, the Company seeks recovery under Senate Bill 251 of costs to be incurred for environmental investments to be made at its F.B. Culley generating plant to comply with Effluent Limitation Guidelines and Coal Combustion Residuals rules. The F.B. Culley investments, estimated to be approximately $90 million, will begin in 2019 and will allow the F.B. Culley Unit 3 generating facility to comply with environmental requirements and continue to provide generating capacity to the Company’s electric customers. Under Senate Bill 251, the Company is seeking recovery of 80 percent of the approved costs, including a return, using a tracking mechanism, with the remaining 20 percent of the costs deferred for recovery in the Company’s next base rate proceeding.

Intervenors must file testimony by August 10, 2018. Evidentiary hearings are scheduled to commence October 9, 2018. The Company expects an order from the Commission in this proceeding in the first half of 2019.

On August 30, 2017, the IURC issued an Order approving the Company’s request to recover costs related to the construction of three solar projects, using the mechanism allowed under Senate Bill 29, which allows for timely recovery of costs and expenses incurred during the construction and operation of clean energy projects. These investments, presented as part of the Company’s (IRP) submitted in December 2016, allow the Company to add approximately 4 MW of universal solar generation, rooftop solar generation, and 1 MW of battery storage resources to its portfolio. The approved cost of the projects cannot exceed the approximate $16 million estimate submitted by the Company, without seeking further Commission approval.

On February 20, 2018, the Company announced it is finalizing details to install an additional 50 MW of universal solar energy, consistent with its IRP. On May 4, 2018, the Company filed a petition with the IURC requesting a CPCN authorizing construction and authority to recover costs associated with the project pursuant to Senate Bill 29. No procedural schedule has been set, but the Company would expect an order in the first half of 2019.

In addition, the Company intends to continue to offer energy efficiency programs annually. Similarly, as discussed in more detail below, the extension of preliminary compliance deadlines related to ELG implementation are not expected to have a significant impact on the Company’s long term generation transition plan.

On September 21, 2017, the Company and Alcoa agreed to continue the joint ownership and operation of Warrick Unit 4 through 2023. This aligns with the Company's long-term electric generation transition plan, and the expected exit at the end of 2023 is consistent with the IRP which reflects having completed all planned unit retirements and bringing new resources online by that date.

12. Environmental & Sustainability Matters

The Company initiated a corporate sustainability program in 2012 with the publication of the initial corporate sustainability report. Since that time, the Company continues to develop strategies that focus on environmental, social, and governance (ESG) factors that contribute to the long-term growth of a sustainable business model. The sustainability policies and efforts, and in particular its policies and procedures designed to ensure compliance with applicable laws and regulations, are directly overseen by the Company's Corporate Responsibility and Sustainability Committee, as well as vetted with the Company's Board of Directors. Further discussion of key goals, strategies, and governance practices can be found in the Company’s current sustainability report, at www.vectren.com/sustainability, which received core level certification from the Global Reporting Initiative.

In furtherance of the Company’s commitment to a sustainable business model, and as detailed further below, the Company is transitioning its electric generation portfolio from nearly total reliance on baseload coal to a fully diversified and balanced portfolio of fuels that will provide long-term electric supply needs in a safe and reliable manner while dramatically lowering emissions of carbon and the carbon intensity of its electric generating fleet. If authorized by the Commission, by 2024 the Company plans to construct a new natural gas combined cycle generating facility to replace four coal-fired units totaling over 700 MWs which, when combined with its planned 54 MWs of new renewable generation, will achieve a 60 percent reduction in carbon emissions from 2005 levels and reduce carbon intensity to 980 lbs CO_2 / MMBTU and position the Company to comply with future carbon emission reduction requirements. In addition to diversification of its fuel portfolio, the Company is also seeking authorization to significantly upgrade wastewater treatment for its remaining coal-fired unit and exploring opportunities to continue to recycle ash from its coal ash ponds. This generation diversification strategy aligns with the Company’s ongoing investments in new electric infrastructure through the approved $450 million grid modernization program, and is set forth in more detail in the Company’s upcoming 2017 corporate sustainability report.

Further, as part of its commitment to a culture of compliance excellence and continuous improvement, the Company continues to enhance its Safety Management System (SMS) which was implemented several years ago. The risk analysis and process review provides valuable input into the assessment process used to drive the ongoing infrastructure improvement plans being executed by the Company’s gas and electric utilities.

The Company is subject to extensive environmental regulation pursuant to a variety of federal, state, and municipal laws and regulations. These environmental regulations impose, among other things, restrictions, liabilities, and obligations in connection with the storage, transportation, treatment, and disposal of hazardous substances and limit airborne emissions from electric generating facilities including particulate matter, sulfur dioxide (SO_2), nitrogen oxide (NO_x), and mercury, among others. Environmental legislation and regulation also requires that facilities, sites, and other properties associated with the Company's operations be operated, maintained, abandoned, and reclaimed to the satisfaction of applicable regulatory authorities. The Company's current costs to comply with these laws and regulations are significant to its results of operations and financial condition. Similar to the costs associated with federal mandates in the Pipeline Safety Law, Senate Bill 251 is also applicable to federal environmental mandates impacting SIGECO's electric operations.

Coal Ash Waste Disposal, Ash Ponds and Water

Coal Combustion Residuals Rule
In April 2015, the EPA finalized its Coal Combustion Residuals (CCR) rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The final rule allows beneficial reuse of ash and the majority of the ash generated by the Company’s generating plants will continue to be reused. As it relates to the CCR Rule, the Water Infrastructure Improvements for the Nation (WIIN) Act was passed in December 2016 by Congress that would provide for enforcement of the federal program by states under approved state programs rather than citizen suits. Additionally, aspects of the CCR rule are currently being challenged by multiple parties in judicial review proceedings. In August 2017, the EPA issued guidance to states to clarify their ability to implement the Federal CCR rule through state permit programs as allowed in the WIIN Act legislation. Alternative compliance

mechanisms for groundwater, corrective action and other areas of the rule could be granted under the regulatory oversight of a state enforced program. On September 14, 2017, the EPA announced its intent to reconsider portions of the Federal CCR rule in line with the guidance issued to states. On March 15, 2018, EPA published its proposed reconsideration of certain provisions of the existing CCR rule to bring the rule consistent with the WIIN Act. The Company does not anticipate the reconsideration to change its current plans for pond closure as announced in its generation transition plan. While the state program development and EPA reconsideration move forward, the existing CCR compliance obligations remain in effect.

Under the existing CCR rule, the Company is required to complete a series of integrity assessments, including seismic modeling given the Company’s facilities are located within two seismic zones, and groundwater monitoring studies to determine the remaining service life of the ponds and whether a pond must be retrofitted with liners or closed in place, with bottom ash handling conversions completed. In late 2015, using general utility industry data, the Company prepared cost estimates for the retirement of the ash ponds at the end of their useful lives, based on its interpretation of the closure alternatives contemplated in the final rule. The resulting estimates ranged from approximately $35 million to $80 million. These estimates contemplated final capping and monitoring costs of the ponds at both F.B. Culley and A.B. Brown generating stations. These rules are not applicable to the Company's Warrick generating unit, as this unit has historically been part of a larger generating station that predominantly serves an adjacent industrial facility. In March 2018, the Company posted to its public website a first report of preliminary groundwater monitoring data in accordance with the requirements of the CCR rule. This data preliminarily suggests potential groundwater impacts very close to the Company's ash impoundments, and further analysis is ongoing; however, at this time the Company does not believe that there are any impacts to public or private drinking water sources.

Since 2015, the Company continues to refine site specific estimates and now estimates the costs to be in the range of $45 million to $135 million. Significant factors impacting the resulting cost estimates include the closure time frame and the method of closure. Current estimates contemplate complete removal under the assumption of beneficial reuse of the ash at A.B. Brown, as well as implications of the Company’s generation transition plan. Ongoing analysis, the continued refinement of assumptions, or the inability to beneficially reuse the ash, either from a technological or economical perspective, could result in estimated costs in excess of the current range.

As of March 31, 2018, the Company has recorded an approximate $40 million asset retirement obligation (ARO). The recorded ARO reflects the present value of the approximate $45 million in estimated costs in the range above. These assumptions and estimations are subject to change in the future and could materially impact the amount of the estimated ARO.

In order to maintain current operations of the ponds, the Company spent approximately $17 million on the reinforcement of the ash pond dams and other operational changes in 2016 to meet the more stringent 2,500 year seismic event structural and safety standard in the CCR rule.

Effluent Limitation Guidelines (ELG)

Under the Clean Water Act, the EPA sets technology-based guidelines for water discharges from new and existing electric generation facilities. In September 2015, the EPA finalized revisions to the existing steam electric ELG setting stringent technology-based water discharge limits for the electric power industry. The EPA focused this rulemaking on wastewater generated primarily by pollution control equipment necessitated by the comprehensive air regulations, specifically setting strict water discharge limits for arsenic, mercury and selenium for scrubber waste waters. The ELG will be implemented when existing water discharge permits for the plants are renewed, with compliance activities expected to commence where operations continue, within the 2018-2023 time frame. The ELG work in tandem with the aforementioned CCR requirements, effectively prohibiting the use of less costly lined sediment basin options for disposal of coal combustion residuals, and virtually mandate conversions to dry bottom ash handling.

At the time of ELG finalization, the wastewater discharge permit for the A.B. Brown power plant had an expiration date of October 2016 and, for the F.B. Culley plant, a date of December 2016, and final renewals were issued by the Indiana Department of Environmental Management (IDEM) in February 2017 and March 2017, respectively. As part of the permit renewals, the Company requested alternate compliance dates for ELG, which were approved by IDEM. For plants identified in the Company’s IRP to be retired prior to December 31, 2023, the Company has requested those plants would not require new treatment technology, which was approved by IDEM provided the Company notifies

IDEM within one year of issuance of the renewal of its intent to retire the unit. For the F.B. Culley 3 plant, the Company requested a 2020 compliance date for dry bottom ash and 2023 compliance date for flue gas desulfurization wastewater, which was approved by IDEM and finalized in the permit renewal. Discussion of these environmental investments at the F.B. Culley 3 plant is included in the generation transition plan in Note 11.

On April 13, 2017, as part of the Administration's regulatory reform initiative, which is focused on the number and nature of regulations, the EPA granted petitions to reconsider the ELG rule, and indicated it would stay the current implementation deadlines in the rule during the pendency of the reconsideration. The EPA has also sought a stay of the current judicial review litigation in federal district court. The court has yet to grant the indefinite stay sought by EPA, and instead placed the parties on a periodic status update schedule. On September 13, 2017, EPA finalized a rule postponing certain interim compliance dates by two years, but did not postpone the final compliance deadline of December 31, 2023. As the Company does not currently have short-term ELG implementation deadlines in its recently renewed wastewater discharge permits, the Company does not anticipate immediate impacts from the EPA's two-year extension of preliminary implementation deadlines due to the longer compliance time frames granted by IDEM, and will continue to work with IDEM to evaluate further implementation plans. Moreover, the Company believes the two year extension of the ELG preliminary implementation deadlines and reconsideration process does not impact its generation transition plan as modeled in the IRP because the final compliance deadline of December 31, 2023 is still in place and enhanced wastewater treatment for scrubber discharge water will still be required by a reconsidered ELG rule even if the EPA revises stringency levels.

Cooling Water Intake Structures
Section 316(b) of the Clean Water Act requires generating facilities use the "best technology available" (BTA) to minimize adverse environmental impacts on a body of water. More specifically, Section 316(b) is concerned with impingement and entrainment of aquatic species in once-through cooling water intake structures used at electric generating facilities. A final rule was issued by the EPA on May 19, 2014. The final rule does not mandate cooling water tower retrofits but requires that IDEM conduct 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 the Company's facilities. The Company is currently undertaking the required ecological studies and anticipates timely compliance in 2021-2022. To comply, the Company believes capital investments will likely be in the range of $4 million to $8 million.

Air Quality

Ozone NAAQS
On November 26, 2014, the EPA proposed to tighten the current National Ambient Air Quality Standard (NAAQS) for ozone from the current standard of 75 parts per billion (ppb) to a level within the range of 65 to 70 ppb. On October 1, 2015, the EPA finalized a new NAAQS for ozone at the high end of the range, or 70 ppb. On September 16, 2016, Indiana submitted its initial determination to the EPA recommending counties in southwest Indiana, specifically Vanderburgh, Posey and Warrick, be declared in attainment of the new more stringent ozone standard based upon air monitoring data from 2014-2016. In November 2017, EPA finalized its designations of Vanderburgh, Posey, and Warrick counties as being in attainment with the current 70 ppb standard.

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

Climate Change and Carbon Strategy

On August 3, 2015, the EPA released its final Clean Power Plan rule (CPP) which required a 32 percent reduction in carbon emissions from 2005 levels. This would result in a final emission rate goal for Indiana of 1,242 lb CO_2/MWh to be achieved by 2030 and implemented through a state implementation plan. The final rule was published in the Federal Register on October 23, 2015, and that action was immediately followed by litigation initiated by Indiana and 23 other states as a coalition challenging the rule. In January 2016, the reviewing court denied the states' and other parties requests to stay the implementation of the CPP pending completion of judicial review. On January 26, 2016, 29 states and state agencies, including the 24 state coalition referenced above, filed a request for immediate stay of implementation of the rule with the U.S. Supreme Court. On February 9, 2016, the U.S. Supreme Court granted the stay request to delay the implementation of the regulation while being challenged in court. Oral argument was held in September 2016. The stay will remain in place while the lower court concludes its review. In

March 2017, as part of the ongoing regulatory reform efforts of the Administration, the EPA filed a motion with the U.S. Court of Appeals for the District of Columbia circuit to suspend litigation pending the EPA’s reconsideration of the CPP rule, which was granted on April 28, 2017. Moreover, as indicated above, in October 2017, EPA published its proposal to repeal the CPP. Comments to the repeal proposal were due in April 2018. EPA's repeal proposal was quickly followed by an advanced notice of proposed rulemaking intended to solicit public comments on issues related to formulating a CPP replacement rule, which were similarly due in April 2018. Repeal without replacement of the CPP could create potential litigation risk arising from the absence of direct federal regulation in this area that courts have previously determined preempt common law nuisance claims.

Impact of Legislative Actions & Other Initiatives
At this time, compliance costs and other effects associated with reductions in GHG emissions or obtaining renewable energy sources remain uncertain. However, Vectren's generation transition plan, as set forth in its electric generation and compliance filing, will achieve 60 percent reductions in 2005 GHG emission levels by 2025, positioning the Company to comply with future regulatory or legislative actions with respect to mandatory GHG reductions.

In addition to the federal programs, the United States and 194 other countries agreed by consensus to limit GHG emissions beginning after 2020 in the 2015 United Nations Framework Convention on Climate Change Paris Agreement. The United States has proposed a 26-28 percent GHG emission reduction from 2005 levels by 2025. The Administration has indicated it intends to withdraw the United States' participation; however the Agreement provides that parties cannot petition to withdraw until November 2019. Since 2005 through 2017, the Company has achieved reduced emissions of CO_2 by an average of 35 percent (on a tonnage basis), and will increase that total to 60 percent at the conclusion of its generation transition plan, well above the 32 percent reduction that would be required under the CPP. While the litigation and the EPA's reconsideration of the CPP rules remains uncertain, the Company will continue to monitor regulatory activity regarding GHG emission standards that may affect its electric generating units.

Manufactured Gas Plants

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

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

The Company has accrued the estimated costs for further investigation, remediation, groundwater monitoring, and related costs for the sites. While the total costs that may be incurred in connection with addressing these sites cannot be determined at this time, the Company has recorded cumulative costs that it has incurred or reasonably expects to incur totaling approximately $44.2 million ($23.9 million at Indiana Gas and $20.3 million at SIGECO). The estimated accrued costs are limited to the Company’s share of the remediation efforts and are therefore net of exposures of other potentially responsible parties (PRP).

With respect to insurance coverage, Indiana Gas has received approximately $20.8 million from all known insurance carriers under insurance policies in effect when these plants were in operation. Likewise, SIGECO has settlement agreements with all known insurance carriers and has received approximately $15.7 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 both March 31, 2018 and December 31, 2017, approximately $2.5 million of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

13. Fair Value Measurements

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

(In millions)	March 31, 2018		December 31, 2017	
	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	$1,579.3	$1,664.8	$1,579.5	$1,715.5
Short-term borrowings	180.4	180.4	179.5	179.5
Cash & cash equivalents	14.5	14.5	9.8	9.8
Natural gas purchase instrument assets (1)	0.3	3.0	0.5	0.5
Natural gas purchase instrument liabilities (2)	5.1	5.1	4.5	4.5
Interest rate swap assets (3)	0.5	0.5	—	—
Interest rate swap liabilities (4)	—	—	1.4	1.4

(1) Presented in "Prepayments & other current assets" for current and "Other utility & corporate investments" for noncurrent on the Condensed Consolidated Balance Sheets (unaudited).
(2) Presented in "Accrued liabilities" for current and "Deferred credits & other liabilities" for noncurrent on the Condensed Consolidated Balance Sheets (unaudited).
(3) Presented in "Other utility & corporate investments" on the Condensed Consolidated Balance Sheets (unaudited).
(4) Presented in "Deferred credits & other liabilities" on the Condensed Consolidated Balance Sheets (unaudited).

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

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

The Company’s Indiana gas utilities entered into multiple five-year forward purchase arrangements to fix the price of natural gas for a portion of the Company’s gas supply. These arrangements, approved by the IURC, replaced normal purchase or normal sale long-term physical fixed-price purchases. The Company values these contracts using a pricing model that incorporates market-based information, and are classified within Level 2 of the fair value hierarchy. Gains and losses on these derivative contracts are deferred as regulatory liabilities or assets and are refunded to or collected from customers through the Company’s respective gas cost recovery mechanisms.

The Company, through SIGECO, executed forward starting interest rate swaps during 2017 providing that on January 1, 2020, the Company will begin hedging the variability in interest rates on the 2013 Series A, B, and E Notes, through final maturity dates. The Company values these contracts using a pricing model that incorporates market-based information, and are classified within Level 2 of the fair value hierarchy. Regulatory orders require SIGECO to include the impact of its interest rate risk management activities, such as gains and losses arising from these swaps, in its cost of capital utilized in rate cases and other periodic filings.

14. Impact of Recently Issued Accounting Standards

Leases

In February 2016, the FASB issued new accounting guidance for the recognition, measurement, presentation and disclosure of leasing arrangements. This ASU requires the recognition of lease assets and liabilities for those leases currently classified as operating leases while also refining the definition of a lease. In addition, lessees will be required to disclose key information about the amount, timing, and uncertainty of cash flows arising from leasing arrangements. This ASU is effective for the interim and annual reporting periods beginning January 1, 2019 and is required to be applied using a modified retrospective approach. In January 2018, the FASB issued amendments to the new lease standard, ASU No. 2018-01, allowing an entity to elect not to assess whether certain land easements are, or contain, leases when transitioning to the new lease standard. The Company is currently evaluating the standard to determine the impact it will have on the financial statements and will adopt the guidance effective January 1, 2019.

Other Recently Issued Standards

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

15. 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 Operations. Net income is the measure of profitability used by management for all operations.

Information related to the Company’s business segments is summarized below:

	Three Months Ended March 31,	
(In millions)	2018	2017
Revenues		
Gas Utility Services	$329.3	$292.8
Electric Utility Services	134.0	132.1
Other Operations	11.8	11.4
Eliminations	(11.7)	(11.3)
Total Revenues	$463.4	$425.0
Profitability Measure - Net Income		
Gas Utility Services	$56.0	$47.9
Electric Utility Services	14.0	13.7
Other Operations	4.3	4.3
Total Net Income	$74.3	$65.9

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

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 or the Company's parent) three operating public utilities: Indiana Gas Company, Inc. (Indiana Gas or Vectren Energy Delivery of Indiana - North), Southern Indiana Gas and Electric Company (SIGECO or Vectren Energy Delivery of Indiana - South), and Vectren Energy Delivery of Ohio, Inc. (VEDO). Herein, 'the Company' may also refer to Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Inc. and/or Vectren Energy Delivery of Ohio, Inc. The Company 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 the Company are holding companies as defined by the Energy Policy Act of 2005 (Energy Act).

Indiana Gas provides energy delivery services to approximately 603,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 146,000 electric customers and approximately 112,000 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 323,000 natural gas customers located near Dayton in west-central Ohio. The Company segregates its regulatory utility operations between a Gas Utility Services operating segment and an Electric Utility Services operating segment.

The following discussion and analysis should be read in conjunction with the unaudited condensed consolidated financial statements and notes thereto as well as the Company’s 2017 annual report filed on Form 10-K.

Merger with CenterPoint Energy, Inc.
On April 21, 2018, Vectren entered into an Agreement and Plan of Merger (the “Merger Agreement”), with CenterPoint Energy, Inc., a Texas corporation (“CenterPoint”), and Pacer Merger Sub, Inc., an Indiana corporation and wholly owned subsidiary of CenterPoint (“Merger Sub”). Pursuant to the Merger Agreement, and subject to the terms and conditions of the agreement, Merger Sub will merge with and into Vectren (the “Merger”), with Vectren continuing as the surviving corporation and becoming a wholly owned subsidiary of CenterPoint.

Subject to the terms and conditions in the Merger Agreement, upon closing, each share of common stock of Vectren shall be converted into the right to receive $72.00 in cash without interest.
Vectren, CenterPoint and Merger Sub each have made various representations, warranties and covenants in the Merger Agreement. Among other things, Vectren has agreed, subject to certain exceptions, to conduct its businesses in the ordinary course, consistent with past practice, from the date of the Merger Agreement until closing, and not to take certain actions prior to the closing of the Merger without the approval of CenterPoint. Vectren has made certain additional customary covenants, including, subject to certain exceptions: (1) to cause a meeting of the Company’s parent shareholders to be held to consider approval of the Merger Agreement, (2) not to solicit proposals relating to alternative business combination transactions and not to participate in discussions concerning, or furnish information in connection with, alternative business combination transactions and (3) not to withdraw its recommendation to the Company’s parent shareholders regarding the Merger. In addition, subject to the terms of the Merger Agreement, Vectren, CenterPoint and Merger Sub are required to use reasonable best efforts to obtain all required regulatory

approvals, which will include clearance under federal antitrust laws and certain approvals by federal regulatory bodies, including FERC, subject to certain exceptions, including that such efforts not result in a "Burdensome Condition" (as defined in the Merger Agreement). While approval of the Merger Agreement is not required by the Indiana Utility Regulatory Commission ("IURC") or the Public Utilities Commission of Ohio ("PUCO"), informational filings will be made with each commission.

Consummation of the Merger is subject to various conditions, including: (1) approval of the shareholders of Vectren, (2) expiration or termination of the applicable Hart-Scott-Rodino Act waiting period, (3) receipt of all required regulatory and statutory approvals without the imposition of a "Burdensome Condition," (4) absence of any law or order prohibiting the consummation of the Merger and (5) other customary closing conditions, including (a) subject to materiality qualifiers, the accuracy of each party's representations and warranties, (b) each party's compliance in all material respects with its obligations and covenants under the Merger Agreement and (c) the absence of a material adverse effect with respect to Vectren and its subsidiaries.

The Merger Agreement contains certain termination rights for both Vectren and CenterPoint, including if the Merger is not consummated by April 21, 2019 (subject to extension for an additional six months if all of the conditions to closing, other than the conditions related to obtaining regulatory approvals, have been satisfied). The Merger Agreement also provides for certain termination rights for each of Vectren and CenterPoint, and provides that, upon termination of the Merger Agreement under certain specified circumstances, CenterPoint would be required to pay a termination fee of $210 million to Vectren, and under other specified circumstances Vectren would be required to pay CenterPoint a termination fee of $150 million.

Executive Summary of Consolidated Results of Operations

In the first quarter of 2018, the Company's earnings were $74.3 million, compared to $65.9 million in 2017. The Company's results in the quarter reflect increased earnings from the returns on continued investment in the gas infrastructure replacement programs in Indiana and Ohio and the favorable impact of weather in 2018 as compared to the warmer than normal weather in 2017.

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 other 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. Following is a discussion and analysis of margin generated from regulated utility operations.

Gas Utility Margin (Gas utility revenues less Cost of gas sold)
Gas Utility margin and throughput by customer type follows:

	Three Months Ended March 31,	
(In millions)	2018	2017
Gas utility revenues	$329.3	$292.8
Cost of gas sold	145.2	112.9
Total gas utility margin	$184.1	$179.9
Margin attributed to:		
Residential & commercial customers	$137.5	$139.4
Industrial customers	22.1	21.1
Other	3.1	2.7
Regulatory expense recovery mechanisms	21.4	16.7
Total gas utility margin	$184.1	$179.9
Sold & transported volumes in MMDth attributed to:		
Residential & commercial customers	55.2	42.9
Industrial customers	42.3	34.9
Total sold & transported volumes	97.5	77.8

Gas utility margins were $184.1 million for the three months ended March 31, 2018, and compared to 2017, increased $4.2 million in the quarter. Gas utility margins increased $12.8 million in the quarter when excluding margin from regulatory expense recovery mechanisms, which increased $4.7 million, and the impact of tax reform on margins, which in the first quarter of 2018 were reduced by $13.3 million to accrue for customer refunds resulting from the decrease in the corporate tax rate from 35 percent to 21 percent. Gas margin was favorably impacted by increased returns on infrastructure replacement programs in Indiana and Ohio of $8.9 million. Large customer margins were up $1.7 million in the quarter, largely driven by favorable weather compared to the first quarter of 2017. With rate designs that substantially limit the impact of weather on small customer margin, the normal weather in the first quarter of 2018 compared to the warmer than normal weather in the first quarter of 2017 increased sold and transported volumes, but had only a slight favorable impact on small customer margin. Heating degree days were 102 percent of normal in Ohio and 99 percent of normal in Indiana in the first quarter of 2018, compared to 92 percent of normal in Ohio and 85 percent of normal in Indiana in the same period in 2017.

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

	Three Months Ended March 31,	
(In millions)	2018	2017
Electric utility revenues	$134.0	$132.1
Cost of fuel & purchased power	42.2	41.2
Total electric utility margin	$91.8	$90.9
Margin attributed to:		
Residential & commercial customers	$57.7	$57.6
Industrial customers	21.7	23.0
Other	1.0	0.9
Regulatory expense recovery mechanisms	4.6	2.4
Subtotal: retail	$85.0	$83.9
Wholesale power & transmission system margin	6.8	7.0
Total electric utility margin	$91.8	$90.9
Electric volumes sold in GWh attributed to:		
Residential & commercial customers	658.5	601.1
Industrial customers	495.4	491.4
Other customers	7.7	6.0
Total retail volumes	1,161.6	1,098.5
Wholesale	130.9	78.8
Total volumes sold	1,292.5	1,177.3

Retail
Electric retail utility margins were $85.0 million for the three months ended March 31, 2018, and compared to 2017, increased by $1.1 million. Electric retail utility margins increased $4.8 million in the quarter when excluding margin from regulatory expense recovery mechanisms, which increased $2.2 million, and the impact of tax reform on margins, which in the first quarter of 2018 were reduced by $5.9 million to accrue for customer refunds resulting from the decrease in the corporate tax rate. Electric margin, which is not protected by weather normalizing mechanisms, reflects a $4.2 million increase in customer margin in the quarter as annualized heating degree days were 99 percent of normal in 2018 compared to 85 percent of normal in 2017.

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

	Three Months Ended March 31,	
(In millions)	2018	2017

MISO Transmission system margin	$5.4	$5.8
MISO Off-system margin	1.4	1.2
Total wholesale margin	$6.8	$7.0

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms and other transmission system operations, totaled $5.4 million and $5.8 million during the three months ended March 31, 2018 and 2017, respectively. The impact of tax reform reduced MISO Transmission system margins by $0.5 million in the three months ended March 31, 2018. The Company has invested $157.7 million in qualifying projects. The net plant balance for these projects totaled $132.6 million at March 31, 2018. These projects include an interstate 345 kV transmission line that connects the

Company’s A.B. Brown Generating Station to a generating station in Indiana owned by Duke Energy to the north and to a generating station in Kentucky owned by Big Rivers Electric Corporation to the south; a substation; and another transmission line. These projects earn a FERC approved equity rate of return on the net plant balance and recover operating expenses. In September 2016, the FERC issued a final order authorizing the transmission owners to receive a 10.32 percent base ROE plus, a separately approved 50 basis point adder compared to the previously authorized 12.38 percent. The Company has reflected these outcomes in its financial statements. The 345 kV project is the largest of these qualifying projects, with an original cost of $106.8 million that earned the FERC approved equity rate of return, including while under construction.

In the first quarter of 2018, margin from off system sales was $1.4 million compared to $1.2 million in 2017. The base rate changes implemented in May 2011 require wholesale margin from off-system sales earned above or below $7.5 million per year to be shared equally with customers. Results for the periods presented are net of sharing are consistent with the prior period.

Operating Expenses

Other Operating
During the first quarter of 2018, other operating expenses were $94.8 million, an increase of $9.2 million, compared to the first quarter of 2017. Excluding costs recovered directly in margin, other operating expenses increased $3.9 million when compared to 2017, due to an increase in weather related energy delivery operations and maintenance expenses.

Depreciation & Amortization
In the first quarter of 2018, depreciation and amortization expense was $61.0 million, compared to $57.4 million in 2017. The increases reflect increased plant placed in service, which is largely driven by increased gas utility plant as a result of the Indiana and Ohio infrastructure programs.

Taxes Other Than Income Taxes
Taxes other than income taxes were $19.2 million and $14.4 million for the first quarter of 2018 and 2017, respectively. The increase in taxes other than income taxes in the quarter compared to 2017 was primarily related to higher property taxes, which is largely driven by increased gas utility plant as a result of the Indiana and Ohio infrastructure programs.

Income Taxes
Income taxes were $15.6 million and $37.0 million for the first quarter of 2018 and 2017, respectively. The decrease relates primarily to the decline in the federal income tax rate from 35% to 21% effective January 1, 2018, as well as the amortization of excess deferred income taxes beginning in the first quarter of 2018. Both the tax rate change and the excess deferred tax amortization relate directly to the passage of the TCJA in December 2017 and have associated revenue reductions.

Other Income - Net
Other income-net reflects income of $8.8 million for the first quarter of 2018, an increase of $1.8 million, compared to 2017. The increases are primarily due to increased AFUDC driven by increased capital expenditures related to gas infrastructure investment programs.

Gas Rate & Regulatory Matters

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

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

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

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

Requests for Recovery under Indiana Regulatory Mechanisms

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

On January 24, 2018, the IURC issued an order (January 2018 order) approving the inclusion in rates of investments made from January 2017 to June 2017. Through the January 2018 Order, approximately $482 million of the approved capital investment has been incurred and included for recovery. The January 2018 Order also approved the Company's plan update, which now totals $995 million through 2020.

On April 2, 2018, the Company submitted its eighth semi-annual filing, seeking approval of the recovery in rates of investments made through December 31, 2017.

In December 2016, PHMSA issued interim final rules related to integrity management for storage operations. Efforts are underway to implement the new requirements. Further, the Company reviewed the Underground Natural Gas Storage Safety Recommendations from a joint Department of Energy and PHMSA led task force. On August 3, 2017, the Company filed for authority to recover the associated costs using the mechanism allowed under Senate Bill 251. Approximately $15 million of operating expenses and $17 million of capital investments will be included in the plan over a four-year period beginning in 2018. The Company received the IURC Order approving the request for recovery on December 28, 2017. The Company does not have company-owned storage operations in Ohio.

At March 31, 2018 and December 31, 2017, the Company has regulatory assets related to the Plan totaling $78.8 million and $78.0 million, respectively.

Ohio Recovery and Deferral Mechanisms

The PUCO Order approving the Company's 2009 base rate case in the Ohio service territory authorized a distribution replacement rider (DRR). The DRR's primary purpose is recovery of investments in utility plant and related operating expenses associated with replacing bare steel and cast iron pipelines, as well as certain other infrastructure investments. This rider is updated annually for qualifying capital expenditures and allows for a return on those capital expenditures based on the rate of return approved in the 2009 base rate case. In addition, deferral of depreciation and the ability to accrue debt-related post-in-service carrying costs is also allowed until the related capital expenditures are included in the DRR. The Order also initially established a prospective bill impact evaluation on the annual deferrals. On February 19, 2014, the PUCO issued an Order approving a Stipulation entered into by the PUCO Staff and the Company which provided for the extension of the DRR for the recovery of costs incurred through 2017 and expanded the types of investment covered by the DRR to include recovery of certain other infrastructure investments. The Order limits the resulting DRR fixed charge per month for residential and small general service customers to specific graduated levels through 2017. The capital expenditure plan is subject to the graduated caps on the fixed DRR monthly charge applicable to residential and small general service customers approved in the Order. In the event the Company exceeds these caps, amounts in excess can be deferred for future recovery. The Order also approved the Company's commitment that the DRR can only be further extended as part of a base rate case. In the Company's base rate case, it requested extension to include investments made starting 2018 through completion of the program, currently estimated at 2023. In total, the Company has made capital investments on projects that are now in-service under the DRR totaling $326.5 million as of March 31, 2018, of which $261.1 million has been approved for recovery under the DRR through December 31, 2016. On May 1, 2018, the Company submitted its annual request for an adjustment in the DRR rates to recover investments made through December 31, 2017. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $32.9 million and $31.2 million at March 31, 2018 and December 31, 2017, respectively.

The PUCO has also issued Orders approving the Company's filings under Ohio House Bill 95. These Orders approve deferral of the Company’s Ohio capital expenditure program for items not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. Ohio House Bill 95 Orders also 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. The Company has requested recovery of these deferrals through December 31, 2017 in its rate case, along with a mechanism to recover future Ohio House Bill 95 deferrals. At March 31, 2018 and December 31, 2017, the Company has regulatory assets totaling $73.7 million and $66.1 million, respectively, associated with the deferral of depreciation, post-in-service carrying costs, and property taxes. On May 1, 2018, the Company submitted its most recent annual report required under its House Bill 95 Order. This report covers the Company's capital expenditure program through calendar year 2017.

Vectren Ohio Gas Rate Case

On March 30, 2018, the Company filed with the PUCO a request for a $34 million increase in its base rates and charges for VEDO’s distribution business in its 17 county service area in west-central Ohio. The requested increase includes the benefit of the TCJA, which decreased the corporate rate from 35 percent to 21 percent. The filing is necessary to extend the DRR mechanism beyond 2017 through completion of the accelerated replacement program, and to recover the costs of capital investments made over the past ten years, much of which has been deferred as part of the Company’s capital expenditure program under Ohio House Bill 95. The filing also addresses the recovery of the current Ohio House Bill 95 regulatory asset balance, and a proposed mechanism to recover future Ohio House Bill 95 deferrals. The Company expects the PUCO staff to file its report, including recommendations, in the third quarter of 2018 and issue an order by early 2019.

Pipeline and Hazardous Materials Safety Administration (PHMSA)

In March 2016, PHMSA published a notice of proposed rulemaking (NOPR) on the safety of gas transmission and gathering lines. The proposed rule addresses many of the remaining requirements of the 2011 Pipeline Safety Act, with a particular focus on extending integrity management rules to address a much larger portion of the natural gas infrastructure and adds requirements to address broader threats to the integrity of a pipeline system. The Company continues to evaluate the impact these proposed rules will have on its integrity management programs and transmission and distribution systems. Progress on finalizing the rule continues to work through the administrative process. The rule is expected to be finalized in 2019 and the Company believes the costs to comply with the new rules would be considered federally mandated and therefore should be recoverable under Senate Bill 251 in Indiana and eligible for deferral under House Bill 95 in Ohio.

Electric Rate & Regulatory Matters

Electric Requests for Recovery under Senate Bill 560

The provisions of Senate Bill 560, as described in the Gas Rate & Regulatory Matters footnote for gas projects, are the same for qualifying electric projects. On February 23, 2017, the Company filed for authority to recover costs related to its electric system modernization plan, using the mechanism allowed under Senate Bill 560. The electric system modernization plan includes investments to upgrade portions of the Company's network of substations, transmission and distribution systems, to enhance reliability and allow the grid to accept advanced technology to improve the information and service provided to customers.

On September 20, 2017, the IURC issued an Order approving the Company's electric system modification as reflected in the settlement agreement reached between the Company, the OUCC and a coalition of industrial customers. The settlement agreement includes defined annual caps on recoverable capital investments. The settlement agreement also addresses how the eligible costs would be recoverable in rates, with a cap on the residential and small general service fixed monthly charge per customer in each semi-annual filing. The remaining costs to residential and small general service customers would be recovered via a volumetric energy charge. The settlement agreement removed advanced metering infrastructure (AMI or digital meters) from the plan. However, deferral of the costs for AMI was agreed upon in the settlement whereby the company can move forward with deployment in the near-term. The request for cost recovery for the AMI project will not occur until the next base rate review proceeding, which is expected to be filed by the end of 2023. In that proceeding, settling parties have agreed not to oppose inclusion of the AMI project in rate base.

On August 1, 2017, the Company filed with the IURC its initial request for approval of the revenue requirement associated with a capital investment of $7.1 million through April 30, 2017. On December 20, 2017, the IURC issued an Order approving the initial rates necessary to begin cash recovery of 80 percent of the revenue requirement, inclusive of return, with the remaining 20 percent deferred for recovery in the utility's next general rate case. On February 1, 2018, the Company submitted its second semi-annual filing, seeking approval of the recovery in rates of investments made of approximately $31 million through October 31, 2017. As of March 31, 2018 and December 31, 2017, the Company has regulatory assets related to the Electric TDSIC plan totaling $4.5 million and $4.3 million, respectively.

SIGECO Electric Environmental Compliance Filing
On January 28, 2015, the IURC issued an Order approving the Company's request for approval of capital investments in its coal-fired generation units to comply with new EPA mandates related to mercury and air toxic standards (MATS) effective in 2015 and to address an outstanding Notice of Violation (NOV) from the EPA pertaining to its A.B. Brown generating station sulfur trioxide emissions. 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.

As of 2017, the Company has completed investments of $30 million on equipment to control mercury in both air and water emissions, and $40 million to address the issues raised in the NOV. The Order approved the Company's request for deferred accounting treatment, as supported by provisions under Indiana Senate Bill 29 and Senate Bill 251. The accounting treatment includes the deferral of depreciation and property tax expense related to these investments, accrual of post-in-service carrying costs, and deferral of incremental operating expenses related to compliance with these standards. The initial phase of the projects went into service in 2014, with the remaining investment going into service in 2016. As of March 31, 2018, the Company has approximately $14.0 million deferred related to depreciation and operating expenses, and $5.1 million deferred related to post-in-service carrying costs. MATS compliance was required beginning April 16, 2015 and the Company continues to operate in full compliance with the MATS rule.

On February 20, 2018, the Company filed a request to commence recovery, under Senate Bill 251, of its already approved investments associated with the MATS and NOV Compliance Projects, including recovery of the authorized deferred balance. As proposed, recovery would reflect 80 percent of the authorized costs, including a return, recovery of depreciation and incremental operating expenses, and recovery of the prior deferred balance over a proposed period of 15 years. The remaining 20 percent will be deferred until the Company’s next base rate proceeding. The Company expects an order in the first half of 2019 since filed as a part of the electric generation transition plan case discussed below.

SIGECO Electric Demand Side Management (DSM) Program Filing

On March 28, 2014, Indiana Senate Bill 340 was signed into law. The legislation allows for industrial customers to opt out of participating in energy efficiency programs and as a result of this legislation, customers representing most of the eligible load have since opted out of participation in the applicable energy efficiency programs.

Indiana Senate Bill 412 (Senate Bill 412) requires electricity suppliers to submit energy efficiency plans to the IURC at least once every three years. Senate Bill 412 also requires the recovery of all program costs, including lost revenues and financial incentives associated with those plans and approved by the IURC. The Company made its first filing pursuant to this bill in June 2015, which proposed energy efficiency programs for calendar years 2016 and 2017. On March 23, 2016, the IURC issued an Order approving the Company’s 2016-2017 energy efficiency plan. The Order provided for cost recovery of program and administrative expenses and included performance incentives for reaching energy savings goals. The Order also included a lost margin recovery mechanism that would have limited recovery related to new programs to the shorter of four years or the life of the installed energy efficiency measure. Prior electric energy efficiency orders did not limit lost margin recovery in this manner. This ruling followed other IURC decisions implementing the same lost margin recovery limitation with respect to other electric utilities in Indiana. The Company appealed this lost margin recovery restriction based on the Company’s commitment to promote and drive participation in its energy efficiency programs.

On March 7, 2017, the Indiana Court of Appeals reversed the IURC finding on the Company's 2016-2017 energy efficiency plan that the four year cap on lost margin recovery was arbitrary and the IURC failed to properly interpret the governing statute requiring it to review the utility's originally submitted DSM proposal and either approve or reject it as a whole, including the proposed lost margin recovery. The case was remanded to the IURC for further proceedings. On June 13, 2017, the Company filed additional testimony supporting the plan. In response to the proposals to cap lost margin recovery, the Company filed supplemental testimony that supported lost margin recovery based on the average measure life of the plan, estimated at nine years, on 90 percent of the direct energy savings attributed to the programs. Testimony of intervening parties was filed on July 26, 2017, opposing the Company's proposed lost margin recovery. An evidentiary hearing was held in September 2017. On December 20, 2017, the Commission issued an order approving the DSM Plan for 2016-2017 including the recovery of lost margins consistent with the Company’s proposal. On January 22, 2018, certain intervening parties initiated an appeal to the Indiana Court of Appeals. The briefs of appealing parties are currently due on May 3, 2018. While no assurance as to the ultimate outcome can be provided, based upon the record of the proceedings, as well as the findings in the Commission’s order, the Company expects to prevail in this appeal.

On April 10, 2017, the Company submitted its request for approval to the IURC of its Energy Efficiency Plan for calendar years 2018 through 2020. Consistent with prior filings, this filing included a request for continued cost recovery of program and administrative expenses, including performance incentives for reaching energy savings goals and continued recovery of lost margins consistent with the modified proposal in the 2016-2017 plan. Filed testimony of intervening parties was received on July 26, 2017, opposing the Company's proposed lost margin recovery. An evidentiary hearing was held in September 2017. On December 28, 2017, the Commission issued an order approving the 2018 through 2020 Plan, inclusive of recovery of lost margins consistent with the Order issued on December 20, 2017. On January 26, 2018, certain intervening parties initiated an appeal to the Indiana Court of Appeals. The briefs of appealing parties are currently due on May 3, 2018. While no assurance as to the ultimate outcome can be provided, based upon the record of the proceedings, as well as the findings in the Commission’s order, the Company expects to prevail in this appeal.

For the three months ended March 31, 2018 and 2017, the Company recognized electric utility revenue of $3.1 million and $3.0 million, respectively, associated with lost margin recovery approved by the Commission.

FERC Return on Equity (ROE) Complaints

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

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

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

The Company has reflected these results in its financial statements. As of March 31, 2018, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $132.6 million at March 31, 2018.

On April 14, 2017, the U.S. Court of Appeals for the District of Columbia circuit vacated the FERC Opinion in a prior case that established a new methodology for calculating ROE. This methodology was utilized in the final order in the Company's first complaint case, and the initial decision in the Company's second complaint case. The Appeals Court stated that FERC did not prove the existing ROE was not just and reasonable, failed to provide any reasoned basis for their selected ROE, and remanded to the FERC for further justification of its ROE calculation. The Company will continue to monitor this proceeding and evaluate any potential impacts on the Company's complaint cases but would not expect them to be material.

Electric Generation Transition Plan

As required by Indiana regulation, the Company filed its 2016 Integrated Resource Plan (IRP) with the IURC on December 16, 2016. The State requires each electric utility to perform and submit an IRP that uses economic modeling to consider the costs and risks associated with available resource options to provide reliable electric service for the next twenty-year period. During 2016, the Company held three public stakeholder meetings to gather input and feedback as well as communicate results of the IRP process as it progressed. In developing its IRP, the Company considered both the cost to continue operating its existing generation units in a manner that complies with current and anticipated future environmental requirements, as well as various resource alternatives, such as the use of energy efficiency programs and renewable resources as part of its overall generation portfolio. After submission, parties to the IRP provided comments on the plan. While the IURC does not approve or reject the IRP, the process involves the issuance of a staff report that provides comments on the IRP. The final report was issued on November 2, 2017. The Company has taken the comments provided in the report into consideration in its generation transition plan.

The Company’s IRP considered a broad range of potential resources and variables and is focused on ensuring it offers a reliable, reasonably priced generation portfolio as well as a balanced energy mix. Consistent with the recommendations presented in the Company’s IRP and as a direct result of significant environmental investments required to comply with current regulations, the Company plans to retire a significant portion of its generating fleet by the end of 2023. On February 20, 2018, the Company filed a petition seeking authorization from the IURC to construct a new 800-900 MW natural gas combined cycle generating facility to replace this capacity at an approximate cost of $900 million, which includes the cost of a new natural gas pipeline to serve the plant. The Company is requesting a certificate of public convenience and necessity (CPCN) authorizing construction timelines and costs of new generation resources, as well as necessary unit retrofits, to implement the generation transition plan. In that filing, the Company seeks approval of its generation transition plan, including the authority to defer the cost of new generation, including the ability to accrue AFUDC and defer depreciation until the facility is placed in base rates.

As a part of this same proceeding, the Company seeks recovery under Senate Bill 251 of costs to be incurred for environmental investments to be made at its F.B. Culley generating plant to comply with Effluent Limitation Guidelines and Coal Combustion Residuals rules. The F.B. Culley investments, estimated to be approximately $90 million, will begin in 2019 and will allow the F.B. Culley Unit 3 generating facility to comply with environmental requirements and continue to provide generating capacity to the Company’s electric customers. Under Senate Bill 251, the Company is seeking recovery of 80 percent of the approved costs, including a return, using a tracking mechanism, with the remaining 20 percent of the costs deferred for recovery in the Company’s next base rate proceeding.

Intervenors must file testimony by August 10, 2018. Evidentiary hearings are scheduled to commence October 9, 2018. The Company expects an order from the Commission in this proceeding in the first half of 2019.

On August 30, 2017, the IURC issued an Order approving the Company’s request to recover costs related to the construction of three solar projects, using the mechanism allowed under Senate Bill 29, which allows for timely recovery of costs and expenses incurred during the construction and operation of clean energy projects. These investments, presented as part of the Company’s (IRP) submitted in December 2016, allow the Company to add approximately 4 MW of universal solar generation, rooftop solar generation, and 1 MW of battery storage resources to its portfolio. The approved cost of the projects cannot exceed the approximate $16 million estimate submitted by the Company, without seeking further Commission approval.

On February 20, 2018, the Company announced it is finalizing details to install an additional 50 MW of universal solar energy, consistent with its IRP. On May 4, 2018, the Company filed a petition with the IURC requesting a CPCN authorizing construction and authority to recover costs associated with the project pursuant to Senate Bill 29. No procedural schedule has been set, but the Company would expect an order in the first half of 2019.

In addition, the Company intends to continue to offer energy efficiency programs annually. Similarly, as discussed in more detail below, the extension of preliminary compliance deadlines related to ELG implementation are not expected to have a significant impact on the Company’s long term generation transition plan.

On September 21, 2017, the Company and Alcoa agreed to continue the joint ownership and operation of Warrick Unit 4 through 2023. This aligns with the Company's long-term electric generation transition plan, and the expected exit at the end of 2023 is consistent with the IRP which reflects having completed all planned unit retirements and bringing new resources online by that date.

Environmental & Sustainability Matters

The Company initiated a corporate sustainability program in 2012 with the publication of the initial corporate sustainability report. Since that time, the Company continues to develop strategies that focus on environmental, social, and governance (ESG) factors that contribute to the long-term growth of a sustainable business model. The sustainability policies and efforts, and in particular its policies and procedures designed to ensure compliance with applicable laws and regulations, are directly overseen by the Company's Corporate Responsibility and Sustainability Committee, as well as vetted with the Company's Board of Directors. Further discussion of key goals, strategies, and governance practices can be found in the Company’s current sustainability report, at www.vectren.com/sustainability, which received core level certification from the Global Reporting Initiative.

In furtherance of the Company’s commitment to a sustainable business model, and as detailed further below, the Company is transitioning its electric generation portfolio from nearly total reliance on baseload coal to a fully diversified and balanced portfolio of fuels that will provide long-term electric supply needs in a safe and reliable manner while dramatically lowering emissions of carbon and the carbon intensity of its electric generating fleet. If authorized by the Commission, by 2024 the Company plans to construct a new natural gas combined cycle generating facility to replace four coal-fired units totaling over 700 MWs which, when combined with its planned 54 MWs of new renewable generation, will achieve a 60 percent reduction in carbon emissions from 2005 levels and reduce carbon intensity to 980 lbs CO_2 / MMBTU and position the Company to comply with future carbon emission reduction requirements. In addition to diversification of its fuel portfolio, the Company is also seeking authorization to significantly upgrade wastewater treatment for its remaining coal-fired unit and exploring opportunities to continue to recycle ash from its coal ash ponds. This generation diversification strategy aligns with the Company's ongoing investments in new electric infrastructure through the approved $450 million grid modernization program, and is set forth in more detail in the Company's upcoming 2017 corporate sustainability report.

Further, as part of its commitment to a culture of compliance excellence and continuous improvement, the Company continues to enhance its Safety Management System (SMS) which was implemented several years ago. The risk analysis and process review provides valuable input into the assessment process used to drive the ongoing infrastructure improvement plans being executed by the Company’s gas and electric utilities.

The Company is subject to extensive environmental regulation pursuant to a variety of federal, state, and municipal laws and regulations. These environmental regulations impose, among other things, restrictions, liabilities, and obligations in connection with the storage, transportation, treatment, and disposal of hazardous substances and limit airborne emissions from electric generating facilities including particulate matter, sulfur dioxide (SO2), nitrogen oxide (NOx), and mercury, among others. Environmental legislation and regulation also requires that facilities, sites, and other properties associated with the Company's operations be operated, maintained, abandoned, and reclaimed to the satisfaction of applicable regulatory authorities. The Company's current costs to comply with these laws and regulations are significant to its results of operations and financial condition. Similar to the costs associated with federal mandates in the Pipeline Safety Law, Senate Bill 251 is also applicable to federal environmental mandates impacting SIGECO's electric operations.

Coal Ash Waste Disposal, Ash Ponds and Water

Coal Combustion Residuals Rule

In April 2015, the EPA finalized its Coal Combustion Residuals (CCR) rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The final rule allows beneficial reuse of ash and the majority of the ash generated by the Company’s generating plants will continue to be reused. As it relates to the CCR Rule, the Water Infrastructure Improvements for the Nation (WIIN) Act was passed in December 2016 by Congress that would provide for enforcement of the federal program by states under approved state programs rather than citizen suits. Additionally, aspects of the CCR rule are currently being challenged by multiple parties in judicial review proceedings. In August 2017, the EPA issued guidance to states to clarify their ability to implement the Federal CCR rule through state permit programs as allowed in the WIIN Act legislation. Alternative compliance mechanisms for groundwater, corrective action and other areas of the rule could be granted under the regulatory oversight of a state enforced program. On September 14, 2017, the EPA announced its intent to reconsider portions of the Federal CCR rule in line with the guidance issued to states. On March 15, 2018, EPA published its proposed reconsideration of certain provisions of the existing CCR rule to bring the rule consistent with the WIIN Act. The Company does not anticipate the reconsideration to change its current plans for pond closure as announced in its generation transition plan. While the state program development and EPA reconsideration move forward, the existing CCR compliance obligations remain in effect.

Under the existing CCR rule, the Company is required to complete a series of integrity assessments, including seismic modeling given the Company’s facilities are located within two seismic zones, and groundwater monitoring studies to determine the remaining service life of the ponds and whether a pond must be retrofitted with liners or closed in place, with bottom ash handling conversions completed. In late 2015, using general utility industry data, the Company prepared cost estimates for the retirement of the ash ponds at the end of their useful lives, based on its interpretation of the closure alternatives contemplated in the final rule. The resulting estimates ranged from approximately $35 million to $80 million. These estimates contemplated final capping and monitoring costs of the ponds at both F.B. Culley and A.B. Brown generating stations. These rules are not applicable to the Company's Warrick generating unit, as this unit has historically been part of a larger generating station that predominantly serves an adjacent industrial facility. In March 2018, the Company posted to its public website a first report of preliminary groundwater monitoring data in accordance with the requirements of the CCR rule. This data preliminarily suggests potential groundwater impacts very close to the Company's ash impoundments, and further analysis is ongoing; however, at this time the Company does not believe that there are any impacts to public or private drinking water sources.

Since 2015, the Company continues to refine site specific estimates and now estimates the costs to be in the range of $45 million to $135 million. Significant factors impacting the resulting cost estimates include the closure time frame and the method of closure. Current estimates contemplate complete removal under the assumption of beneficial reuse of the ash at A.B. Brown, as well as implications of the Company's generation transition plan. Ongoing analysis, the continued refinement of assumptions, or the inability to beneficially reuse the ash, either from a technological or economical perspective, could result in estimated costs in excess of the current range.

As of March 31, 2018, the Company has recorded an approximate $40 million asset retirement obligation (ARO). The recorded ARO reflects the present value of the approximate $45 million in estimated costs in the range above. These assumptions and estimations are subject to change in the future and could materially impact the amount of the estimated ARO.

In order to maintain current operations of the ponds, the Company spent approximately $17 million on the reinforcement of the ash pond dams and other operational changes in 2016 to meet the more stringent 2,500 year seismic event structural and safety standard in the CCR rule.

Effluent Limitation Guidelines (ELG)

Under the Clean Water Act, the EPA sets technology-based guidelines for water discharges from new and existing electric generation facilities. In September 2015, the EPA finalized revisions to the existing steam electric ELG setting stringent technology-based water discharge limits for the electric power industry. The EPA focused this rulemaking on wastewater generated primarily by pollution control equipment necessitated by the comprehensive air regulations, specifically setting strict water discharge limits for arsenic, mercury and selenium for scrubber waste waters. The ELG will be implemented when existing water discharge permits for the plants are renewed, with compliance activities expected to commence where operations continue, within the 2018-2023 time frame. The ELG work in tandem with the aforementioned CCR requirements, effectively prohibiting the use of less costly lined sediment basin options for disposal of coal combustion residuals, and virtually mandate conversions to dry bottom ash handling.

At the time of ELG finalization, the wastewater discharge permit for the A.B. Brown power plant had an expiration date of October 2016 and, for the F.B. Culley plant, a date of December 2016, and final renewals were issued by the Indiana Department of Environmental Management (IDEM) in February 2017 and March 2017, respectively. As part of the permit renewals, the Company requested alternate compliance dates for ELG, which were approved by IDEM. For plants identified in the Company’s IRP to be retired prior to December 31, 2023, the Company has requested those plants would not require new treatment technology, which was approved by IDEM provided the Company notifies IDEM within one year of issuance of the renewal of its intent to retire the unit. For the F.B. Culley 3 plant, the Company requested a 2020 compliance date for dry bottom ash and 2023 compliance date for flue gas desulfurization wastewater, which was approved by IDEM and finalized in the permit renewal. Discussion of these environmental investments at the F.B. Culley 3 plant is included in the generation transition plan in Note 11.

On April 13, 2017, as part of the Administration's regulatory reform initiative, which is focused on the number and nature of regulations, the EPA granted petitions to reconsider the ELG rule, and indicated it would stay the current implementation deadlines in the rule during the pendency of the reconsideration. The EPA has also sought a stay of the current judicial review litigation in federal district court. The court has yet to grant the indefinite stay sought by EPA, and instead placed the parties on a periodic status update schedule. On September 13, 2017, EPA finalized a rule postponing certain interim compliance dates by two years, but did not postpone the final compliance deadline of December 31, 2023. As the Company does not currently have short-term ELG implementation deadlines in its recently renewed wastewater discharge permits, the Company does not anticipate immediate impacts from the EPA’s two-year extension of preliminary implementation deadlines due to the longer compliance time frames granted by IDEM, and will continue to work with IDEM to evaluate further implementation plans. Moreover, the Company believes the two year extension of the ELG preliminary implementation deadlines and reconsideration process does not impact its generation transition plan as modeled in the IRP because the final compliance deadline of December 31, 2023 is still in place and enhanced wastewater treatment for scrubber discharge water will still be required by a reconsidered ELG rule even if the EPA revises stringency levels.

Cooling Water Intake Structures

Section 316(b) of the Clean Water Act requires generating facilities use the "best technology available" (BTA) to minimize adverse environmental impacts on a body of water. More specifically, Section 316(b) is concerned with impingement and entrainment of aquatic species in once-through cooling water intake structures used at electric generating facilities. A final rule was issued by the EPA on May 19, 2014. The final rule does not mandate cooling water tower retrofits but requires that IDEM conduct 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 the Company's facilities. The Company is currently undertaking the required ecological studies and anticipates timely compliance in 2021-2022. To comply, the Company believes capital investments will likely be in the range of $4 million to $8 million.

Air Quality

Ozone NAAQS

On November 26, 2014, the EPA proposed to tighten the current National Ambient Air Quality Standard (NAAQS) for ozone from the current standard of 75 parts per billion (ppb) to a level within the range of 65 to 70 ppb. On October 1, 2015, the EPA finalized a new NAAQS for ozone at the high end of the range, or 70 ppb. On September 16, 2016, Indiana submitted its initial determination to the EPA recommending counties in southwest Indiana, specifically Vanderburgh, Posey and Warrick, be declared in attainment of the new more stringent ozone standard based upon air monitoring data from 2014-2016. In November 2017, EPA finalized its designations of Vanderburgh, Posey, and Warrick counties as being in attainment with the current 70 ppb standard.

One Hour SO2 NAAQS

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

Climate Change and Carbon Strategy

The Company, along with the Company's parent, remains committed to responsible environmental stewardship and conservation efforts. The generation transition plan, as set forth in its generation and compliance filing, is a balanced approach toward environmental stewardship and conservation goals, supplying service at a reasonable cost, and operating in compliance with water, air and solid waste regulations, while dramatically reducing the Company's carbon emission from its electric generating fleet. The generation transition plan will result in a 60 percent reduction in carbon emissions from 2005 to 2024 even in the absence of a mandatory greenhouse gas reduction requirement. While the status of the Clean Power Plan (CPP) regulation is uncertain given the legal challenges it faces and pending proposal to repeal the CPP which, if finalized, would likely result in more litigation, the Company's generation transition plan positions it to comply with the CPP, its replacement rule, or future carbon legislation. Moreover, the Company's actions in reducing its carbon emissions 60 percent from 2005 levels by 2024 is consistent with the international community's goal of preventing global temperatures from rising more than two degrees Celsius by the year 2100.

While regulatory uncertainties predominate with respect to the status of the CPP, the Company continues to believe that Congress should set a broad national climate change policy with the following elements:

- An inclusive scope that involves all sectors of the economy and sources of greenhouse gases, and recognizes early actions and investments made to mitigate greenhouse gas emissions;
- Provisions for enhanced use of renewable energy sources as a supplement to baseload generation including effective energy conservation, demand side management, and generation efficiency measures;
- Inclusion of incentives for research and development and investment in advanced clean coal technology; and
-

A strategy supporting alternative energy technologies and biofuels and continued increase in the domestic supply of natural gas and oil to reduce dependence on foreign oil.

Current Initiatives to Increase Conservation & Reduce Emissions

Even in the absence of a federal mandatory requirement to reduce greenhouse gases, the Company is committed to a policy that reduces greenhouse gas emissions and conserves energy usage. Evidence of this commitment includes:

- Since 2005 and through 2017, the Company has achieved a reduction in emissions of CO_2 of 30 percent (on a tonnage basis) through the retirement of F.B. Culley Unit 1, expiration of municipal contracts, electric conservation, the addition of renewable generation, and the installation of more efficient dense pack turbine technology. The three year average emission reduction for the period 2015 to 2017 is 35 percent from 2005 levels.
- Focusing the Company’s mission statement and purpose on corporate sustainability and the need to help customers conserve and manage energy costs. Vectren's annual sustainability report continues to receive Core level certification by the Global Reporting Initiative and demonstrates the Company's commitment to sustainability and transparency in operations. The Company's current sustainability report can be found at www.vectren.com/sustainability;
- Implementing home and business energy efficiency initiatives in the Company’s Indiana and Ohio gas utility service territories such as offering rebates on high efficiency furnaces, programmable thermostats, and insulation and duct sealing;
- Implementing home and business energy efficiency initiatives in the electric service territory such as rebate programs on central air conditioning units, LED lighting, home weatherization and energy audits;
- Building a renewable energy portfolio to complement base load generation in advance of mandated renewable energy portfolio standards;
- Evaluating potential carbon requirements with regard to new generation, other fuel supply sources, and future environmental compliance plans;
- Further reducing the Company’s carbon footprint by building a more sustainable vehicle fleet with lower overall fuel consumption;
- Reducing methane emissions through becoming a founding partner in the EPA Natural Gas STAR Methane Challenge Program. The Company's primary method for reducing methane emissions is through continued replacement of bare steel and cast iron gas distribution pipeline assets; and
- Working with the Company’s gas supply administrator in Indiana to maximize the amount of natural gas delivered to our customers that has been sourced from members of The Environmental Partnership, an organization that includes many of the major oil and gas producers in the U.S and who have committed to continuously improving the industry’s environmental performance.

Clean Power Plan

On August 3, 2015, the EPA released its final Clean Power Plan rule (CPP) which required a 32 percent reduction in carbon emissions from 2005 levels. This would result in a final emission rate goal for Indiana of 1,242 lb CO_2/MWh to be achieved by 2030 and implemented through a state implementation plan. The final rule was published in the Federal Register on October 23, 2015, and that action was immediately followed by litigation initiated by Indiana and 23 other states as a coalition challenging the rule. In January 2016, the reviewing court denied the states’ and other parties requests to stay the implementation of the CPP pending completion of judicial review. On January 26, 2016, 29 states and state agencies, including the 24 state coalition referenced above, filed a request for immediate stay of implementation of the rule with the U.S. Supreme Court. On February 9, 2016, the U.S. Supreme Court granted the stay request to delay the implementation of the regulation while being challenged in court. Oral argument was held in September 2016. The stay will remain in place while the lower court concludes its review. In March 2017, as part of the ongoing regulatory reform efforts of the Administration, the EPA filed a motion with the U.S. Court of Appeals for the District of Columbia circuit to suspend litigation pending the EPA’s reconsideration of the CPP rule, which was granted on April 28, 2017. Moreover, as indicated above, in October 2017, EPA published its proposal to repeal the CPP. Comments to the repeal proposal were due in April 2018. EPA's repeal proposal was quickly followed by an advanced notice of proposed rulemaking intended to solicit public comments on issues related to formulating a CPP replacement rule, which were similarly due in April 2018. Repeal without replacement of the CPP could create potential litigation risk arising from the absence of direct federal regulation in this area that courts have previously determined preempt common law nuisance claims.

Impact of Legislative Actions & Other Initiatives

At this time, compliance costs and other effects associated with reductions in GHG emissions or obtaining renewable energy sources remain uncertain. However, Vectren's generation transition plan, as set forth in its electric generation and compliance filing, will achieve 60 percent reductions in 2005 GHG emission levels by 2025, positioning the Company to comply with future regulatory or legislative actions with respect to mandatory GHG reductions.

In addition to the federal programs, the United States and 194 other countries agreed by consensus to limit GHG emissions beginning after 2020 in the 2015 United Nations Framework Convention on Climate Change Paris Agreement. The United States has proposed a 26-28 percent GHG emission reduction from 2005 levels by 2025. The Administration has indicated it intends to withdraw the United States' participation; however the Agreement provides that parties cannot petition to withdraw until November 2019. Since 2005 through 2017, the Company has achieved reduced emissions of $CO2$ by an average of 35 percent (on a tonnage basis), and will increase that total to 60 percent at the conclusion of its generation transition plan, well above the 32 percent reduction that would be required under the CPP. While the litigation and the EPA's reconsideration of the CPP rules remains uncertain, the Company will continue to monitor regulatory activity regarding GHG emission standards that may affect its electric generating units.

Manufactured Gas Plants

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

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

The Company has accrued the estimated costs for further investigation, remediation, groundwater monitoring, and related costs for the sites. While the total costs that may be incurred in connection with addressing these sites cannot be determined at this time, the Company has recorded cumulative costs that it has incurred or reasonably expects to incur totaling approximately $44.2 million ($23.9 million at Indiana Gas and $20.3 million at SIGECO). The estimated accrued costs are limited to the Company’s share of the remediation efforts and are therefore net of exposures of other potentially responsible parties (PRP).

With respect to insurance coverage, Indiana Gas has received approximately $20.8 million from all known insurance carriers under insurance policies in effect when these plants were in operation. Likewise, SIGECO has settlement agreements with all known insurance carriers and has received approximately $15.7 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 both March 31, 2018 and December 31, 2017, approximately $2.5 million 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 Standards

Leases

In February 2016, the FASB issued new accounting guidance for the recognition, measurement, presentation and disclosure of leasing arrangements. This ASU requires the recognition of lease assets and liabilities for those leases currently classified as operating leases while also refining the definition of a lease. In addition, lessees will be required to disclose key information about the amount, timing, and uncertainty of cash flows arising from leasing arrangements. This ASU is effective for the interim and annual reporting periods beginning January 1, 2019 and is required to be applied using a modified retrospective approach. In January 2018, the FASB issued amendments to the new lease standard, ASU No. 2018-01, allowing an entity to elect not to assess whether certain land easements are, or contain, leases when transitioning to the new lease standard. The Company is currently evaluating the standard to determine the impact it will have on the financial statements and will adopt the guidance effective January 1, 2019.

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

Financial Condition

Utility Holdings funds the short-term and long-term financing needs of its utility subsidiaries. The Company's parent does not guarantee the Company's debt. Outstanding long-term and short-term borrowing arrangements are jointly and severally guaranteed by SIGECO, Indiana Gas, and VEDO. The guarantees are full and unconditional and joint and several, and the Company has no subsidiaries other than the subsidiary guarantors. Information about the subsidiary guarantors as a group is included in Note 4 to the condensed consolidated financial statements. Long-term debt and short-term obligations outstanding at March 31, 2018 approximated $1.195 billion and $180 million, respectively. Additionally, prior to the Company's formation, Indiana Gas and SIGECO funded their operations separately, and therefore, have long-term debt outstanding funded solely by their operations. SIGECO will also occasionally issue new tax exempt debt to fund qualifying pollution control capital expenditures. Total Indiana Gas and SIGECO long-term debt, including current maturities, outstanding at March 31, 2018 was approximately $384 million.

The Company’s operations have historically been the primary source for Vectren’s common stock dividends.

The credit ratings of the senior unsecured debt of the Company, SIGECO and Indiana Gas, at March 31, 2018, were A-/A2, as rated by S&P Global Ratings (S&P Global) and Moody’s Investor Services (Moody’s), respectively. The credit ratings on SIGECO's secured debt were A/Aa3. The Company's commercial paper had a credit rating of A-2/P-1. On March 9, 2018, S&P
Global affirmed its credit ratings, but changed the Company's and subsidiaries' outlook from stable to negative, citing the impacts of tax reform as the primary driver. On April 24, 2018, S&P Global reaffirmed its current ratings, and as a result of the Merger, it placed the Company's and subsidiaries on negative watch, which means closely monitored for potential near term changes in its credit ratings. On April 25, 2018, Moody's reaffirmed its current credit ratings and stable outlook. 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. S&P Global 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 to long-term capitalization ratio was 53 percent and 52 percent as of March 31, 2018 and December 31, 2017, respectively. Long-term capitalization includes long-term debt, including current maturities, as well as common shareholder’s equity.

Both long-term and short-term borrowing arrangements contain customary default provisions; restrictions on liens, sale-leaseback transactions, mergers or consolidations, and sales of assets; and restrictions on leverage, among other restrictions. Multiple debt agreements contain a covenant that the ratio of consolidated total debt to consolidated total capitalization will not exceed 65 percent. As of March 31, 2018, the Company was in compliance with all debt covenants.

Available Liquidity

The Company's A-/A2 investment grade credit ratings have allowed it to access the capital markets as needed, and as evidenced by past financing transactions, the Company believes it will have the ability to continue to do so. The Company anticipates funding future capital expenditures and dividends principally through internally generated funds, supplemented with incremental external financing. Access to both the short-term and long-term capital markets is expected to be a significant source of funding for capital requirements as the resources required for capital investment remain uncertain for a variety of factors including, but not limited to, uncertainty in environmental and safety policy and regulations and growth in gas and electric infrastructure. To the extent that events beyond the Company's control create uncertainty in capital markets, cost of capital and ability to access capital markets may be impacted.

Utility Holdings routinely seeks approval at the IURC and the PUCO for long-term financing authority at the individual utility level. This authority allows for the flexibility for each utility to issue debt and equity securities to third parties or to issue debt and equity securities to Utility Holdings and thus receive some of the proceeds from various Utility Holdings issuances to third parties on the same terms as those obtained by Utility Holdings. The majority of the long-term debt needs of the utilities is expected to be met through these debt issuances by Utility Holdings, some or all of which are then reloaned to the individual utilities. On June 21, 2017, an Order for long-term financing authority of $70 million of long-term debt and $65 million of equity financing was received from the PUCO for VEDO and expires in June 2018. On February 22, 2017, orders for long-term financing authority of $160 million and $200 million of long-term debt, and $120 million and $180 million of equity financing, were received from the IURC for SIGECO and Indiana Gas, respectively. These orders expire in March 2019.

SIGECO Variable Rate Tax-Exempt Bonds

On March 1, 2018 and May 1, 2018, the Company, through SIGECO, executed first and second amendments to a Bond Purchase and Covenants Agreement originally signed in September 2017. These amendments provided SIGECO the ability to remarket bonds that were callable from current bondholders on those dates. Pursuant to these amendments, lenders purchased the following SIGECO bonds on March 1 and May 1, respectively:

- 2013 Series A Notes with a principal of $22.2 million and final maturity date of March 1, 2038; and
- 2013 Series B Notes with a principal of $39.6 million and final maturity date of May 1, 2043.

Prior to the call, the 2013 Series A Notes had an interest rate of 4.0% and the 2013 Series B Notes had an interest rate of 4.05%. The bonds converted to a variable rate based on the one month LIBOR through May 1, 2023.

The Company has now remarketed $152 million of tax exempt bonds through the Bonds Purchase and Covenants Agreement, which is the agreement’s full capacity. Bonds remarketed through the Bond Purchase and Covenants Agreement in 2017 were:

- 2013 Series C Notes with a principal of $4.6 million and final maturity date of January 1, 2022;
- 2013 Series D Notes with a principal of $22.5 million and final maturity date of March 1, 2024;
- 2013 Series E Notes with a principal of $22.0 million and final maturity date of May 1, 2037; and
- 2014 Series B Notes with a principal of $41.3 million and final maturity date of July 1, 2025.

These bonds also have variable interest rate based on the one month LIBOR through May 1, 2023.

The Company, through SIGECO, executed forward starting interest rate swaps during 2017 providing that on January 1, 2020, the Company will begin hedging the variability in interest rates on the 2013 Series A, B, and E Notes through final maturity dates. The swaps contain customary terms and conditions and generally provide offset for changes in the one month LIBOR rate. Other interest rate variability that may arise through the Bond Purchase and Covenants Agreement, such as variability caused by changes in tax law or SIGECO’s credit rating, among others, may result in an actual interest rate above or below the anticipated fixed rate. Regulatory orders require SIGECO to include the impact of its interest rate risk management activities, such as gains and losses arising from these swaps, in its cost of capital utilized in rate cases and other periodic filings.

Consolidated Short-Term Borrowing Arrangements

At March 31, 2018, the Company had $400 million of short-term borrowing capacity. As reduced by borrowings and letters of credit outstanding, approximately $214 million was available. These short-term credit facilities were extended in July 2017 and are available through July 2022. As of March 31, 2018, there were $5.2 million letters of credit outstanding under the Utility Group facility.

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 as of March 31, 2018:

(In millions)	2018	2017
As of March 31		
Balance Outstanding	$180.4	$101.4
Weighted Average Interest Rate	2.31%	1.14%
Year to Date Average - March 31		
Balance Outstanding	$161.0	$152.6
Weighted Average Interest Rate	1.89%	0.96%
Maximum Month End Balance Outstanding	$185.6	$186.0

Impact of Tax Reform on Liquidity

The Company has realized cash flow benefits from tax legislation, such as the Protecting Americans from Tax Hikes (Path Act) enacted in 2015, which allowed for immediate expensing of 50 percent of capital expenditures through 2017 for tax purposes. Such accelerated expense recognition reduced tax payments due to the government. The TCJA enacted on December 22, 2017, which eliminates the accelerated expensing provisions for regulated utilities and reduces the corporate tax rate to 21 percent, has reduced, and will continue to reduce liquidity by 1) reducing the Utility Group’s ability to accelerate expense for capital expenditures for tax purposes and 2) reducing cash collected from customers due to the lower tax rate. The Company further expects that the reduced federal corporate income tax rate could result in additional cash available from the nonutility operations to help fund utility capital expenditures or other operating needs.

Long-Term Borrowing Facilities

The Merger would constitute a “Change of Control” under the note agreements pursuant to which Senior Notes issued by Utility Holdings in an aggregate principal amount of $1.025 billion were issued. While the Merger would not result in an event of default under such note agreements, upon the consummation of the Merger, Utility Holdings would be required to offer to repurchase these notes at 100% of the principal amount thereof plus accrued interest.

Potential Uses of Liquidity

Pension Funding Obligations

For the three months ended March 31, 2018, the Company's parent contributed $3.5 million to its qualified pension plans, a majority of which was funded by the Company. The Company's parent does not anticipate making any additional contributions for the remainder of 2018.

Planned Capital Expenditures

Capital expenditures are estimated at approximately $475 million for the remainder of 2018.

Contractual Obligations

The Company’s contractual obligations primarily consist of debt issued by the Company and its subsidiaries as well as certain plant and nonutility plant purchase commitments. For the three months ended March 31, 2018, there were no significant changes to the Company’s contractual obligations from those identified in the Company’s Annual Report on Form 10-K for the year ended December 31, 2017, other than those which occur in the normal and ordinary course of business and those mentioned below.

The Company's regulated utilities have both firm and non-firm commitments, some of which are between five and twenty year agreements to purchase natural gas, electricity, and coal, as well as certain transportation and storage rights. Costs arising from these commitments, while significant, are pass-through costs, generally collected dollar-for-dollar from retail customers through regulator-approved cost recovery mechanisms.

Comparison of Historical Sources & Uses of Liquidity

Operating Cash Flow

The Company's primary source of liquidity to fund working capital requirements has been cash generated from operations, which totaled $157.8 million and $187.0 million for the three months ended March 31, 2018 and 2017, respectively. The decrease in operating cash flow for the three months ended March 31, 2018 compared to 2017 is driven primarily by the Company’s $35.7 million contribution to the Vectren Foundation, a 501(c)(3) charitable organization, affiliated with, but separate from, Vectren Corporation and reflected in Accounts payable at December 31, 2017 in the Condensed Consolidated Balance Sheets.

Financing Cash Flow

Net cash flow required for financing activities were $30.6 million and $82.0 million during the three months ended March 31, 2018 and 2017, respectively. The increase in financing cash flow for the three months ended March 31, 2018 compared to 2017 is driven primarily by increased short-term borrowings utilized to fund the Vectren Foundation and increased capital expenditures. Financing activity in both periods reflects the payment of dividends to the Company's parent.

Investing Cash Flow

Cash flow required for investing activities was $122.5 million and $107.6 million during the three months ended March 31, 2018 and 2017, respectively. The primary use of cash in both periods reflects expenditures for utility capital expenditures.

Forward-Looking Information

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

Risks Related to the Merger

Important factors that could cause actual results to differ materially from those indicated by the provided forward-looking information include risks and uncertainties relating to:

- The risk that Vectren may be unable to obtain shareholder approval for the proposed transaction.
- The risk that CenterPoint or Vectren may be unable to obtain governmental and regulatory approvals required for the proposed transaction, or that required governmental and regulatory approvals or agreements with other parties interested therein may delay the proposed transaction or may be subject to or impose adverse conditions or costs.
- The occurrence of any event, change or other circumstances that could give rise to the termination of the proposed transaction or could otherwise cause the failure of the proposed transaction to close.
- The risk that a condition to the closing of the proposed transaction or the committed financing may not be satisfied.
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The failure to obtain, or to obtain on favorable terms, any equity, debt or other financing necessary to complete or permanently finance the proposed transaction and the costs of such financing.

- The outcome of any legal proceedings, regulatory proceedings or enforcement matters that may be instituted relating to the proposed transaction.
- The receipt of an unsolicited offer from another party to acquire assets or capital stock of Vectren that could interfere with the proposed transaction.
- The timing to consummate the proposed transaction.
- The costs incurred to consummate the proposed transaction.
- The possibility that the expected cost savings, synergies or other value creation from the proposed transaction will not be realized, or will not be realized within the expected time period.

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- The risk that the companies may not realize fair values from properties that may be required to be sold in connection with the merger.
- The credit ratings of the companies following the proposed transaction.
- Disruption from the proposed transaction making it more difficult to maintain relationships with customers, employees, regulators or suppliers.
- The diversion of management time and attention on the proposed transaction.

Risks Related to the Company

Important factors related to the Company, its affiliates, and its and their operations that could cause actual results to differ materially from those indicated by the provided forward-looking information include risks and uncertainties relating to:

- Factors affecting utility operations such as unfavorable or unusual weather conditions; catastrophic weather-related damage; unusual maintenance or repairs; unanticipated changes to coal and natural gas costs; unanticipated changes to gas transportation and storage costs, or availability due to higher demand, shortages, transportation problems or other developments; environmental or pipeline incidents; transmission or distribution incidents; unanticipated changes to electric energy supply costs, or availability due to demand, shortages, transmission problems or other developments; or electric transmission or gas pipeline system constraints.
- New or proposed legislation, litigation and government regulation or other actions, such as changes in, rescission of or additions to tax laws or rates, pipeline safety regulation and environmental laws and regulations, including laws governing air emissions, carbon, waste water discharges and the handling and disposal of coal combustion residuals that could impact the continued operation, and/or cost recovery of generation plant costs and related assets. Compliance with respect to these regulations could substantially change the operation and nature of the Company’s utility operations.
- Catastrophic events such as fires, earthquakes, explosions, floods, ice storms, tornadoes, terrorist acts, physical attacks, cyber attacks, or other similar occurrences could adversely affect the Company's facilities, operations, financial condition, results of operations, and reputation.
- Approval and timely recovery of new capital investments related to the electric generation transition plan, discussed further herein, including timely approval to build and own generation, ability to meet capacity requirements, ability to procure resources needed to build new generation at a reasonable cost, ability to appropriately estimate costs of new generation, the effects of construction delays and cost overruns, ability to fully recover the investments made in retiring portions of the current generation fleet, scarcity of resources and labor, and workforce retention, development and training.
- Increased competition in the energy industry, including the effects of industry restructuring, unbundling, and other sources of energy.
- Regulatory factors such as uncertainty surrounding the composition of state regulatory commissions, adverse regulatory changes, unanticipated changes in rate-setting policies or procedures, recovery of investments and costs made under regulation, interpretation of regulatory-related legislation by the IURC and/or PUCO and appellate courts that review decisions issued by the agencies, and the frequency and timing of rate increases.
- Financial, regulatory or accounting principles or policies imposed by the Financial Accounting Standards Board; the Securities and Exchange Commission; the Federal Energy Regulatory Commission; state public utility commissions; state entities which regulate electric and natural gas transmission and distribution, natural gas gathering and processing, electric power supply; and similar entities with regulatory oversight.
- Economic conditions including the effects of inflation, commodity prices, and monetary fluctuations.
- Economic conditions, including increased potential for lower levels of economic activity; uncertainty regarding energy prices and the capital and commodity markets; volatile changes in the demand for natural gas, electricity;

economic impacts of changes in business strategy on both gas and electric large customers; lower residential and commercial customer counts; variance from normal population growth and changes in customer mix; and higher operating expenses.

- Volatile natural gas and coal commodity prices and the potential impact on customer consumption, uncollectible accounts expense, unaccounted for gas and interest expense.
- Volatile oil prices and the potential impact on customer consumption and price of other fuel commodities.
- Direct or indirect effects on the Company's business, financial condition, liquidity and results of operations resulting from changes in credit ratings, changes in interest rates, and/or changes in market perceptions of the utility industry and other energy-related industries.

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

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to various business risks associated with commodity prices, interest rates, and counter-party credit. These financial exposures are monitored and managed by the Company as an integral part of its overall risk management program. The Company's risk management program includes, among other things, the occasional use of derivatives. The Company will, from time to time, execute derivative contracts in the normal course of operations while buying and selling commodities and when managing interest rate risk.

The Company's parent has 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 Company's 2017 Form 10-K and is therefore not presented herein.

ITEM 4. CONTROLS AND PROCEDURES

Changes in Internal Controls over Financial Reporting

During the quarter ended March 31, 2018, there have been no changes to the Company's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of March 31, 2018, the Company conducted an evaluation under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer of the effectiveness and the design and operation of the Company's disclosure controls and procedures. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective as of March 31, 2018, 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 likely to have a material adverse effect on its financial position, results of operations, or cash flows. See the notes to the consolidated financial statements regarding commitments and contingencies, environmental matters, and rate & 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. Other than the merger-related risk factors noted below, the Company’s risk factors have not materially changed from the information set forth in Item 1A Risk Factors included in the Company's 2017 Form 10-K and are therefore not presented herein.

Risks Associated with Merger

Vectren cannot provide any assurance that the Merger will be completed. Failure to complete the Merger could negatively affect the trading price of Vectren's common stock and the Company's future business and financial results.

Consummation of the Merger is subject to various conditions, including: (1) approval of the shareholders of Vectren (2) expiration or termination of the applicable Hart-Scott– Rodino Act waiting period, (3) receipt of all required regulatory and statutory approvals without the imposition of a "Burdensome Condition," (4) absence of any law or order prohibiting the consummation of the Merger and (5) other customary closing conditions, including (a) subject to materiality qualifiers, the accuracy of each party's representations and warranties, (b) each party's compliance in all material respects with its obligations and covenants under the Merger Agreement and (c) the absence of a material adverse effect with respect to Vectren and its subsidiaries.

The conditions to the Merger may not be satisfied and the Merger Agreement could be terminated. In addition, satisfying the conditions to the Merger may take longer than Vectren and CenterPoint expect. The occurrence of any of these events individually or in combination could negatively affect the trading price of the Vectren's common stock and the Company's future business and financial results and subject the Company to the following:

- negative reactions from the financial markets, including declines in the price of Vectren's common stock due to the fact that the current price may reflect a market assumption that the Merger will be completed;

- performance shortfalls and missed opportunities as a result of the diversion of the Company's management's attention by the Merger; and

- potential payments by Vectren to CenterPoint for damages, or if the Merger Agreement is terminated under certain circumstances, a termination fee of $150 million.

The Company will be subject to business uncertainties and contractual restrictions while the Merger is pending, which could adversely affect the Company's business.

Uncertainty about the impact of the Merger, including on employees and customers, may have an adverse effect on the Company. These uncertainties may impair the Company's ability to attract, retain and motivate personnel, and could cause customers, suppliers and others that deal with the Company to seek to change existing business relationships with the Company. If employees depart, the Company's business could be harmed. In addition, the Merger Agreement restricts the Company, without the consent of CenterPoint, from taking specified actions until the Merger is completed or the Merger Agreement terminates. These restrictions may prevent the Company from pursuing otherwise attractive business opportunities and making other changes to the Company's business.

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

2.1	Agreement and Plan of Merger by and among Vectren Corporation, Pacer Merger Sub, Inc. and CenterPoint Energy, Inc., dated as of April 21, 2018 (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K, dated April 23, 2018, File No. 1-15467)
4.1	Joinder and First Amendment to Bond Purchase and Covenants Agreement dated March 1, 2018 among SIGECO, the lenders party thereto and PNC Bank, National Association, as Administrative Agent. (filed and designated in Form 8-K, dated March 1, 2018, File No. 1-15467, as Exhibit 4.1)
4.2	Second Amendment to Bond Purchase and Covenants Agreement dated May 1, 2018 among SIGECO, the lenders party thereto and PNC Bank, National Association, as Administrative Agent. (filed and designated in Form 8-K, dated March 1, 2018, File No. 1-15467, as Exhibit 4.2)
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
May 9, 2018	/s/ M. Susan Hardwick M. Susan Hardwick Executive Vice President and Chief Financial Officer (Signing on behalf of the registrant and as Principal Accounting & Financial Officer)

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