VECTREN UTILITY HOLDINGS INC
Form 10-Q
May 15, 2017

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, 2017
OR

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

For the transition period from __________________ to __________________

Commission file number: 1-16739

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

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

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

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

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

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

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

| | |
|---|---|
| Large accelerated filer o | Accelerated filer o |
| Non-accelerated filer ý (Do not check if a smaller reporting company) | Smaller reporting company o |
| 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 28, 2017 |
| 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:<br>One Vectren Square<br>Evansville, Indiana 47708 | Phone Number:<br>(812) 491-4000 | Investor Relations Contact:<br>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, 2017 | December 31, 2016 |
|---|---|---|
| ASSETS | | |
| Current Assets | | |
| Cash & cash equivalents | $ 6.8 | $ 9.4 |
| Accounts receivable - less reserves of $4.9 & $4.1, respectively | 95.7 | 102.6 |
| Accrued unbilled revenues | 75.9 | 112.0 |
| Inventories | 105.9 | 119.0 |
| Recoverable fuel & natural gas costs | 27.1 | 29.9 |
| Prepayments & other current assets | 20.9 | 38.6 |
| Total current assets | 332.3 | 411.5 |
| Utility Plant | | |
| Original cost | 6,633.9 | 6,545.4 |
| Less: accumulated depreciation & amortization | 2,609.0 | 2,562.5 |
| Net utility plant | 4,024.9 | 3,982.9 |
| Investments in unconsolidated affiliates | 0.2 | 0.2 |
| Other investments | 22.5 | 21.3 |
| Nonutility plant - net | 165.2 | 164.8 |
| Goodwill | 205.0 | 205.0 |
| Regulatory assets | 222.2 | 206.2 |
| Other assets | 48.2 | 49.0 |
| TOTAL ASSETS | $ 5,020.5 | $ 5,040.9 |

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, 2017 | December 31, 2016 |
|---|---|---|
| LIABILITIES & SHAREHOLDER'S EQUITY | | |
| Current Liabilities | | |
| Accounts payable | $ 140.3 | $ 205.4 |
| Payables to other Vectren companies | 22.7 | 25.4 |
| Accrued liabilities | 166.5 | 140.1 |
| Short-term borrowings | 101.4 | 194.4 |
| Current maturities of long-term debt | 49.1 | 49.1 |
| Total current liabilities | 480.0 | 614.4 |
| Long-Term Debt - Net of Current Maturities | 1,331.2 | 1,331.0 |
| | | |
| Deferred Credits & Other Liabilities | | |
| Deferred income taxes | 881.9 | 854.5 |
| Regulatory liabilities | 462.0 | 453.7 |
| Deferred credits & other liabilities | 164.5 | 163.3 |
| Total deferred credits & other liabilities | 1,508.4 | 1,471.5 |
| Commitments & Contingencies (Notes 7 - 10) | | |
| Common Shareholder's Equity | | |
| Common stock (no par value) | 872.7 | 831.2 |
| Retained earnings | 828.2 | 792.8 |
| Total common shareholder's equity | 1,700.9 | 1,624.0 |
| TOTAL LIABILITIES & SHAREHOLDER'S EQUITY | $ 5,020.5 | $ 5,040.9 |

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

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

| | Three Months Ended March 31, | |
|---|---|---|
| | 2017 | 2016 |
| OPERATING REVENUES | | |
| Gas utility | $292.8 | $281.2 |
| Electric utility | 132.1 | 142.1 |
| Other | 0.1 | 0.1 |
| Total operating revenues | 425.0 | 423.4 |
| OPERATING EXPENSES | | |
| Cost of gas sold | 112.9 | 111.6 |
| Cost of fuel & purchased power | 41.2 | 44.2 |
| Other operating | 85.6 | 89.4 |
| Depreciation & amortization | 57.4 | 53.6 |
| Taxes other than income taxes | 14.4 | 17.1 |
| Total operating expenses | 311.5 | 315.9 |
| OPERATING INCOME | 113.5 | 107.5 |
| Other income - net | 7.0 | 5.6 |
| Interest expense | 17.6 | 17.5 |
| INCOME BEFORE INCOME TAXES | 102.9 | 95.6 |
| Income taxes | 37.0 | 34.5 |
| NET INCOME | $65.9 | $61.1 |

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, | |
|---|---|---|
| | 2017 | 2016 |
| CASH FLOWS FROM OPERATING ACTIVITIES | | |
| Net income | $65.9 | $61.1 |
| Adjustments to reconcile net income to cash from operating activities: | | |
| Depreciation & amortization | 57.4 | 53.6 |
| Deferred income taxes & investment tax credits | 25.1 | 22.7 |
| Expense portion of pension & postretirement benefit cost | 0.9 | 1.0 |
| Provision for uncollectible accounts | 2.0 | 2.7 |
| Other non-cash items - net | (0.1 ) | 1.8 |
| Changes in working capital accounts: | | |
| Accounts receivable & accrued unbilled revenues | 41.0 | 27.3 |
| Inventories | 13.1 | 12.6 |
| Recoverable/refundable fuel & natural gas costs | 2.8 | (16.8 ) |
| Prepayments & other current assets | 16.6 | 18.0 |
| Accounts payable, including to Vectren companies & affiliated companies | (56.7 ) | (43.5 ) |
| Accrued liabilities | 26.4 | 26.9 |
| Cash to fund pension plans | — | (15.0 ) |
| Changes in noncurrent assets | (5.5 ) | (7.8 ) |
| Changes in noncurrent liabilities | (1.9 ) | 2.1 |
| Net cash provided by operating activities | 187.0 | 146.7 |
| CASH FLOWS FROM FINANCING ACTIVITIES | | |
| Proceeds from additional capital contribution | 41.5 | 26.5 |
| Requirements for dividends to parent | (30.5 ) | (29.0 ) |
| Net change in short-term borrowings | (93.0 ) | (14.5 ) |
| Net cash used in financing activities | (82.0 ) | (17.0 ) |
| CASH FLOWS FROM INVESTING ACTIVITIES | | |
| Requirements for: | | |
| Capital expenditures, excluding AFUDC equity | (108.5) | (88.4 ) |
| Changes in restricted cash | 0.9 | — |
| Net cash used in investing activities | (107.6) | (88.4 ) |
| Net change in cash & cash equivalents | (2.6 ) | 41.3 |
| Cash & cash equivalents at beginning of period | 9.4 | 6.2 |
| Cash & cash equivalents at end of period | $6.8 | $47.5 |

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 597,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 145,000 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 320,000 natural gas customers located near Dayton in west-central Ohio.

2. Basis of Presentation

The interim condensed consolidated financial statements included in this report have been prepared by the Company, without audit, as provided in the rules and regulations of the Securities and Exchange Commission and include a review of subsequent events through the date the financial statements were issued. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been omitted as provided in such rules and regulations. The information in this report reflects all adjustments which are, in the opinion of management, necessary to fairly state the interim periods presented, inclusive of adjustments that are normal and recurring in nature. These interim condensed consolidated financial statements and related notes should be read in conjunction with the Company's audited annual consolidated financial statements for the year ended December 31, 2016, filed with the Securities and Exchange Commission on March 9, 2017, on Form 10-K. Because of the seasonal nature of the Company's utility operations, the results shown on a quarterly basis are not necessarily indicative of annual results.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates.

3. Subsidiary Guarantor and Consolidating Information

The Company's three operating utility companies, SIGECO, Indiana Gas, and VEDO, are guarantors of the Company's $350 million in short-term credit facilities, of which $101 million was outstanding at March 31, 2017, and the

Company's $996 million in unsecured senior notes outstanding at March 31, 2017. 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, 2017 (in millions):

| ASSETS | Subsidiary Guarantors | Parent Company | Eliminations & Reclassifications | Consolidated |
|---|---|---|---|---|
| Current Assets | | | | |
| Cash & cash equivalents | $ 6.5 | $ 0.3 | $ — | $ 6.8 |
| Accounts receivable - less reserves | 95.5 | 0.2 | — | 95.7 |
| Intercompany receivables | 30.9 | 110.0 | (140.9) | — |
| Accrued unbilled revenues | 75.9 | — | — | 75.9 |
| Inventories | 105.9 | — | — | 105.9 |
| Recoverable fuel & natural gas costs | 27.1 | — | — | 27.1 |
| Prepayments & other current assets | 17.5 | 6.2 | (2.8) | 20.9 |
| Total current assets | 359.3 | 116.7 | (143.7) | 332.3 |
| Utility Plant | | | | |
| Original cost | 6,633.5 | 0.4 | — | 6,633.9 |
| Less: accumulated depreciation & amortization | 2,609.0 | — | — | 2,609.0 |
| Net utility plant | 4,024.5 | 0.4 | — | 4,024.9 |
| Investments in consolidated subsidiaries | — | 1,621.9 | (1,621.9) | — |
| Notes receivable from consolidated subsidiaries | — | 945.4 | (945.4) | — |
| Investments in unconsolidated affiliates | 0.2 | — | — | 0.2 |
| Other investments | 22.1 | 0.4 | — | 22.5 |
| Nonutility plant - net | 1.7 | 163.5 | — | 165.2 |
| Goodwill - net | 205.0 | — | — | 205.0 |
| Regulatory assets | 206.2 | 16.0 | — | 222.2 |
| Other assets | 53.1 | 4.0 | (8.9) | 48.2 |
| TOTAL ASSETS | $ 4,872.1 | $ 2,868.3 | $ (2,719.9) | $ 5,020.5 |

| LIABILITIES & SHAREHOLDER'S EQUITY | Subsidiary Guarantors | Parent Company | Eliminations & Reclassifications | Consolidated |
|---|---|---|---|---|
| Current Liabilities | | | | |
| Accounts payable | $ 134.8 | $ 5.5 | $ — | $ 140.3 |
| Intercompany payables | 18.9 | — | (18.9) | — |
| Payables to other Vectren companies | 22.7 | — | — | 22.7 |
| Accrued liabilities | 149.1 | 20.2 | (2.8) | 166.5 |
| Short-term borrowings | — | 101.4 | — | 101.4 |
| Intercompany short-term borrowings | 91.1 | 30.9 | (122.0) | — |
| Current maturities of long-term debt | 49.1 | — | — | 49.1 |
| Total current liabilities | 465.7 | 158.0 | (143.7) | 480.0 |
| Long-Term Debt | | | | |
| Long-term debt | 335.4 | 995.8 | — | 1,331.2 |
| Long-term debt due to VUHI | 945.4 | — | (945.4) | — |
| Total long-term debt - net | 1,280.8 | 995.8 | (945.4) | 1,331.2 |
| Deferred Credits & Other Liabilities | | | | |
| Deferred income taxes | 878.7 | 3.2 | — | 881.9 |
| Regulatory liabilities | 460.8 | 1.2 | — | 462.0 |
| Deferred credits & other liabilities | 164.2 | 9.2 | (8.9) | 164.5 |
| Total deferred credits & other liabilities | 1,503.7 | 13.6 | (8.9) | 1,508.4 |
| Common Shareholder's Equity | | | | |

| | | | | |
|---|---|---|---|---|
| Common stock (no par value) | 845.9 | 872.7 | (845.9 ) | 872.7 |
| Retained earnings | 776.0 | 828.2 | (776.0 ) | 828.2 |
| Total common shareholder's equity | 1,621.9 | 1,700.9 | (1,621.9 ) | 1,700.9 |
| TOTAL LIABILITIES & SHAREHOLDER'S EQUITY | $ 4,872.1 | $ 2,868.3 | $ (2,719.9 ) | $ 5,020.5 |

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Condensed Consolidating Balance Sheet as of December 31, 2016 (in millions):

| ASSETS | Subsidiary Guarantors | Parent Company | Eliminations & Reclassifications | Consolidated |
|---|---|---|---|---|
| Current Assets | | | | |
| Cash & cash equivalents | $ 7.6 | $ 1.8 | $ — | $ 9.4 |
| Accounts receivable - less reserves | 102.4 | 0.2 | — | 102.6 |
| Intercompany receivables | 17.5 | 157.1 | (174.6) | — |
| Accrued unbilled revenues | 112.0 | — | — | 112.0 |
| Inventories | 119.0 | — | — | 119.0 |
| Recoverable fuel & natural gas costs | 29.9 | — | — | 29.9 |
| Prepayments & other current assets | 36.5 | 4.4 | (2.3) | 38.6 |
| Total current assets | 424.9 | 163.5 | (176.9) | 411.5 |
| Utility Plant | | | | |
| Original cost | 6,545.4 | — | — | 6,545.4 |
| Less: accumulated depreciation & amortization | 2,562.5 | — | — | 2,562.5 |
| Net utility plant | 3,982.9 | — | — | 3,982.9 |
| Investments in consolidated subsidiaries | — | 1,577.2 | (1,577.2) | — |
| Notes receivable from consolidated subsidiaries | — | 945.4 | (945.4) | — |
| Investments in unconsolidated affiliates | 0.2 | — | — | 0.2 |
| Other investments | 20.9 | 0.4 | — | 21.3 |
| Nonutility plant - net | 1.7 | 163.1 | — | 164.8 |
| Goodwill - net | 205.0 | — | — | 205.0 |
| Regulatory assets | 190.0 | 16.2 | — | 206.2 |
| Other assets | 53.9 | 3.7 | (8.6) | 49.0 |
| TOTAL ASSETS | $ 4,879.5 | $ 2,869.5 | $ (2,708.1) | $ 5,040.9 |

| LIABILITIES & SHAREHOLDER'S EQUITY | Subsidiary Guarantors | Parent Company | Eliminations & Reclassifications | Consolidated |
|---|---|---|---|---|
| Current Liabilities | | | | |
| Accounts payable | $ 194.6 | $ 10.8 | $ — | $ 205.4 |
| Intercompany payables | 14.8 | — | (14.8) | — |
| Payables to other Vectren companies | 25.4 | — | — | 25.4 |
| Accrued liabilities | 126.0 | 16.4 | (2.3) | 140.1 |
| Short-term borrowings | — | 194.4 | — | 194.4 |
| Intercompany short-term borrowings | 142.3 | 17.5 | (159.8) | — |
| Current maturities of long-term debt | 49.1 | — | — | 49.1 |
| Total current liabilities | 552.2 | 239.1 | (176.9) | 614.4 |
| Long-Term Debt | | | | |
| Long-term debt - net of current maturities & debt subject to tender | 335.2 | 995.8 | — | 1,331.0 |
| Long-term debt due to VUHI | 945.4 | — | (945.4) | — |
| Total long-term debt - net | 1,280.6 | 995.8 | (945.4) | 1,331.0 |
| Deferred Credits & Other Liabilities | | | | |
| Deferred income taxes | 855.4 | (0.9) | — | 854.5 |
| Regulatory liabilities | 452.4 | 1.3 | — | 453.7 |
| Deferred credits & other liabilities | 161.7 | 10.2 | (8.6) | 163.3 |
| Total deferred credits & other liabilities | 1,469.5 | 10.6 | (8.6) | 1,471.5 |

| | | | | |
|---|---|---|---|---|
| Common Shareholder's Equity | | | | |
| Common stock (no par value) | 844.4 | 831.2 | (844.4 ) | 831.2 |
| Retained earnings | 732.8 | 792.8 | (732.8 ) | 792.8 |
| Total common shareholder's equity | 1,577.2 | 1,624.0 | (1,577.2 ) | 1,624.0 |
| TOTAL LIABILITIES & SHAREHOLDER'S EQUITY | $ 4,879.5 | $ 2,869.5 | $ (2,708.1 ) | $ 5,040.9 |

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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 |

Condensed Consolidating Statement of Income for the three months ended March 31, 2016 (in millions):

| | Subsidiary Guarantors | Parent Company | Eliminations & Reclassifications | Consolidated |
|---|---|---|---|---|
| OPERATING REVENUES | | | | |
| Gas utility | $ 281.2 | $ — | $ — | $ 281.2 |
| Electric utility | 142.1 | — | — | 142.1 |
| Other | — | 10.6 | (10.5) | 0.1 |
| Total operating revenues | 423.3 | 10.6 | (10.5) | 423.4 |
| OPERATING EXPENSES | | | | |
| Cost of gas sold | 111.6 | — | — | 111.6 |
| Cost of fuel & purchased power | 44.2 | — | — | 44.2 |
| Other operating | 99.4 | — | (10.0) | 89.4 |
| Depreciation & amortization | 47.6 | 6.0 | — | 53.6 |
| Taxes other than income taxes | 16.6 | 0.5 | — | 17.1 |
| Total operating expenses | 319.4 | 6.5 | (10.0) | 315.9 |
| OPERATING INCOME | 103.9 | 4.1 | (0.5) | 107.5 |
| Other income - net | 4.6 | 12.3 | (11.3) | 5.6 |
| Interest expense | 16.9 | 12.4 | (11.8) | 17.5 |
| INCOME BEFORE INCOME TAXES | 91.6 | 4.0 | — | 95.6 |
| Income taxes | 34.6 | (0.1) | — | 34.5 |
| Equity in earnings of consolidated companies, net of tax | — | 57.0 | (57.0) | — |

| | | | | |
|---|---|---|---|---|
| NET INCOME | $ 57.0 | $ 61.1 | $ (57.0 ) | $ 61.1 |

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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 |

Condensed Consolidating Statement of Cash Flows for the three months ended March 31, 2016 (in millions):

| | Subsidiary Guarantors | Parent Company | Eliminations | Consolidated |
|---|---|---|---|---|
| NET CASH PROVIDED BY OPERATING ACTIVITIES | $ 134.8 | $ 11.9 | $ — | $ 146.7 |
| CASH FLOWS FROM FINANCING ACTIVITIES | | | | |
| Proceeds from: | | | | |
| Long-term debt, net of issuance costs | 109.4 | — | (109.4) | — |
| Additional capital contribution from parent | 26.5 | 26.5 | (26.5) | 26.5 |
| Requirements for: | | | | |
| Dividends to parent | (27.2) | (29.0) | 27.2 | (29.0) |
| Net change in intercompany short-term borrowings | (126.8) | 26.7 | 100.1 | — |
| Net change in short-term borrowings | — | (14.5) | — | (14.5) |
| Net cash used in financing activities | (18.1) | 9.7 | (8.6) | (17.0) |
| CASH FLOWS FROM INVESTING ACTIVITIES | | | | |
| Proceeds from: | | | | |
| Consolidated subsidiary distributions | — | 27.2 | (27.2) | — |
| Requirements for: | | | | |
| Capital expenditures, excluding AFUDC equity | (81.7) | (6.7) | — | (88.4) |
| Consolidated subsidiary investments | — | (26.5) | 26.5 | — |
| Net change in long-term intercompany notes receivable | — | (109.4) | 109.4 | — |
| Net change in short-term intercompany notes receivable | (26.7) | 126.8 | (100.1) | — |

| | | | | |
|---|---|---|---|---|
| Net cash used in investing activities | (108.4 ) | 11.4 | 8.6 | (88.4 ) |
| Net change in cash & cash equivalents | 8.3 | 33.0 | — | 41.3 |
| Cash & cash equivalents at beginning of period | 5.5 | 0.7 | — | 6.2 |
| Cash & cash equivalents at end of period | $ 13.8 | $ 33.7 | $ — | $ 47.5 |

4. Excise and Utility Receipts Taxes

Excise taxes and a portion of utility receipts taxes are included in rates charged to customers. Accordingly, the Company records these taxes billed to customers, which totaled $9.4 million in each of the three months ended March 31, 2017 and 2016, 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.

5. Supplemental Cash Flow Information

As of March 31, 2017 and December 31, 2016, the Company had accruals related to utility and nonutility plant purchases totaling approximately $19.1 million and $27.4 million, respectively.

6. 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 $25.8 million and $19.6 million for the three months ended March 31, 2017 and 2016, respectively. Amounts owed to VISCO at March 31, 2017 and December 31, 2016 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, 2017 and 2016, the Company received corporate allocations totaling $16.9 million and $17.3 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.

7. 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.

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

8. Gas Rate & Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement

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

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, 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 that, among other things, requests for recovery include a seven-year project plan. Once the plan is approved by the IURC, 80 percent of such costs are eligible for current recovery using a periodic rate adjustment mechanism. Recoverable costs include a return on the investment that reflects the current capital structure and associated costs, with the exception of the rate of return on equity, which remains fixed at the rate determined in the Company's last rate case. Recoverable costs also include recovery of depreciation and other operating expenses. The remaining 20 percent of project costs are deferred and recovered in the utility’s next general rate case, which must be filed before the expiration of the seven-year plan. The adjustment mechanism is capped at an annual increase in retail revenues of no more than two percent.

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.

Indiana Recovery and Deferral Mechanisms

The Company's Indiana natural gas utilities received Orders in 2008 and 2007 associated with the most recent base rate cases. These Orders authorized the deferral of financial impacts associated with bare steel and cast iron replacement activities. The Orders provide for the deferral of depreciation and post-in-service carrying costs on qualifying projects totaling $20 million annually at Indiana Gas and $3 million annually at SIGECO. The debt-related post-in-service carrying costs are currently recognized in the Consolidated Statements of Income. The recording of post-in-service carrying costs and depreciation deferral is limited by individual qualifying project to three years after being placed into service at SIGECO and four years after being placed into service at Indiana Gas. At March 31, 2017 and December 31, 2016, the Company has regulatory assets totaling $22.3 million and $21.9 million, respectively, associated with the deferral of depreciation and debt-related post-in-service carrying cost activities. Beginning in 2014, all bare steel and cast iron replacement activities are now part of the Company’s seven-year capital investment plan discussed below.

Requests for Recovery under Indiana Regulatory Mechanisms

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.

In March 2016, the IURC issued an Order re-approving approximately $890 million of the Company’s gas infrastructure modernization projects requested in the third update of the Plan, and approving the inclusion in rates of actual investments made through June 30, 2015. While most of the proposed capital spend has been approved as proposed, approximately $80 million of projects were not approved for recovery through the mechanisms pursuant to these filings. Specifically, the Company proposed to add a new project to its Plan pursuant to Senate Bill 560 totaling approximately $65 million. The project, which consists of a 20-mile transmission line and other related investments required to support industrial customer growth and ongoing system reliability in the Lafayette, Indiana area, as well as allows the Company to further diversify its gas supply portfolio via access to shale gas in the Marcellus and Utica reserves, was excluded for recovery under the Plan. The IURC stated because the project was not in the original plan filed in 2013, it does not qualify for cost recovery under Senate Bill 560. In the Order, the IURC did pre-approve the project for rate base inclusion upon the filing of the next base rate case. The Company believes such plan updates should be expected to accommodate new projects that emerge during the term of the plan as ongoing risk assessments determine new projects are required. The Company filed an appeal of the March 2016 Order on April 29, 2016 to challenge the IURC's finding which limits the scope of the Plan updates. On April 27, 2017, the Indiana Court of Appeals denied the Company's appeal of the Order. The Company is evaluating its options related to the Plan update issue, but as noted herein the project at issue was previously approved by the IURC for recovery in the Company's next general base rate case. Further, the Company does not expect similar issues related to updating future plan filings as the project inclusion process is now better understood by all parties.

Subsequent to the March 2016 Order, the Company has received two additional Orders approving plan investments. On June 29, 2016, the IURC issued an Order approving the inclusion in rates of investments made from July 2015 to December 2015. On January 25, 2017 the IURC issued an Order (January 2017 Order) approving the inclusion in rates of investments made from January 2016 to June 2016. Through the January 2017 Order, approximately $338 million of the approved capital investment plan has been incurred and included for recovery. The January 2017 Order also approved the Company's plan update, which is now $950 million through 2020. The plan increase of $60 million is due to additional investment related to pipeline safety and compliance requirements under Senate Bill 251.

At March 31, 2017 and December 31, 2016, the Company has regulatory assets related to the Plan totaling $54.9 million and $51.1 million, respectively.

On April 3, 2017, the Company submitted its sixth semi-annual filing, seeking approval for recovery of an additional $69.1 million of capital investments made through December 31, 2016. An evidentiary hearing has been scheduled for June 22, 2017, and the Company expects an order later in 2017.

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 total, the Company has made capital investments on projects that are now in-service under the DRR totaling $269.7 million as of March 31, 2017, of which $204.0 million has been approved for recovery under the DRR through December 31, 2015. On May 1, 2017, the Company submitted its annual request for an adjustment in the DRR rates to recover an additional $57.1 million of capital investments made through December 31, 2016. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $25.9 million and $24.4 million at March 31, 2017 and December 31, 2016, 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. At March 31, 2017 and December 31, 2016, the

Company has regulatory assets totaling $46.7 million and $41.9 million, respectively, associated with the deferral of depreciation, post-in-service carrying costs, and property taxes. As of March 31, 2017, the Company's deferrals have not reached this bill impact cap. On May 1, 2017, 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.

Given the extension of the DRR through 2017, as discussed above, and the continued ability to defer other capital expenses under House Bill 95, it is anticipated that the Company will file a general rate case for the inclusion in rate base of the above costs in early 2018.

Pipeline and Hazardous Materials Safety Administration (PHMSA)
In March 2016, PHMSA published a notice of proposed rulemaking (NPRM) on the safety of gas transmission and gathering lines. The proposed rule addresses many of the remaining requirements of the 2011 Pipeline Safety Act, with a particular focus on extending integrity management rules to address a much larger portion of the natural gas infrastructure and adds requirements to address broader threats to the integrity of a pipeline system. The Company is evaluating the impact 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. It is expected the rule will be finalized in 2018 and the Company believes the costs to comply with the new rules would be considered federally mandated and therefore should be recoverable.

In December 2016, PHMSA issued 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. These rules could increase the potential for capital expenditures and increase operating and maintenance expenses. The Company believes the cost to comply with these new rules would be considered federally mandated and therefore should be recoverable using various regulatory recovery mechanisms.

Additionally, PHMSA finalized a rule on excess flow valves, which went into effect in April 2017. At the customer's request, excess flow valves will be installed at the customer's cost.

9. Electric Rate & Regulatory Matters

Regulatory Treatment of Investments in Electric Infrastructure
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. The filing requests the recovery of associated capital expenditures estimated to be approximately $500 million over the seven-year period beginning in 2017. A field hearing in this proceeding was held on May 2, 2017. Testimony from the public provided during this hearing will be considered by the IURC in this case. Filed testimony of intervening parties was required by May 4, 2017. An evidentiary hearing has been scheduled for June 26, 2017. Under the timeline provided by Senate Bill 560, the Company expects an order in September 2017.

Renewable Generation Resources
On February 22, 2017, the Company also filed for authority 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 Integrated Resource Plan (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. See more information on the IRP below in Environmental & Sustainability Matters. The cost of the projects is estimated to be approximately $15 million. Filed testimony of intervening parties was required by May 11, 2017. An evidentiary hearing has been scheduled for June 15, 2017, and the Company expects an order by the end of 2017.

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 March 31, 2017, $30 million has been spent on equipment to control mercury in both air and water emissions, and $40 million to address the issues raised in the NOV. The 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. These costs will be included for recovery no later than the next rate case. The initial phase of the projects went into service in 2014, with the remaining investment going into service in 2016. As of March 31, 2017, the Company has approximately $9.0 million deferred related to depreciation and operating expense, and $3.3 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.

In June 2015, Joint Appellants’ Citizens Action Coalition of Indiana, Inc., Sierra Club, Inc., and Valley Watch, Inc. (the appellants) challenged the IURC's January 2015 Order. On October 29, 2015, the Indiana Court of Appeals issued an opinion that affirmed the IURC’s findings with regard to equipment required to comply with MATS and certain national pollutant discharge elimination system rules but remanded the case to the IURC to determine whether a certificate of public convenience and necessity (CPCN) should be issued for the equipment required by the NOV. On June 22, 2016, the IURC issued an Order granting the Company a CPCN for the NOV-required equipment. On July 21, 2016, the appellants initiated an appeal of the IURC's June 22, 2016 Order challenging the findings made by the IURC. On February 14, 2017, the Court affirmed the IURC's June 22, 2016 Order.

SIGECO Electric Demand Side Management (DSM) Program Filing

On August 31, 2011, the IURC issued an Order approving an initial three-year DSM plan in the Company's electric service territory that complied with the IURC’s energy saving targets. Consistent with the Company’s proposal, the Order approved, among other items, the following: 1) recovery of costs associated with implementing the DSM Plan; 2) the recovery of a performance incentive mechanism based on measured savings related to certain DSM programs; and 3) lost margin recovery associated with the implementation of DSM programs for large customers. On June 20, 2012, the IURC issued an Order approving a small customer lost margin recovery mechanism, inclusive of all previous deferrals. For the three months ended March 31, 2017 and 2016, the Company recognized electric utility revenue of $3.0 million and $2.6 million, respectively, associated with this approved lost margin recovery mechanism.

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, most of the Company’s eligible industrial customers 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 provides for cost recovery of program and administrative expenses and includes performance incentives for reaching energy savings goals. The Order also included a lost margin recovery mechanism that now limits that recovery related to new programs to the shorter of four years or the life of the installed energy efficiency measure. Prior electric energy efficiency orders did not limit lost margin recovery in this manner. This ruling follows other recent 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 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 has been remanded back to the Commission for further proceedings to determine the reasonableness of the Company's entire energy efficiency plan.

On April 10, 2017, the Company submitted its request for approval 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 over the life of the installed energy efficiency measure. Filed testimony of intervening parties is required by July 14, 2017. An evidentiary hearing has been scheduled for August 31, 2017, and the Company expects an order by the end of 2017.

FERC Return on Equity (ROE) Complaints

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

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

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

The Company has reflected these results in its financial statements. As of March 31, 2017, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $136.0 million at March 31, 2017.

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 and also failed to provide any reasoned basis for their selected ROE. 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.

10. Environmental & Sustainability Matters

The Company initiated a corporate sustainability program in 2012 with the publication of the initial corporate sustainability report of the Company's parent. Since that time the Company continues to develop strategies that focus on those environmental, social and governance (ESG) factors that contribute to the long-term growth of a sustainable business model. As detailed further below and in the upcoming corporate sustainability report for 2016, the Company continues to set out its plans, among other things, to upgrade and diversify its generation portfolio. 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 Vectren's Corporate Responsibility and Sustainability Committee, as well as vetted with Vectren's full Board of Directors. Further discussion of key goals, strategies, and governance practices can be found in the Company’s latest sustainability report, which received core level certification from the Global Reporting Initiative.

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.

Integrated Resource Planning Process

As required by the state of Indiana, the Company completed its 2016 Integrated Resource Plan (IRP) and submitted to 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 provide comments on the plan. While the IURC does not approve or reject the IRP, comments received are taken into consideration, ultimately resulting in a report issued by the IURC, likely in the summer of 2017.

Currently, the Company operates approximately 1,000 MW of coal-fired generation, 245 MW of natural gas peaking units, and 3 MW via a landfill-gas-to-electricity facility. The Company also has 80 MW of wind power through two long-term power purchase agreements and 32 MW of coal generation through its ownership in OVEC. The Company’s 2016 IRP preferred portfolio illustrates a future less reliant on coal. The twenty year plan reflects the retirement of a portion of the Company’s current coal-fired fleet, transitions a significant portion of generation to natural gas and includes new renewable energy sources, specifically universal solar. The detailed plan would introduce approximately 54 MW of universal solar installed by 2019. The plan suggests the Company will exit its joint operations of Warrick Unit 4, a 300 MW unit shared with Alcoa, by 2020. The Company would complete upgrades to its existing coal-fired F.B. Culley Unit 3, a 270-megawatt unit, to comply with federal water regulations specific to the Effluent Limitations Guidelines (ELG) around 2023 in order to keep the unit in operation. As discussed in more detail in the ELG section below, the EPA has administratively stayed the compliance deadlines in the ELG rule pending reconsideration. In 2024, the IRP points to the retirement of coal-fired A.B. Brown plant Units 1 & 2 along with F.B. Culley Unit 2, collectively representing 580 MW. This generation would be replaced by a newly constructed combined cycle natural gas plant, with the capability of producing approximately 890 MW by 2024. In addition, the Company intends to continue to offer energy efficiency programs annually. Similarly, as discussed in more detail below, the short-term uncertainties related to ELG implementation are not expected to have a significant impact on the Company’s long term preferred generation 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. The Company plans to finalize this generation portfolio transition plan and submit a regulatory filing, including construction timelines and costs of new generation resources, as well as necessary unit retrofits, to the IURC in late 2017 to begin the generation transition process. The Company will seek approval of its generation plan, including timely recovery of all federally mandated compliance costs, as well as the authority to defer the cost of new generation until the time of a rate case.

Coal Ash Waste Disposal, Ash Ponds and Water

Coal Combustion Residuals Rule

In December 2014, the EPA released its final Coal Combustion Residuals (CCR) rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). On April 17, 2015, the final rule was published in the Federal Register. The final rule allows beneficial reuse of ash and the majority of the ash generated by the

Company's generating plants will continue to be reused. As it relates to the CCR rule, legislation was passed in December 2016 by Congress that would provide for enforcement of the federal program by states rather than through citizen suits. Additionally, the CCR rule is currently being challenged by multiple parties in judicial review proceedings.

Under the final CCR rule, the Company is required to complete a series of integrity assessments, including seismic modeling given the Company's facilities are located within two seismic zones, and groundwater monitoring studies to determine the remaining service life of the ponds and whether a pond must be retrofitted with liners or closed in place, with bottom ash handling conversions completed. In late 2015, using general utility industry data, the Company prepared cost estimates for the retirement of the ash ponds at the end of their useful lives, based on its interpretation of the closure alternatives contemplated in the final rule. The resulting estimates ranged from approximately $35 million to $80 million. These estimates contemplated final capping and monitoring costs of the ponds at both F.B. Culley and A.B. Brown generating stations. These rules 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.

Throughout 2016, the Company has continued to refine site specific estimates and now estimates the costs to be in the range of $45 million to $100 million. Significant factors impacting the resulting cost estimates include the closure time frame and the method of closure. Current estimates contemplate additional beneficial reuse of the ash, as well as implications of the Company's preferred IRP. Ongoing analysis, the continued refinement of assumptions, or the inability to beneficially reuse the ash may result in estimated costs in excess of the current range.

As of December 31, 2016, the Company had 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 has 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 (ELGs)
Under the Clean Water Act, the EPA sets technology-based guidelines for water discharges from new and existing electric generation facilities. On September 30, 2015, the EPA released final revisions to the existing steam electric ELGs setting stringent technology-based water discharge limits for the electric power industry. The EPA focused this rulemaking on wastewater generated primarily by pollution control equipment necessitated by the comprehensive air regulations, specifically setting strict water discharge limits for arsenic, mercury and selenium for scrubber waste waters. The ELGs will be implemented when existing water discharge permits for the plants are renewed, with compliance activities expected to commence where operations continue, within the 2018-2023 time frame. The ELGs work in tandem with the aforementioned CCR requirements, effectively prohibiting the use of less costly lined sediment basin options for disposal of coal combustion residuals, and virtually mandate conversions to dry bottom ash handling.

The current 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 state environmental agency in February 2017 and March 2017, respectively. As part of the permit renewals, the Company requested alternate compliance dates for ELGs. Compliance with the ELGs will not be required prior to November 2018, but no later than December 31, 2023. For plants identified in the Company's preferred 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 the state agency provided that the Company notifies the state within one year of issuance of the renewal of its intent to retire the unit. For the F.B. Culley plant, the Company has proposed a 2020 compliance date for dry bottom ash and 2023 compliance date for flue gas desulfurization wastewater, which was approved by the state and finalized in the permit renewal.

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. With publication in the federal register, the EPA will be seeking public comment on the stay of the ELG implementation deadlines. The EPA has also indicated it intends to seek a stay of the current judicial review litigation in federal district court. As the Company does not currently have short-term ELG implementation deadlines in its recently renewed wastewater discharge permits, the Company does not currently anticipate immediate impacts from the EPA's administrative stay of implementation deadlines due to the longer compliance time frames granted by the state, and will continue to work with the state agency to evaluate further implementation plans. The Company believes the stay of the ELG implementation deadlines do not impact its preferred generation plan as modeled in the IRP due to comparable ash handling restrictions required by the CCR rule which is not subject to an administrative stay, and other projected operational expenditures; however, on May 3, 2017, a coalition of environmental organizations filed a challenge to the stay of the ELG rule in the U.S. District Court for the District of Columbia.

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 a state level case-by-case assessment of BTA for each facility. The final rule lists seven presumptive technologies which would qualify as BTA. These technologies range from intake screen modifications to cooling water tower retrofits. Ecological and technology assessment studies must be completed prior to determining BTA for the Company's facilities. The Company is currently undertaking the required ecological studies and anticipates timely compliance in 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 that 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. The EPA was expected to make final determinations as to whether a region is in attainment for the new NAAQS in 2017; however, in a March filing challenging the new standard, the EPA filed a request to stay the litigation pending a potential review of the ozone standard by the agency. While the future of the current ozone standard is not certain, it is possible counties in southwest Indiana could be declared in non-attainment with the current ozone standard, and thus could have an effect on future economic development activities in the Company's service territory. The Company does not anticipate any significant compliance cost impacts from the determination given its previous investment in SCR technology for NOx control on its units. In September 2016, the EPA finalized a supplement to the Cross State Air Pollution Rule (CSAPR) that requires further NOx reductions during the ozone season (May - September). The Company is positioned to comply with these NOx reduction requirements through its current investment in SCR technology.

One Hour SO2 NAAQS
On February 16, 2016, the EPA notified states of the commencement of a 120 day consultation period between the state and the EPA with respect to the EPA's recommendations for new non-attainment designations for the 2010 One Hour SO2 NAAQS. Identified on the list was Posey County, Indiana, where the Company's A.B. Brown Generating Station is located. While the Company is in compliance with all applicable SO2 limits in its permits, the Company reached an agreement with the state of Indiana on voluntary measures that the Company was able to implement

without significant incremental costs to ensure that Posey County remains in attainment with the 2010 One Hour SO2 NAAQS. The Company's coal-fired generating fleet is 100 percent scrubbed for SO2 and 90 percent controlled for NOx.

Climate Change

On August 3, 2015, the EPA released its final CPP rule which requires a 32 percent reduction in carbon emissions from 2005 levels. This results in a final emission rate goal for Indiana of 1,242 lb $CO_2$/MWh to be achieved by 2030. The new rule gives states the option of seeking a two-year extension from the initial deadline of September 2016 to submit a final state implementation plan (SIP). In March 2017, the EPA withdrew a Federal Implementation Plan (FIP) as a compliance option. Under the CPP, states have the flexibility to include energy efficiency and other measures should they choose to implement a SIP as provided in the final rule. While states are given an interim goal (1,451 lb $CO_2$/MWh for Indiana), the final rule gives states the flexibility to shape their own emissions reduction over the 2022-2029 time period. The final rule was published in the Federal Register on October 23, 2015, and that action was immediately followed by litigation initiated by Indiana and 23 other states as a coalition challenging the rule. In January 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. Extensive oral argument was held in September 2016. The stay will remain in place while the lower court concludes its review. Among other things, the stay delays the requirement to submit a final SIP by the original September 2016 deadline and could extend implementation to 2024. In March 2017, as part of the ongoing regulatory reform efforts of the Administration, the EPA has 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.

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

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

least cost to its customers.

In addition to the federal programs, the United States and 194 other countries agreed by consensus to limit GHG emissions beginning after 2020 in the 2015 United Nations Framework Convention on Climate Change Paris Agreement. The United States has proposed a 26-28 percent GHG emission reduction from 2005 levels by 2025. The Administration has not indicated yet whether it intends to remain in the Agreement or withdraw its participation. As previously noted, since 2005 through 2015, the Company has achieved reduced emissions of $CO_2$ by 31 percent (on a tonnage basis). While the litigation and 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 $15.4 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, 2017 and December 31, 2016, approximately $2.9 million of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

11. Fair Value Measurements

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

| | March 31, 2017 | | December 31, 2016 | |
|---|---|---|---|---|
| (In millions) | Carrying Amount | Est. Fair Value | Carrying Amount | Est. Fair Value |
| Long-term debt | $1,380.3 | $1,487.7 | $1,380.1 | $1,495.3 |
| Short-term borrowings | 101.4 | 101.4 | 194.4 | 194.4 |
| Cash & cash equivalents | 6.8 | 6.8 | 9.4 | 9.4 |
| Restricted Cash | — | — | 0.9 | 0.9 |

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

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

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

12. Impact of Recently Issued Accounting Principles

Revenue Recognition Guidance

In May 2014, the FASB issued new accounting guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for GAAP. The amendments in this guidance state that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This new guidance requires improved disclosures to help users of financial statements better understand the nature, amount, timing, and uncertainty of revenue that is recognized. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). While the Company continues to assess the standard and initial conclusions could change based on completion of that assessment, the Company preliminarily plans to adopt the guidance under the modified retrospective method.

In July 2015, the FASB approved a one year deferral that became effective through an ASU in August and changed the effective date to annual reporting periods beginning after December 15, 2017, including interim periods, with early adoption permitted, but not before the original effective date of December 15, 2016.

The Company is currently assessing the impacts this guidance may have on the Consolidated Balance Sheets, Consolidated Statements of Operations, and disclosures including the ability to recognize revenue for certain contracts, and its accounting for contributions in aid of construction (CIAC). While management will continue to analyze the impact of this new standard and the related ASUs that clarify guidance in the standard, at this time, management does not believe adoption of the standard will have a significant impact on the Company's pattern of revenue recognition. The Company plans to adopt the guidance effective January 1, 2018.

Leases

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

Stock Compensation

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

Presentation of Net Periodic Pension and Postretirement Benefit Costs

In March 2017, the FASB issued new accounting guidance to improve the presentation of net periodic pension and postretirement benefit costs. This ASU is effective for annual periods beginning after December 15, 2017, and relevant interim periods. Early adoption is permitted. This ASU requires that the service cost component is reported in the same line items as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit cost are required to be presented in the income statement separately from the service cost component and outside of income from operations. The Company does not have pension and postretirement plans separate from the Company's parent. However, the Company's parent allocates the periodic cost of its retirement plans to the Company's subsidiaries. The Company is currently evaluating the standard to determine the impact it will have on the financial statements, however, does not anticipate its adoption to have a significant impact on the financial statements. The Company plans to adopt the guidance effective January 1, 2018.

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

13. Segment Reporting

The Company’s operations consist of regulated operations and other operations that provide information technology and other support services to those regulated operations. The Company segregates its regulated operations between a Gas Utility Services operating segment and an Electric Utility Services operating segment. The Gas Utility Services segment provides natural gas distribution and transportation services to nearly two-thirds of Indiana and 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) | 2017 | 2016 |
| Revenues | | |
| Gas Utility Services | $292.8 | $281.2 |
| Electric Utility Services | 132.1 | 142.1 |
| Other Operations | 11.4 | 10.6 |
| Eliminations | (11.3 ) | (10.5 ) |
| Total Revenues | $425.0 | $423.4 |
| Profitability Measure - Net Income (Loss) | | |
| Gas Utility Services | $47.9 | |