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

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): August 14, 2018

CENTERPOINT ENERGY, INC.
(Exact name of registrant as specified in its charter)

Texas	1-31447	74-0694415
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

1111 Louisiana Houston, Texas	77002
(Address of principal executive offices)	(Zip Code)

Registrant’s telephone number, including area code: (713) 207-1111

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (*see* General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2).

Emerging Growth Company ☐

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 provided pursuant to Section 13(a) of the Exchange Act. ☐

Item 8.01 Other Events.

On April 21, 2018, CenterPoint Energy, Inc. (the "Company") entered into an Agreement and Plan of Merger (the "Merger Agreement"), by and among the Company, Vectren Corporation, an Indiana corporation ("Vectren"), and Pacer Merger Sub, Inc., an Indiana corporation and wholly owned subsidiary of the Company ("Merger Sub"). Pursuant to the Merger Agreement, on and subject to the terms and conditions set forth therein, Merger Sub will merge with and into Vectren (the "Merger"), with Vectren continuing as the surviving corporation in the Merger and becoming a wholly owned subsidiary of the Company. The Company expects to complete the Merger in the first quarter of 2019.

This Current Report on Form 8-K is being filed to provide consolidated financial statements of Vectren and pro forma condensed combined financial information relating to the Merger, each of which are incorporated herein by reference.

Item 9.01. Financial Statements and Exhibits.

(a) *Financial Statements of Businesses Acquired.*

The audited consolidated financial statements and related financial statement schedule of Vectren as of December 31, 2017 and 2016, and for the years ended December 31, 2017, 2016 and 2015, and the related Report of Independent Registered Public Accounting Firm, included in Vectren's Annual Report on Form 10-K for the fiscal year ended December 31, 2017, filed with the Securities and Exchange Commission on February 21, 2018, are attached hereto as Exhibit 99.1.

The unaudited consolidated financial statements of Vectren as of June 30, 2018 and 2017, and for the three-month and six-month periods ended June 30, 2018 and 2017 included in Vectren's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018, filed with the Securities and Exchange Commission on August 2, 2018, are attached hereto as Exhibit 99.2.

(b) Pro Forma Financial Information.

The unaudited pro forma condensed combined financial information relating to the Merger is attached hereto as Exhibit 99.3.

The exhibits listed below are filed herewith.

(d) Exhibits.

EXHIBIT NUMBER	EXHIBIT DESCRIPTION
12.1	Computation of Ratios of Earnings to Fixed Charges and Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends.
23.1	Consent of Deloitte & Touche LLP.
99.1	Audited consolidated financial statements and related financial statement schedule of Vectren Corporation as of December 31, 2017 and 2016, and for the years ended December 31, 2017, 2016 and 2015 and the related Report of Independent Registered Public Accounting Firm.
99.2	Unaudited condensed consolidated financial statements of Vectren Corporation as of June 30, 2018 and 2017, and for the three-month and six-month periods ended June 30, 2018 and 2017.
99.3	Unaudited pro forma condensed combined financial information relating to the Merger.

SIGNATURE

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 hereunto duly authorized.

CENTERPOINT ENERGY, INC.

Date: August 14, 2018

By: /s/ Kristie L. Colvin
Kristie L. Colvin
Senior Vice President and Chief Accounting Officer

Exhibit 12.1

RATIOS OF EARNINGS TO FIXED CHARGES AND RATIOS OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS

The following table sets forth our historical ratio of earnings to fixed charges for the periods indicated. The ratios are calculated pursuant to the applicable rules of the SEC.

	Six Months Ended June 30,	Year Ended December 31,				
	2018(1)	2017	2016	2015	2014(2)	2013(2)
Ratio of earnings to fixed charges	1.69	3.70	2.74	2.67	2.79	2.42
Ratio of earnings to combined fixed charges and preferred stock dividends(3)	1.69	3.70	2.74	2.67	2.79	2.42

(1) We do not believe that the ratio for the six-month period is necessarily indicative of the ratio for the twelve-month period due to the seasonal nature of our business.

(2) Excluded from the computation of fixed charges for the years ended December 31, 2014, and 2013 is interest expense of $3 million and interest income of $6 million respectively, which is included in income tax expense.

(3) We had no preferred stock outstanding for any period presented above and, accordingly, our ratios of earnings to combined fixed charges and preferred stock dividends are the same as our ratios of earnings to fixed charges.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-215833 on Form S-3 of our report dated February 21, 2018, relating to the consolidated financial statements and financial statement schedule of Vectren Corporation and subsidiary companies appearing in the Current Report on Form 8-K of CenterPoint Energy, Inc. dated August 14, 2018.

/s/ DELOITTE & TOUCHE LLP
Indianapolis, Indiana

August 14, 2018

Exhibit 99.1

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Vectren Corporation:

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Vectren Corporation and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of income, comprehensive income, common shareholders' equity and cash flows for each of the three years in the period ended December 31, 2017, and the related notes and the schedule listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP
Indianapolis, Indiana
February 21, 2018

We have served as the Company's auditor since 2002.

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(In millions)

	At December 31, 2017	At December 31, 2016
ASSETS		
Current Assets		
Cash & cash equivalents	$ 16.6	$ 68.6
Accounts receivable - less reserves of $5.1 & $6.0, respectively	262.9	225.3
Accrued unbilled revenues	207.1	172.4
Inventories	126.6	129.9
Recoverable fuel & natural gas costs	19.2	29.9
Prepayments & other current assets	47.0	52.7
Total current assets	**679.4**	**678.8**
Utility Plant		
Original cost	7,015.4	6,545.4
Less: accumulated depreciation & amortization	2,738.7	2,562.5
Net utility plant	**4,276.7**	**3,982.9**
Investments in unconsolidated affiliates	19.7	20.4
Other utility & corporate investments	43.7	34.1
Other nonutility investments	9.6	16.1
Nonutility plant - net	464.1	423.9
Goodwill	293.5	293.5
Regulatory assets	416.8	308.8
Other assets	35.8	42.2
TOTAL ASSETS	**$6,239.3**	**$5,800.7**

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

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(In millions)

	At December 31, 2017	2016
LIABILITIES & SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 366.2	$ 302.2
Accrued liabilities	222.3	207.7
Short-term borrowings	249.5	194.4
Current maturities of long-term debt	100.0	124.1
Total current liabilities	**938.0**	**828.4**
Long-term Debt - Net of Current Maturities	1,738.7	1,589.9
Deferred Credits & Other Liabilities		
Deferred income taxes	491.3	905.7
Regulatory liabilities	937.2	453.7
Deferred credits & other liabilities	284.8	254.9
Total deferred credits & other liabilities	**1,713.3**	**1,614.3**
Commitments & Contingencies (Notes 7, 17-20)		
Common Shareholders' Equity		
Common stock (no par value) - issued & outstanding 83.0 & 82.9 shares, respectively	736.9	729.8
Retained earnings	1,113.7	1,039.6
Accumulated other comprehensive (loss)	(1.3)	(1.3)
Total common shareholders' equity	**1,849.3**	**1,768.1**
TOTAL LIABILITIES & SHAREHOLDERS' EQUITY	**$6,239.3**	**$5,800.7**

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

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
(In millions, except per share amounts)

	Year Ended December 31,		
	2017	2016	2015
OPERATING REVENUES			
Gas utility	$ 812.7	$ 771.7	$ 792.6
Electric utility	569.6	605.8	601.6
Nonutility	1,275.0	1,070.8	1,040.5
Total operating revenues	**2,657.3**	**2,448.3**	**2,434.7**
OPERATING EXPENSES			
Cost of gas sold	271.5	266.7	305.4
Cost of fuel & purchased power	171.8	183.6	187.5
Cost of nonutility revenues	444.2	363.4	355.0
Other operating	1,115.9	932.2	909.2
Depreciation & amortization	276.2	260.0	256.3
Taxes other than income taxes	59.3	60.9	59.5
Total operating expenses	**2,338.9**	**2,066.8**	**2,072.9**
OPERATING INCOME	**318.4**	**381.5**	**361.8**
OTHER INCOME			
Equity in earnings (losses) of unconsolidated affiliates	(1.1)	(0.2)	(0.6)
Other income – net	32.8	28.7	20.3
Total other income	31.7	28.5	19.7
Interest expense	87.7	85.5	84.5
INCOME BEFORE INCOME TAXES	**262.4**	**324.5**	**297.0**
Income taxes	46.4	112.9	99.7
NET INCOME	**$ 216.0**	**$ 211.6**	**$ 197.3**
WEIGHTED AVERAGE AND DILUTED COMMON SHARES OUTSTANDING	**83.0**	**82.8**	**82.7**
BASIC AND DILUTED EARNINGS PER SHARE OF COMMON STOCK	**$ 2.60**	**$ 2.55**	**$ 2.39**

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

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Year Ended December 31,		
	2017	2016	2015
NET INCOME	**$216.0**	**$211.6**	**$197.3**
Pension & other benefits			
Amounts arising during the year	(5.6)	(10.1)	1.2
Reclassifications to periodic cost	5.4	4.7	6.9
Deferrals to regulatory assets	0.2	5.3	(8.0)
Pension & other benefits costs, net of tax	**—**	**(0.1)**	**0.1**
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX	**—**	**(0.1)**	**0.1**
TOTAL COMPREHENSIVE INCOME	**$216.0**	**$211.5**	**$197.4**

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

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2017	2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 216.0	$ 211.6	$ 197.3
Adjustments to reconcile net income to cash from operating activities:			
Depreciation & amortization	276.2	260.0	256.3
Deferred income taxes & investment tax credits	19.0	100.1	80.4
Provision for uncollectible accounts	5.9	6.9	8.1
Expense portion of pension & postretirement benefit cost	5.4	3.6	6.8
Other non-cash items - net	12.9	7.8	7.3
Changes in working capital accounts:			
Accounts receivable & accrued unbilled revenues	(80.9)	(39.6)	(15.4)
Inventories	3.3	3.9	(15.2)
Recoverable/refundable fuel & natural gas costs	10.7	(37.8)	15.2
Prepayments & other current assets	5.7	22.9	20.3
Accounts payable, including to affiliated companies	65.9	40.7	(0.5)
Accrued liabilities	15.6	22.7	(0.9)
Employer contributions to pension & postretirement plans	(4.6)	(19.6)	(26.5)
Changes in noncurrent assets	(40.6)	(44.0)	(21.9)
Changes in noncurrent liabilities	(11.7)	(15.1)	(6.1)
Net cash from operating activities	**498.8**	**524.1**	**505.2**
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from:			
Long-term debt, net of issuance costs	198.5	—	385.5
Dividend reinvestment plan & other common stock issuances	6.3	6.3	6.2
Requirements for:			
Dividends on common stock	(141.9)	(134.2)	(127.3)
Retirement of long-term debt	(75.0)	(73.0)	(170.0)
Other financing activities	—	—	0.2
Net change in short-term borrowings	55.1	179.9	(141.9)
Net cash from financing activities	**43.0**	**(21.0)**	**(47.3)**
CASH FLOWS FROM INVESTING ACTIVITIES			
Proceeds from sale of assets and other collections	11.3	33.0	27.5
Requirements for:			
Capital expenditures, excluding AFUDC equity	(602.6)	(542.0)	(476.9)
Other costs	(3.4)	(5.2)	(14.3)
Changes in restricted cash	0.9	5.0	(5.9)
Net cash from investing activities	**(593.8)**	**(509.2)**	**(469.6)**
Net change in cash & cash equivalents	(52.0)	(6.1)	(11.7)
Cash & cash equivalents at beginning of period	68.6	74.7	86.4
Cash & cash equivalents at end of period	$ 16.6	$ 68.6	$ 74.7

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

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY
(In millions, except per share amounts)

	Common Stock		Retained	Accumulated Other Comprehensive	
	Shares	Amount	Earnings	Income (Loss)	Total
Balance at January 1, 2015	**82.6**	**$715.7**	**$ 892.2**	**$ (1.3)**	**$1,606.6**
Net income			197.3		197.3
Other comprehensive income (loss)				0.1	0.1
Common stock:					
Issuance: option exercises & dividend reinvestment plan	0.2	6.2			6.2
Dividends ($1.540 per share)			(127.3)		(127.3)
Other		0.9			0.9
Balance at December 31, 2015	**82.8**	**722.8**	**962.2**	**(1.2)**	**1,683.8**
Net income			211.6		211.6
Other comprehensive income (loss)				(0.1)	(0.1)
Common stock:					
Issuance: option exercises & dividend reinvestment plan	0.1	6.3			6.3
Dividends ($1.620 per share)			(134.2)		(134.2)
Other		0.7			0.7
Balance at December 31, 2016	**82.9**	**729.8**	**1,039.6**	**(1.3)**	**1,768.1**
Net income			216.0		216.0
Other comprehensive income (loss)					—
Common stock:					
Issuance: dividend reinvestment plan	0.1	6.3			6.3
Dividends ($1.710 per share)			(141.9)		(141.9)
Other		0.8			0.8
Balance at December 31, 2017	**83.0**	**$736.9**	**$1,113.7**	**$ (1.3)**	**$1,849.3**

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

1. Organization and Nature of Operations

Vectren Corporation (the Company or Vectren), an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana. The Company's wholly owned subsidiary, Vectren Utility Holdings, Inc. (Utility Holdings or VUHI), serves as the intermediate holding company for three public utilities: Indiana Gas Company, Inc. (Indiana Gas or Vectren Energy Delivery of Indiana - North), Southern Indiana Gas and Electric Company (SIGECO or Vectren Energy Delivery of Indiana - South), and Vectren Energy Delivery of Ohio, Inc. (VEDO). Utility Holdings also has other assets that provide information technology and other services to the three utilities. Utility Holdings' consolidated operations are collectively referred to as the Utility Group. Both Vectren and Utility Holdings are holding companies as defined by the Energy Policy Act of 2005. Vectren was incorporated under the laws of Indiana on June 10, 1999.

Indiana Gas provides energy delivery services to approximately 592,400 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 145,200 electric customers and approximately 111,500 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 318,100 natural gas customers located near Dayton in west-central Ohio.

The Company, through Vectren Enterprises, Inc. (Enterprises), is involved in nonutility activities in two primary business areas: Infrastructure Services and Energy Services. Infrastructure Services provides underground pipeline construction and repair services. Energy Services provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects. Enterprises also has other legacy businesses that have investments in energy-related opportunities and services and other investments. All of the above is collectively referred to as the Nonutility Group. Enterprises supports the Company's regulated utilities by providing infrastructure services.

2. Summary of Significant Accounting Policies

In applying its accounting policies, the Company makes judgments, assumptions, and estimates that affect the amounts reported in these consolidated financial statements and related footnotes. Examples of transactions for which estimation techniques are used include valuing pension and postretirement benefit obligations, deferred tax obligations, unbilled revenue, uncollectible accounts, regulatory assets and liabilities, asset retirement obligations, and derivatives and other financial instruments. Estimates also impact the depreciation of utility and nonutility plant and the testing of goodwill and other assets for impairment. Recorded estimates are revised when better information becomes available or when actual amounts can be determined. Actual results could differ from current estimates.

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries, after appropriate elimination of intercompany transactions. The Infrastructure Services segment, through wholly owned subsidiaries Miller Pipeline, LLC and Minnesota Limited, LLC, provides underground pipeline construction and repair services for customers that include Vectren Utility Holdings' utilities. In accordance with consolidation guidance under ASC 980, fees incurred by Vectren Utility Holdings and its subsidiaries for these pipeline construction and repair services, are appropriately not eliminated in consolidation.

Subsequent Events Review

Management performs a review of subsequent events for any events occurring after the balance sheet date but prior to the date the financial statements are issued.

Cash & Cash Equivalents

Highly liquid investments with an original maturity of three months or less at the date of purchase are considered cash equivalents. Cash and cash equivalents are stated at cost plus accrued interest to approximate fair value.

Allowance for Uncollectible Accounts

The Company maintains allowances for uncollectible accounts for estimated losses resulting from the inability of its customers to make required payments. The Company estimates the allowance for uncollectible accounts based on a variety of factors including the length of time receivables are past due, the financial health of its customers, unusual macroeconomic conditions, and historical experience. If the financial condition of its customers deteriorates or other circumstances occur that result in an impairment of customers' ability to make payments, the Company records additional allowances as needed.

Inventories

In most circumstances, the Company's inventory components are recorded using an average cost method; however, natural gas in storage at the Company's Indiana utilities are recorded using the Last In – First Out (LIFO) method. Inventory related to the Company's regulated operations is valued at historical cost consistent with ratemaking treatment. Materials and supplies are recorded as inventory when purchased and subsequently charged to expense or capitalized to plant when installed.

Property, Plant & Equipment

Both the Company's *Utility Plant* and *Nonutility Plant* is stated at historical cost, inclusive of financing costs and direct and indirect construction costs, less accumulated depreciation and when necessary, impairment charges. The cost of renewals and betterments that extend the useful life are capitalized. Maintenance and repairs, including the cost of removal of minor items of property and planned major maintenance projects, are charged to expense as incurred.

Utility Plant & Related Depreciation

Both the IURC and PUCO allow the Company's utilities to capitalize financing costs associated with *Utility Plant* based on a computed interest cost and a designated cost of equity funds. These financing costs are commonly referred to as AFUDC and are capitalized for ratemaking purposes and for financial reporting purposes instead of amounts that would otherwise be capitalized when acquiring nonutility plant. The Company reports both the debt and equity components of AFUDC in *Other – net* in the *Consolidated Statements of Income*.

When property that represents a retirement unit is replaced or removed, the remaining historical value of such property is charged to *Utility Plant*, with an offsetting charge to *Accumulated depreciation*, resulting in no gain or loss. Costs to dismantle and remove retired property are recovered through the depreciation rates as determined by the IURC and PUCO.

The Company's portion of jointly owned *Utility Plant*, along with that plant's related operating expenses, is presented in these financial statements in proportion to the ownership percentage.

Nonutility Plant & Related Depreciation

The depreciation of *Nonutility Plant* is charged against income over its estimated useful life, using the straight-line method of depreciation. When nonutility property is retired, or otherwise disposed of, the asset and accumulated depreciation are removed, and the resulting gain or loss is reflected in income, typically impacting operating expenses.

Impairment Reviews

Property, plant and equipment along with other long-lived assets are reviewed as facts and circumstances indicate that the carrying amount may be impaired. This impairment review involves the comparison of an asset's (or group of assets') carrying value to the estimated future cash flows the asset (or asset group) is expected to generate over a remaining life. If this evaluation were to conclude that the carrying value is impaired, an impairment charge would be recorded based on the difference between the carrying amount and its fair value (less costs to sell for assets to be disposed of by sale) as a charge to operations or discontinued operations.

Investments in Unconsolidated Affiliates

Investments in unconsolidated affiliates where the Company has significant influence are accounted for using the equity method of accounting. The Company's share of net income or loss from these investments is recorded in *Equity in earnings (losses) of unconsolidated affiliates*. Dividends are recorded as a reduction of the carrying value of the investment when received. *Investments in unconsolidated affiliates* where the Company does not have significant influence are accounted for using the cost method of accounting. Dividends associated with cost method investments are recorded as *Other income – net* when received. Investments are reviewed as facts and circumstances indicate that the carrying amount may be impaired. This impairment review involves the comparison of an investment's fair value to its carrying value. Investments, when necessary, include adjustments for declines in value judged to be other than temporary.

Goodwill

Goodwill recorded on the *Consolidated Balance Sheets* results from business acquisitions and is based on a fair value allocation of the businesses' purchase price at the time of acquisition. Goodwill is charged to expense only when it is impaired. The Company tests its goodwill for impairment at an operating segment level because the components within the segments are similar. These tests are performed at least annually and at the beginning of each year. Impairment reviews consist of a comparison of fair value to the carrying amount. If the fair value is less than the carrying amount, an impairment loss is recognized in operations. No goodwill impairments have been recorded during the periods presented.

Regulation

Retail public utility operations affecting Indiana customers are subject to regulation by the IURC, and retail public utility operations affecting Ohio customers are subject to regulation by the PUCO. The Company's accounting policies give recognition to the ratemaking and accounting practices authorized by these agencies.

Refundable or Recoverable Gas Costs & Cost of Fuel & Purchased Power

All metered gas rates in Indiana contain a gas cost adjustment clause that allows the Company to charge for changes in the cost of purchased gas. Metered electric rates contain a fuel adjustment clause that allows for adjustment in charges for electric energy to reflect changes in the cost of fuel. The net energy cost of purchased power, subject to a variable benchmark based on NYMEX natural gas prices, is also recovered through regulatory proceedings. The Company records any under-or-over-recovery resulting from gas and fuel adjustment clauses each month in revenues. A corresponding asset or liability is recorded until the under-or-over-recovery is billed or refunded to utility customers. The cost of gas sold is charged to operating expense as delivered to customers, and the cost of fuel and purchased power for electric generation is charged to operating expense when consumed.

Regulatory Assets & Liabilities

Regulatory assets represent certain incurred costs, which will result in probable future cash recoveries from customers through the ratemaking process. Regulatory liabilities represent probable expenditures by the Company for removal costs or future reductions in revenues associated with amounts that are to be credited to customers through the ratemaking process. The Company continually assesses the recoverability of costs recognized as regulatory assets and liabilities and the ability to recognize new regulatory assets and liabilities associated with its regulated utility operations. Given the current regulatory environment in its jurisdictions, the Company believes such accounting is appropriate.

The Company collects an estimated cost of removal of its utility plant through depreciation rates established in regulatory proceedings. The Company records amounts expensed in advance of payments as a *Regulatory liability* because the liability does not meet the threshold of an asset retirement obligation.

Postretirement Obligations & Costs

The Company recognizes the funded status of its pension plans and postretirement plans on its balance sheet. The funded status of a defined benefit plan is its assets (if any) less its projected benefit obligation (PBO), which reflects service accrued to date and includes the impact of projected salary increases (for pay-related benefits). The funded status of a postretirement plan is its assets (if any) less its accumulated postretirement benefit obligation (APBO), which reflects accrued service to date. To the extent this obligation exceeds amounts previously recognized in the statement of income, the Company records a *Regulatory asset* for that portion related to its rate regulated utilities. To the extent that excess liability does not relate to a rate regulated utility, the offset is recorded as a reduction to equity in *Accumulated other comprehensive income*.

The annual cost of all postretirement plans is recognized in operating expenses or capitalized to plant following the direct labor of current employees. Specific to pension plans, the Company uses the projected unit credit actuarial cost method to calculate service cost and the PBO. This method projects the present value of benefits at retirement and allocates that cost over the projected years of service. Annual service cost represents one year's benefit accrual while the PBO represents benefits allocated to previously accrued service. For other postretirement plans, service cost is calculated by dividing the present value of a participant's projected postretirement benefits into equal parts based upon the number of years between a participant's hire date and first eligible retirement date. Annual service cost represents one year's benefit accrual while the APBO represents benefit allocated to previously accrued service. To calculate the expected return on pension plan assets, the Company uses the plan assets' market-related value and an expected long-term rate of return. For the majority of the Company's pension plans, the fair market value of the assets at the balance sheet date is adjusted to a market-related value by recognizing the change in fair value experienced in a given year ratably over a five-year period. Interest cost represents the annual accretion of the PBO and APBO at the discount rate. Actuarial gains and losses outside of a corridor (equal to 10 percent of the greater of the benefit obligation and the market-related value of assets) are amortized over the expected future working lifetime of active participants (except for plans where almost all participants are inactive). Prior service costs related to plan changes are amortized over the expected future working lifetime (or to full eligibility date for postretirement plan other than pensions) of the active participants at the time of the amendment.

Asset Retirement Obligations

A portion of removal costs related to interim retirements of gas utility pipeline and utility poles, certain asbestos-related issues, and reclamation activities meet the definition of an asset retirement obligation (ARO). The Company records the fair value of a liability for a legal ARO in the period in which it is incurred. When the liability is initially recorded, the Company capitalizes a cost by increasing the carrying amount of the related long-lived asset. The liability is accreted, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company settles the obligation for its recorded amount or incurs a gain or loss. To the extent regulation is involved, regulatory assets and liabilities result when accretion and amortization is adjusted to match rates established by regulators and any gain or loss is subject to deferral.

Product Warranties, Performance Guarantees & Other Guarantees

Liabilities and expenses associated with product warranties and performance guarantees are recognized based on historical experience at the time the associated revenue is recognized. Adjustments are made as changes become reasonably estimable. The Company does not recognize the fair value of an obligation at inception for these guarantees because they are guarantees of the Company's own performance and/or product installations.

While not significant for the periods presented, the Company does recognize the fair value of an obligation at the inception of a guarantee in certain circumstances. These circumstances would include executing certain indemnification agreements and guaranteeing operating lease residual values, the performance of a third party, or the indebtedness of a third party.

Energy Contracts & Derivatives

The Company will periodically execute derivative contracts in the normal course of operations while buying and selling commodities to be used in operations, optimizing its generation assets, and managing risk. A derivative is recognized on the balance sheet as an asset or liability measured at its fair market value and the change in the derivative's fair market value depends on the intended use of the derivative and resulting designation.

When an energy contract that is a derivative is designated and documented as a normal purchase or normal sale (NPNS), it is exempt from mark-to-market accounting. Such energy contracts include Real Time and Day Ahead purchase and sale contracts with the MISO, certain natural gas purchases, and wind farm and other electric generating contracts.

When the Company engages in energy contracts and financial contracts that are derivatives and are not subject to the NPNS or other exclusions, such contracts are recorded at market value as current or noncurrent assets or liabilities depending on their value and when the contracts are expected to be settled. Contracts and any associated collateral with counter-parties subject to master netting arrangements are presented net in the *Consolidated Balance Sheets*. The offset resulting from carrying the derivative at fair value on the balance sheet is charged to earnings unless it qualifies as a hedge or is subject to regulatory accounting treatment. The offset to contracts affected by regulatory accounting treatment, which include most of the Company's executed energy and financial contracts, are marked to market as a regulatory asset or liability. Market value for derivative contracts is determined using quoted market prices from independent sources or from internal models. As of and for the periods presented, derivative activity is not material to these financial statements.

Income Taxes

As discussed in Note 8 in the Company's Consolidated Financial Statements included in Item 8, on December 22, 2017, comprehensive federal tax legislation was enacted, referred to as the Tax Cuts and Jobs Act ("TCJA").

Deferred income taxes are provided for temporary differences between the tax basis (adjusted for related unrecognized tax benefits, if any) of an asset or liability and its reported amount in the financial statements. Deferred tax assets and liabilities are computed based on the currently-enacted statutory income tax rates that are expected to be applicable when the temporary differences are scheduled to reverse. The Company's rate regulated utilities recognize regulatory liabilities, to the extent considered in ratemaking, for deferred taxes provided in excess of the current statutory tax rate and regulatory assets for deferred taxes provided at rates less than the current statutory tax rate. Such tax-related regulatory assets and liabilities are reported at the revenue requirement level and amortized to income as the related temporary differences reverse, generally over the lives of the related properties. A valuation allowance is recorded to reduce the carrying amounts of deferred tax assets unless it is more likely than not that the deferred tax assets will be realized.

Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the more-likely-than-not recognition threshold is satisfied and measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement. The Company reports interest and penalties associated with unrecognized tax benefits within *Income taxes* in the *Consolidated Statements of Income* and reports tax liabilities related to unrecognized tax benefits as part of *Deferred credits & other liabilities*.

Investment tax credits (ITCs) are deferred and amortized to income over the approximate lives of the related property. Production tax credits (PTCs) are recognized as energy is generated and sold based on a per kilowatt hour rate prescribed in applicable federal and state statutes.

Revenues

Most revenues are recognized as products and services are delivered to customers. Some nonutility revenues are recognized using the percentage of completion method. The Company records revenues for services and goods delivered but not billed at the end of an accounting period in *Accrued unbilled revenues*.

MISO Transactions

With the IURC's approval, the Company is a member of the MISO, a FERC approved regional transmission organization. The MISO serves the electrical transmission needs of much of the Midcontinent region and maintains operational control over the Company's electric transmission facilities as well as that of other utilities in the region. The Company is an active participant in the MISO energy markets, bidding its owned generation into the Day Ahead and Real Time markets and procuring power for its retail customers at Locational Marginal Pricing (LMP) as determined by the MISO market.

MISO-related purchase and sale transactions are recorded using settlement information provided by the MISO. These purchase and sale transactions are accounted for on a net hourly position. Net purchases in a single hour are recorded in *Cost of fuel & purchased power* and net sales in a single hour are recorded in *Electric utility revenues*. On occasion, prior period transactions are resettled outside the routine process due to a change in the MISO's tariff or a material interpretation thereof. Expenses associated with resettlements are recorded once the resettlement is probable and the resettlement amount can be estimated. Revenues associated with resettlements are recognized when the amount is determinable and collectability is reasonably assured.

The Company also receives transmission revenue that results from other members' use of the Company's transmission system. These revenues are also included in *Electric utility revenues.* Generally, these transmission revenues along with costs charged by the MISO are considered components of base rates and any variance from that included in base rates is recovered from / refunded to retail customers through tracking mechanisms.

Share-Based Compensation

The Company grants share-based awards to certain employees and board members. Liability classified share-based compensation awards are re-measured at the end of each period based on an expected settlement date fair value. Equity classified share-based compensation awards are measured at the grant date, based on the fair value of the award. Expense associated with share-based awards is recognized over the requisite service period, which generally begins on the date the award is granted through the earlier of the date the award vests or the date the employee becomes retirement eligible.

Excise & Utility Receipts Taxes

Excise taxes and a portion of utility receipts taxes are included in rates charged to customers. Accordingly, the Company records these taxes received as a component of operating revenues, which totaled $29.1 million in 2017, $28.3 million in 2016, and $29.4 million in 2015. Expense associated with excise and utility receipts taxes are recorded as a component of *Taxes other than income taxes*.

Operating Segments

The Company's chief operating decision maker is the Chief Executive Officer. The Company uses net income calculated in accordance with generally accepted accounting principles as its most relevant performance measure. The Company has three operating segments within its Utility Group, three operating segments in its Nonutility Group, and a Corporate and Other segment.

Fair Value Measurements

Certain assets and liabilities are valued and disclosed at fair value. Financial assets include securities held in trust by the Company's pension plans. Nonfinancial assets and liabilities include the initial measurement of an asset retirement obligation or the use of fair value in goodwill, intangible assets, and long-lived assets impairment tests. FASB guidance provides the framework for measuring fair value. That framework provides a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). The three levels of the fair value hierarchy are described as follows:

Level 1 — Inputs to the valuation methodology are unadjusted quoted prices for identical assets or liabilities in active markets that the Company has the ability to access.

Level 2 — Inputs to the valuation methodology include

- quoted prices for similar assets or liabilities in active markets;
- quoted prices for identical or similar assets or liabilities in inactive markets;
- inputs other than quoted prices that are observable for the asset or liability;
- inputs that are derived principally from or corroborated by observable market data by correlation or other means.

If the asset or liability has a specified (contractual) term, the Level 2 input must be observable for substantially the full term of the asset or liability.

Level 3 — Inputs to the valuation methodology are unobservable and significant to the fair value measurement.

The asset or liability's fair value measurement level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. Valuation techniques used maximize the use of observable inputs and minimize the use of unobservable inputs.

3. Utility & Nonutility Plant

The original cost of *Utility Plant*, together with depreciation rates expressed as a percentage of original cost, follows:

(In millions)	At December 31, 2017 Original Cost	2017 Depreciation Rates as a Percent of Original Cost	2016 Original Cost	2016 Depreciation Rates as a Percent of Original Cost
Gas utility plant	$ 3,969.6	3.4%	$ 3,587.5	3.4%
Electric utility plant	2,833.5	3.3%	2,752.0	3.3%
Common utility plant	59.0	3.2%	56.3	3.2%
Construction work in progress	70.7	—	63.0	—
Asset retirement obligations	82.6	—	86.6	—
Total original cost	**$ 7,015.4**		**$ 6,545.4**	

SIGECO and Alcoa Generating Corporation (AGC), a subsidiary of Alcoa, Inc. (Alcoa), own a 300 MW unit at the Warrick Power Plant (Warrick Unit 4) as tenants in common. SIGECO's share of the cost of this unit at December 31, 2017, is $191.0 million with accumulated depreciation totaling $119.7 million. AGC and SIGECO share equally in the cost of operation and output of the unit. SIGECO's share of operating costs is included in *Other operating expenses* in the *Consolidated Statements of Income*.

Nonutility Plant, net of accumulated depreciation and amortization follows:

(In millions)	At December 31, 2017	2016
Vehicles & equipment	$220.2	$207.4
Computer hardware & software	156.5	121.8
Land & buildings	77.1	77.9
All other	10.3	16.8
Nonutility plant - net	**$464.1**	**$423.9**

Nonutility Plant is presented net of accumulated depreciation and amortization of $506.9 million and $460.8 million as of December 31, 2017 and 2016, respectively. For the years ended December 31, 2017, 2016, and 2015, the Company capitalized interest totaling $1.2 million, $1.0 million, and $0.4 million, respectively, on nonutility plant construction projects.

In 2016, the estimated depreciable lives for certain pieces of equipment at Minnesota Limited, LLC were reevaluated and extended due to a change in service life of the equipment. As a result of this evaluation, the Company extended the estimated useful life of certain pieces of equipment effective January 1, 2016. The effect of this change in estimate was a reduction of annual depreciation expense of approximately $9.6 million.

4. Regulatory Assets & Liabilities

Regulatory Assets

Regulatory assets consist of the following:

(In millions)	At December 31, 2017	2016
Future amounts recoverable from ratepayers related to:		
Benefit obligations (See Note 9)	$102.8	$102.6
Net deferred income taxes (See Note 8)	6.2	(17.1)
Asset retirement obligations & other	24.3	—
	133.3	85.5
Amounts deferred for future recovery related to:		
Cost recovery riders & other	142.4	91.6
	142.4	91.6
Amounts currently recovered in customer rates related to:		
Indiana authorized trackers	75.9	64.2
Ohio authorized trackers	28.4	22.2
Loss on reacquired debt & hedging costs	22.7	24.1
Deferred coal costs and other	14.1	21.2
	141.1	131.7
Total regulatory assets	**$416.8**	**$308.8**

Of the $141 million currently being recovered in customer rates, no amounts are earning a return. The weighted average recovery period of regulatory assets currently being recovered in base rates, which totals $23 million, is 20 years. The remainder of the regulatory assets are being recovered timely through periodic recovery mechanisms. The Company has rate orders for all deferred costs not yet in rates and therefore believes that future recovery is probable.

Assets arising from benefit obligations represent the funded status of retirement plans less amounts previously recognized in the statement of income. The Company records a *Regulatory asset* for that portion related to its rate regulated utilities. See Note 09.

Regulatory assets for asset retirement obligations are a result of costs incurred for expected retirement activity for the Company's ash ponds beyond what has been recovered in rates. The Company believes the recovery of these assets are probable as the costs are currently being recovered in rates.

Regulatory Liabilities

At December 31, 2017 and 2016, the Company had regulatory liabilities of approximately $937 million and $454 million, respectively, $477 million and $452 million of which related to cost of removal obligations, and at December 31, 2017, $459 million to deferred taxes. The deferred tax related regulatory liability is primarily the result of the $446 million revaluation of deferred taxes at December 31, 2017 at the reduced federal corporate tax rate. These regulatory liabilities are expected to be refunded to customers over time following state regulator approval.

5. Investment in ProLiance Holdings, LLC

The Company has an investment in ProLiance Holdings, LLC (ProLiance), an affiliate of the Company and Citizens Energy Group (Citizens). Much of the ProLiance business was sold on June 18, 2013 when ProLiance exited the natural gas marketing business through the disposition of certain of the net assets of its energy marketing business, ProLiance Energy, LLC. The Company's remaining investment in ProLiance relates primarily to an investment in LA Storage, LLC (LA Storage). Consistent with its ownership percentage, the Company is allocated 61 percent of ProLiance's profits and losses; however, governance and voting rights remain at 50 percent for each member, and therefore, the Company accounts for its investment in ProLiance using the equity method of accounting.

The Company's remaining investment at December 31, 2017, shown at its 61 percent ownership share of the individual net assets of ProLiance, is as follows.

(In millions)		As of December 31, 2017
Cash	$	0.8
Investment in LA Storage		22.4
Total investment in ProLiance	$	23.2
Included in:		
Investments in unconsolidated affiliates	$	18.8
Other nonutility investments	$	4.4

LA Storage, LLC Storage Asset Investment

ProLiance Transportation and Storage, LLC (PT&S), a subsidiary of ProLiance, and Sempra Energy International (SEI), a subsidiary of Sempra Energy (SE), through a joint venture, have a 100 percent interest in a development project for salt-cavern natural gas storage facilities known as LA Storage. PT&S is the minority member with a 25 percent interest, which it accounts for using the equity method. The project, which includes a pipeline system, is expected to include 12-19 Bcf of storage capacity, and has the potential for further expansion. This pipeline system is currently connected with several interstate pipelines, including the Cameron Interstate Pipeline operated by Sempra Pipelines & Storage, and can connect area liquefied natural gas regasification terminals to an interstate natural gas transmission system and storage facilities.

Approximately 12 Bcf of the storage, which comprises three of the four FERC certified caverns, is fully tested but additional work is required to further develop the caverns. The timing and extent of development of these caverns and pipeline system is dependent on market conditions, including pricing, need for storage and transmission capacity, and development of the liquefied natural gas market, among other factors. To date, development activity has been modest due to the current low demand for storage facilities. The development of the storage market and related pricing are critical assumptions in the analysis of the recoverability of the investment's carrying value. At December 31, 2017 and 2016, ProLiance's investment in the joint venture was $36.8 million and $36.7 million, respectively.

6. Nonutility Legacy Holdings

Within the nonutility group, there are legacy investments involved in other ventures. As of December 31, 2017 and 2016, total remaining legacy investments, other than the investment in ProLiance, included in the Other Businesses portfolio totaled $6.7 million and $7.0 million, respectively.

For the period presented, the remaining investment relates to a debt security related to the sale of commercial real estate of $5.1 million and other investments of $1.6 million. During 2015, the Company sold its investment in commercial real estate property and holds a debt security related to that transaction.

7. Intangible Assets

Intangible assets, which are included in *Other assets*, consist of the following:

(In millions)	At December 31,			
	2017		2016	
	Amortizing	Non-amortizing	Amortizing	Non-amortizing
Customer-related assets	$ 18.6	$ —	$ 20.9	$ —
Market-related assets	6.6	6.0	—	13.0
Intangible assets, net	**$ 25.2**	**$ 6.0**	**$ 20.9**	**$ 13.0**

Effective January 1, 2017, the Company reclassified an approximate $7 million market-related asset from non-amortizing to amortizing. As of December 31, 2017, the weighted average remaining life for amortizing customer-related assets is 13 years. These amortizing intangible assets have no significant residual values. Intangible assets are presented net of accumulated amortization totaling $14.6 million for customer-related assets and $4.3 million for market-related assets at December 31, 2017 and $12.0 million for customer-related assets and $4.5 million for market-related assets at December 31, 2016. Annual amortization associated with intangible assets totaled $2.6 million in 2017, $2.5 million in 2016 and $3.1 million in 2015. Amortization should approximate (in millions) $2.6 per year from 2018 through 2022. Intangible assets are primarily in the Nonutility Group.

8. Income Taxes

Tax Cuts and Jobs Act

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 are 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 under Section 118 of the IRC regarding taxability of contributions made by government or civic groups.

Consolidated results reflect a net tax benefit of $45.3 million for the period ending December 31, 2017 from the enactment of the TCJA. This benefit is associated with the impact of the corporate rate reduction on the Company’s deferred income tax balances resulting in a $23.2 million benefit for the Utility Group, $22.3 million benefit for the Nonutility businesses, and $0.2 million expense for Corporate & Other. The portion of the benefit attributable to Utility Group operations relates to assets which are not included for regulatory rate making purposes, such as goodwill associated with past acquisitions.

In addition, the reduction in the federal corporate rate results in $333.4 million in excess federal deferred income taxes for the Utility Group.

The Company’s gas and electric utilities currently recover corporate income tax expense in Commission approved rates charged to customers. The IURC and 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 expects to initiate proceedings to effect the timely reduction in customer bills due to the lower corporate federal income tax rate in the very near term. In Ohio, in response to the PUCO’s request for comments from utilities, Vectren submitted its response indicating that the issues should be address in its base rate case, for which the pre-filing notice was filed February 21, 2018.

A reconciliation of the federal statutory rate to the effective income tax rate follows:

	Year Ended December 31,		
	2017	2016	2015
Statutory rate:	35.0%	35.0%	35.0%
State & local taxes-net of federal benefit	3.4	2.8	3.6
Deferred tax revaluation-tax law change	(17.3)	—	—
Amortization of investment tax credit	(0.2)	(0.3)	(0.2)
Domestic production deduction	(1.4)	(0.4)	(1.0)
Energy efficiency building deductions	—	(1.7)	(2.3)
Research and development credit	(0.3)	(0.6)	(1.6)
Other tax credits	(0.1)	(0.1)	(0.1)
All other-net	(1.4)	0.1	0.2
Effective tax rate	**17.7%**	**34.8%**	**33.6%**

On February 9, 2018, through the signing into law of the Bipartisan Budget Act of 2018, Section 179D of the Internal Revenue Code, which provides for the energy efficiency commercial buildings tax deduction, was retroactively extended to 2017 for one year. Any impacts will be reflected in 2018 results pursuant to ASC 740 related to accounting for retroactive effects of legislation.

Significant components of the net deferred tax liability follow:

(In millions)	At December 31, 2017	At December 31, 2016
Noncurrent deferred tax liabilities (assets):		
Depreciation & cost recovery timing differences	$ 593.7	$902.4
Regulatory assets recoverable through future rates	7.9	17.6
Alternative minimum tax carryforward	(12.2)	(29.3)
Employee benefit obligations	(9.3)	(8.1)
Net operating loss & other carryforwards (net of valuation allowances)	(4.1)	(3.2)
U.S. federal charitable contributions carryforwards	(12.2)	—
Regulatory liabilities to be settled through future rates	(116.2)	(15.9)
Impairments	(0.6)	(2.5)
Deferred fuel costs-net	16.2	25.9
Other-net	28.1	18.8
Net noncurrent deferred tax liability	**$ 491.3**	**$905.7**

At December 31, 2017 and 2016, investment tax credits totaling $1.2 million and $1.6 million respectively, are included in *Deferred credits & other liabilities*. At December 31, 2017, the Company has alternative minimum tax credit carryforwards which do not expire. The TCJA eliminated the alternative minimum tax after 2017. Pursuant to the TCJA, the Company will be able to recover its alternative minimum tax carryforwards in future periods.

In addition, the Company has $4.1 million in state net operating losses and $12.2 million in U.S. federal charitable contributions carryforwards, which will expire in 5 to 20 years. The net operating loss carryforward and other carryforwards were reduced for the impacts of unrecognized tax benefits and a valuation allowance relating primarily to state net operating loss carryforwards. At December 31, 2017 and 2016, the valuation allowance was $10.1 million and $8.3 million, respectively.

The components of income tax expense follow:

(In millions)	Year Ended December 31, 2017	2016	2015
Current:			
Federal	$20.5	$ 6.8	$10.8
State	6.9	6.0	8.5
Total current taxes	**27.4**	**12.8**	**19.3**
Deferred:			
Federal	16.7	97.6	79.0
State	2.7	3.6	2.0
Total deferred taxes	**19.4**	**101.2**	**81.0**
Amortization of investment tax credits	(0.4)	(1.1)	(0.6)
Total income tax expense	**$46.4**	**$112.9**	**$99.7**

Uncertain Tax Positions

Unrecognized tax benefits for all periods presented were not material to the Company. The net liability on the *Consolidated Balance Sheet* for unrecognized tax benefits inclusive of interest and penalties totaled $1.3 million and $1.2 million, respectively, at December 31, 2017 and 2016.

The Company and/or certain of its subsidiaries file income tax returns in the U.S. federal jurisdiction and various states. The Internal Revenue Service (IRS) has concluded examinations of the Company's U.S. federal income tax returns for tax years through December 31, 2012. The State of Indiana, the Company's primary state tax jurisdiction, has conducted examinations of state income tax returns for tax years through December 31, 2010. The statutes of limitations for assessment of federal income tax and Indiana income tax have expired with respect to tax years through 2014 except to the extent of refunds claimed on amended tax returns. The statutes of limitations for assessment of the 2013 tax year related to the amended federal return will expire in 2020. The statutes of limitations for assessment of the 2009 and 2011 through 2014 tax years related to the amended Indiana income tax returns will expire in 2018 through 2020.

Indiana Senate Bill 1

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

9. Retirement Plans & Other Postretirement Benefits

At December 31, 2017, the Company maintains three closed qualified defined benefit pension plans, a nonqualified supplemental executive retirement plan (SERP), and a postretirement benefit plan. The defined benefit pension plans and postretirement benefit plan, which cover eligible full-time regular employees, are primarily noncontributory. The postretirement benefit plan includes health care and life insurance benefits which are a combination of self-insured and fully insured programs. The qualified pension plans and the SERP are aggregated under the heading "Pension Benefits." The postretirement benefit plan is presented under the heading "Other Benefits."

Net Periodic Benefit Costs

A summary of the components of net periodic benefit cost for the three years ended December 31, 2017 follows:

	Pension Benefits			Other Benefits		
(In millions)	2017	2016	2015	2017	2016	2015
Service cost	$ 6.5	$ 7.0	$ 7.9	$ 0.2	$ 0.3	$ 0.4
Interest cost	13.7	14.7	14.6	1.5	1.7	2.0
Expected return on plan assets	(21.0)	(22.8)	(22.5)	—	—	—
Amortization of prior service cost (benefit)	0.4	0.4	0.7	(2.4)	(2.9)	(3.0)
Amortization of actuarial loss	7.4	7.2	8.5	—	—	0.7
Settlement charge	2.1	—	0.6	—	—	—
Net periodic benefit cost (benefit)	**$ 9.1**	**$ 6.5**	**$ 9.8**	**$(0.7)**	**$(0.9)**	**$ 0.1**

A portion of the net periodic benefit cost disclosed in the table above is capitalized as *Utility Plant* following the allocation of current employee labor costs. Costs capitalized in 2017, 2016, and 2015 are estimated at $3.0 million, $1.9 million, and $3.1 million, respectively.

The Company decreased the weighted average discount rate used to measure periodic cost from 4.31 percent in 2016 to 4.07 percent in 2017 due to lower benchmark interest rates that approximated the expected duration of the Company's benefit obligations as of that valuation date. The Company derives its discount rate by identifying a theoretical settlement portfolio of high quality corporate bonds sufficient to provide for the plans' projected benefit payments. For fiscal year 2018, the weighted average discount rate assumption will decrease to 3.61 percent for the defined benefit pension plans, based on decreased benchmark interest rates.

The weighted averages of significant assumptions used to determine net periodic benefit costs follow:

	Pension Benefits			Other Benefits		
	2017	2016	2015	2017	2016	2015
Discount rate	4.07%	4.31%	4.05%	4.04%	4.21%	3.95%
Rate of compensation increase	3.50%	3.50%	3.50%	N/A	N/A	N/A
Expected return on plan assets	7.00%	7.50%	7.50%	N/A	N/A	N/A
Expected increase in Consumer Price Index	N/A	N/A	N/A	2.50%	2.50%	2.50%

The Company uses a "building block" approach to develop an expected long-term rate of return. In 2017, the Company lowered to 7.0 percent this long-term assumption based on continued lower interest rates. The 2018 assumption is also 7.0 percent. Health care cost trend rate assumptions do not have a material effect on the service and interest cost components of benefit costs. The Company's plans limit its exposure to increases in health care costs to annual changes in the Consumer Price Index (CPI). Any increase in health care costs in excess of the CPI increase is the responsibility of the plan participants.

Projected Benefit Obligations

A reconciliation of the Company's benefit obligations at December 31, 2017 and 2016 follows:

	Pension Benefits		Other Benefits	
(In millions)	2017	2016	2017	2016
Projected benefit obligation, beginning of period	$350.4	$348.3	$40.5	$43.5
Service cost – benefits earned during the period	6.5	7.0	0.2	0.3
Interest cost on projected benefit obligation	13.7	14.7	1.5	1.7
Plan participants' contributions	—	—	1.2	1.1
Plan amendments	1.4	—	—	—
Actuarial loss (gain)	25.4	8.7	1.3	(1.6)
Settlement loss	0.5	—	—	—
Benefit payments	(31.4)	(28.3)	(4.7)	(4.5)
Projected benefit obligation, end of period	**$366.5**	**$350.4**	**$40.0**	**$40.5**

The increase in the projected benefit obligation in 2017 is primarily due to a decrease in the discount rate used to measure the obligation at year end. The accumulated benefit obligation for all defined benefit pension plans was $356.5 million and $339.8 million at December 31, 2017 and 2016, respectively. The accumulated benefit obligation as of a date is the actuarial present value of benefits attributed by the pension benefit formula to employee service rendered prior to that date and based on current and past compensation levels. The accumulated benefit obligation differs from the projected benefit obligation disclosed in the table above in that it includes no assumptions about future compensation levels.

Material Assumptions

The benefit obligation as of December 31, 2017 and 2016 was calculated using the following weighted average assumptions:

	Pension Benefits		Other Benefits	
	2017	2016	2017	2016
Discount rate	3.61%	4.07%	3.57%	4.04%
Rate of compensation increase	3.50%	3.50%	N/A	N/A
Expected increase in Consumer Price Index	N/A	N/A	2.50%	2.50%

For the projected benefit obligation calculation at December 31, 2017, the mortality assumed for determining future lump sums reflects the latest IRS mortality table (2019) and the latest mortality improvement scales released by the Society of Actuaries. To calculate the 2017 ending postretirement benefit obligation, medical claims costs in 2018 were assumed to be 7.0 percent higher than those incurred in 2017. That trend, beginning at 7.0 percent in 2018, is assumed to reach its ultimate trending increase of 5.0 percent by 2025 and remain level thereafter. A one-percentage point increase or decrease in assumed health care cost trend rates would have changed the benefit obligation by approximately $0.2 million.

Plan Assets

A reconciliation of the Company's plan assets at December 31, 2017 and 2016 follows:

	Pension Benefits		Other Benefits	
(In millions)	2017	2016	2017	2016
Plan assets at fair value, beginning of period	$304.5	$296.9	$—	$—
Actual return on plan assets	41.9	19.7	—	—
Employer contributions	1.1	16.2	3.5	3.4
Plan participants' contributions	—	—	1.2	1.1
Benefit payments	(31.4)	(28.3)	(4.7)	(4.5)
Fair value of plan assets, end of period	**$316.1**	**$304.5**	**$—**	**$—**

The Company's overall investment strategy for its retirement plan trusts is to maintain investments in a diversified portfolio, comprised of primarily equity and fixed income investments, which are further diversified among various asset classes. The diversification is designed to minimize the risk of large losses while maximizing total return within reasonable and prudent levels of risk. The investment objectives specify a targeted investment allocation for the pension plans of 60 percent equities, 35 percent debt, and 5 percent for other investments, including real estate. Both the equity and debt securities have a blend of domestic and international exposures. Objectives do not target a specific return by asset class. The portfolios' return is monitored in total. Following is a description of the valuation methodologies used for trust assets measured at fair value.

Mutual Funds

The fair values of mutual funds are derived from the daily closing price as reported by the fund as these instruments have active markets (Level 1 inputs).

Common Collective Trust Funds (CTF's)

The Company's plans have investments in trust funds similar to mutual funds in that they are created by pooling of funds from investors into a common trust and such funds are managed by a third party investment manager. These trust funds typically give investors a wider range of investment options through this pooling of funds than those generally available to investors on an individual basis. However, unlike mutual funds, these trusts are not publicly traded in an active market. The funds are valued at the net asset value of the underlying investments. The net asset value is used as a practical expedient to estimate fair value. In relation to these investments, there are no unfunded commitments. Also, the Plan can exchange shares with minimal restrictions, however, certain events may exist where share exchanges are restricted for up to 31 days.

The fair values of the Company's pension and other retirement plan assets at December 31, 2017 and December 31, 2016 by asset category and by fair value hierarchy are as follows:

(In millions)	As of December 31, 2017 Level 1	Level 2	Level 3	Total
Domestic equity funds	$140.2	$ —	$ —	$140.2
International equity funds	46.8	—	—	46.8
Bond funds	43.6	—	—	43.6
Real estate, commodity & other funds	6.2	—	4.5	10.7
Investments measured at net asset value (a)	—	—	—	74.8
Total plan investments	**$236.8**	**$ —**	**$ 4.5**	**$316.1**

(In millions)	As of December 31, 2016 Level 1	Level 2	Level 3	Total
Domestic equity funds	$135.1	$ —	$ —	$135.1
International equity funds	42.0	—	—	42.0
Bond funds	44.6	—	—	44.6
Real estate, commodity & other funds	6.0	—	4.4	10.4
Investments measured at net asset value (a)	—	—	—	72.4
Total plan investments	**$227.7**	**$ —**	**$ 4.4**	**$304.5**

(a) In accordance with Subtopic 820-10, certain investments that were measured at net asset value per share, or its equivalent, have not been classified in the fair value hierarchy.

Guaranteed Annuity Contract

One of the Company's pension plans is party to a group annuity contract with John Hancock Life Insurance Company (John Hancock). At December 31, 2017 and 2016, the estimate of undiscounted funds necessary to satisfy John Hancock's remaining obligation was $4.2 million and $4.0 million, respectively. If funds retained by John Hancock are not sufficient to satisfy retirement payments due to these retirees, the shortfall must be funded by the Company. The composite investment return, net of manager fees and other charges for the years ended December 31, 2017 and 2016 was 3.25 percent and 3.60 percent, respectively. The Company values this illiquid investment using long-term interest rate and mortality assumptions, among others, and is therefore considered a Level 3 investment. There is no unfunded commitment related to this investment.

A roll forward of the fair value of the guaranteed annuity contract calculated using Level 3 valuation assumptions follows:

(In millions)	2017	2016
Fair value, beginning of year	$ 4.4	$ 4.3
Unrealized gains related to investments still held at reporting date	0.2	0.2
Purchases, sales & settlements, net	(0.1)	(0.1)
Fair value, end of year	**$ 4.5**	**$ 4.4**

Funded Status

The funded status of the plans as of December 31, 2017 and 2016 follows:

(In millions)	Pension Benefits 2017	Pension Benefits 2016	Other Benefits 2017	Other Benefits 2016
Qualified Plans				
Projected benefit obligation, end of period	$(343.4)	$(329.7)	$(40.0)	$(40.5)
Fair value of plan assets, end of period	316.1	304.5	—	—
Funded Status of Qualified Plans, end of period	(27.3)	(25.2)	(40.0)	(40.5)
Projected benefit obligation of SERP Plan, end of period	(22.9)	(20.6)	—	—
Total funded status, end of period	**$ (50.2)**	**$ (45.8)**	**$(40.0)**	**$(40.5)**
Accrued liabilities	$ 1.1	$ 1.2	$ 4.1	$ 4.5
Deferred credits & other liabilities	$ 49.1	$ 44.6	$ 35.9	$ 36.0

Expected Cash Flows

The Company expects to make contributions totaling $3.5 million to the qualified pension plans in 2018. In addition, the Company expects to make contributions totaling approximately $1.1 million into the SERP plan and approximately $2.9 million into the postretirement plan.

Estimated retiree pension benefit payments, including the SERP, projected to be required during the years following 2017 are approximately (in millions) $28.8 in 2018, $43.0 in 2019, $30.1 in 2020, $27.3 in 2021, $28.6 in 2022, and $132.7 in years 2023-2027. Expected benefit payments projected to be required for postretirement benefits during the years following 2017 (in millions) are approximately $4.1 in 2018, $4.4 in 2019, $4.7 in 2020, $4.9 in 2021, $4.9 in 2022, and $23.1 in years 2023-2027.

Prior Service Cost and Actuarial Gains and Losses

Following is a roll forward of prior service cost and actuarial gains and losses.

(In millions)	Pensions Prior Service Cost	Pensions Net (Gain) or Loss	Other Benefits Prior Service Cost	Other Benefits Net (Gain) or Loss
Balance at January 1, 2015	**$ 2.0**	**$ 111.7**	**$(17.1)**	**$ 10.9**
Amounts arising during the period	0.5	6.9	—	(8.6)
Reclassification to benefit costs	(0.7)	(8.5)	3.0	(0.7)
Balance at December 31, 2015	**$ 1.8**	**$110.1**	**$(14.1)**	**$ 1.6**
Amounts arising during the period	—	11.7	—	(1.6)
Reclassification to benefit costs	(0.4)	(7.2)	2.9	—
Balance at December 31, 2016	**$ 1.4**	**$114.6**	**$(11.2)**	**$ —**
Amounts arising during the period	1.3	3.1	—	1.2
Reclassification to benefit costs	(0.4)	(7.4)	2.4	—
Balance at December 31, 2017	**$ 2.3**	**$110.3**	**$ (8.8)**	**$ 1.2**

Following is a reconciliation of the amounts in *Accumulated other comprehensive income* (AOCI) and *Regulatory assets* related to retirement plan obligations at December 31, 2017 and 2016.

(In millions)	2017		2016	
	Pensions	Other Benefits	Pensions	Other Benefits
Prior service cost	$ 2.3	$ (8.8)	$ 1.4	$ (11.2)
Unamortized actuarial loss	110.3	1.2	114.6	—
	112.6	(7.6)	116.0	(11.2)
Less: *Regulatory asset* deferral	(110.2)	7.4	(113.6)	11.0
***AOCI* before taxes**	**$ 2.4**	**$ (0.2)**	**$ 2.4**	**$ (0.2)**

Related to pension plans, $0.5 million of prior service cost and $8.5 million of actuarial gain/loss is expected to be amortized to cost in 2018. Related to other benefits, no actuarial gain/loss is expected to be amortized to periodic cost in 2018, and $2.2 million of prior service cost is expected to reduce costs in 2018.

Multiemployer Benefit Plan

The Company, through its Infrastructure Services operating segment, participates in several industry wide multiemployer pension plans for its union employees which provide for monthly benefits based on length of service. The risks of participating in multiemployer pension plans are different from the risks of participating in single-employer pension plans in the following respects: 1) assets contributed to the multiemployer plan by one employer may be used to provide benefits to employees of other participating employers, 2) if a participating employer stops contributing to the plan, the unfunded obligations of the plan allocable to such withdrawing employer may be borne by the remaining participating employers, and 3) if the Company ceases its participation in its multiemployer pension plans, the Company may be required to pay those plans an amount based on its allocable share of the underfunded status of the plan, referred to as a withdrawal liability.

Expense is recognized as payments are accrued for work performed or when withdrawal liabilities are probable and estimable. Expense associated with multiemployer plans was $42.1 million, $35.0 million and $32.7 million for the years ended December 31, 2017, 2016, and 2015, respectively. During 2017, the Company made contributions to these multiemployer plans on behalf of employees that participate in approximately 250 local unions. Contracts with these unions are negotiated with trade agreements through two primary contractor associations. These trade agreements have varying expiration dates ranging from 2017 through 2021. The average contribution related to these local unions was less than $0.2 million, and the largest contribution was $4.8 million. Multiple unions can contribute to a single multiemployer plan. The Company made contributions to at least 50 plans in 2017, six of which are considered significant plans based on, among other things, the amount of the contributions, the number of employees participating in the plan, and the funded status of the plan.

The Company’s participation in the significant plans is outlined in the following table. The Employer Identification Number (EIN) / Pension Plan Number column provides the EIN and three digit pension plan numbers. The most recent Pension Protection Act Zone Status available in 2017 and 2016 is for the plan year end at January 31, 2017 and 2016 for the Central Pension Fund, May 31, 2017 and 2016 for the Indiana Laborers Fund, December 31, 2016 and 2015 for the Pipeline Industry Benefit Fund, December 31, 2016 and 2015 for the Laborers District Council & Contractors’ Pension Fund of Ohio, July 31, 2016 and 2015 for the Ohio Operating Engineers Pension Fund and April 30, 2017 and 2016 for the Operating Engineers Local 324 Fringe Benefit Fund respectively. The Company’s participation in the significant plans is outlined in the following table. Generally, plans in the red zone are less than 65 percent funded, plans in the yellow zone are less than 80 percent funded and plans in the green zone are at least 80 percent funded. The FIP/RP Status Pending / Implemented column indicates plans for which a funding improvement plan (“FIP”) or rehabilitation plan (“RP”) is either pending or has been implemented. The multiemployer contributions listed in the table below are the Company’s multiemployer contributions made in 2017, 2016, and 2015.

Federal law requires pension plans in endangered status to adopt a FIP aimed at restoring the financial health of the plan. In December 2014, the Multiemployer Pension Reform Act of 2014 was passed and permanently extended the Pension Protection Act of 2006 multiemployer plan critical and endangered status funding rules, among other things, including providing a provision for a plan sponsor to suspend or reduce benefit payments to preserve plans in critical and declining status.

(In millions)

Pension Fund	EIN/Pension Plan Number	Pension Protection Act Zone Status 2017	Pension Protection Act Zone Status 2016	FIP/RP Status Pending/Implemented	Multiemployer Contributions 2017	Multiemployer Contributions 2016	Multiemployer Contributions 2015	Surcharge Imposed
Central Pension Fund	36-6052390-001	Green	Green	No	$ 9.3	$ 7.4	$ 7.2	No
Indiana Laborers Pension Fund (1)	35-6027150-001	Yellow	Yellow	Implemented	5.0	4.4	4.1	No
Pipeline Industry Benefit Fund	73-6146433-001	Green	Green	No	4.9	3.0	4.0	No
Laborers District Fund of Ohio	31-6129964-001	Green	Green	No	3.3	2.0	1.5	No
Ohio Operating Engineers Pension Fund	31-6129968-001	Green	Green	No	2.8	2.1	2.2	No
Operating Eng. Local 324 Fund (2)	38-1900637-001	Red	Yellow	Implemented	2.5	1.6	1.6	No
Other					14.3	14.5	12.1	
Total Contributions					$42.1	$35.0	$32.7	

(1) The Indiana Laborers Pension Fund was in “endangered” status for the Plan Year ending May 31, 2017. In an effort to improve the Plan’s funding situation, the trustees adopted a FIP on December 17, 2015 and updated on December 20, 2016. The funding improvement period is June 1, 2017 to May 31, 2027 or the date the Fund’s actuary certifies it has emerged from endangered status.

(2) The Operating Engineers Local #324 Fringe Benefits Fund was certified to be in “critical” status for the plan year ending April 30, 2017. In an effort to improve the Plan’s funding situation, on March 17, 2011, the trustees adopted a Plan Amendment, which reduced benefit accruals, eliminated some ancillary benefits, and adopted a rehabilitation plan that will be effective from May 1, 2013 through April 30, 2023 or until the Plan is no longer in critical status. On April 27, 2015, the trustees updated the rehabilitation plan to change the annual standard for meeting the requirements of the rehabilitation plan. The annual standard is that actuarial projections updated for each year show the Fund is expected to remain solvent for a 20-year projection period.

While not considered significant to the Company, there are two plans in red zone status receiving Company contributions. There are five plans where Company contributions exceed 5 percent of each plan’s total contributions and one of these plans was considered significant to the Company.

Defined Contribution Plan

The Company also has defined contribution retirement savings plans qualified under sections 401(a) and 401(k) of the Internal Revenue Code and include an option to invest in Vectren common stock, among other alternatives. During 2017, 2016 and 2015, the Company made contributions to these plans of $13.2 million, $12.1 million, and $11.0 million, respectively.

10. Borrowing Arrangements

Long-Term Debt

Long-term senior unsecured obligations and first mortgage bonds outstanding by subsidiary follow:

(In millions)	At December 31, 2017	2016
Utility Holdings		
Fixed Rate Senior Unsecured Notes		
2018, 5.75%	$ 100.0	$ 100.0
2020, 6.28%	100.0	100.0
2021, 4.67%	55.0	55.0
2023, 3.72%	150.0	150.0
2026, 5.02%	60.0	60.0
2028, 3.20%	45.0	45.0
2032, 3.26%	100.0	—
2035, 6.10%	75.0	75.0
2035, 3.90%	25.0	25.0
2041, 5.99%	35.0	35.0
2042, 5.00%	100.0	100.0
2043, 4.25%	80.0	80.0
2045, 4.36%	135.0	135.0
2047, 3.93%	100.0	—
2055, 4.51%	40.0	40.0
Total Utility Holdings	**1,200.0**	**1,000.0**
Indiana Gas		
Fixed Rate Senior Unsecured Notes		
2025, Series E, 6.53%	10.0	10.0
2027, Series E, 6.42%	5.0	5.0
2027, Series E, 6.68%	1.0	1.0
2027, Series F, 6.34%	20.0	20.0
2028, Series F, 6.36%	10.0	10.0
2028, Series F, 6.55%	20.0	20.0
2029, Series G, 7.08%	30.0	30.0
Total Indiana Gas	**96.0**	**96.0**
SIGECO		
First Mortgage Bonds		
2022, 2013 Series C, current adjustable rate 1.565%, tax-exempt	4.6	4.6
2024, 2013 Series D, current adjustable rate 1.565%, tax-exempt	22.5	22.5
2025, 2014 Series B, current adjustable rate 1.565%, tax-exempt	41.3	41.3
2029, 1999 Series, 6.72%	80.0	80.0
2037, 2013 Series E, current adjustable rate 1.565%, tax-exempt	22.0	22.0
2038, 2013 Series A, 4.00%, tax-exempt	22.2	22.2
2043, 2013 Series B, 4.05%, tax-exempt	39.6	39.6
2044, 2014 Series A, 4.00% tax-exempt	22.3	22.3
2055, 2015 Series Mt. Vernon, 2.375%, tax-exempt	23.0	23.0
2055, 2015 Series Warrick County, 2.375%, tax-exempt	15.2	15.2
Total SIGECO	**292.7**	**292.7**

(In millions)	At December 31, 2017	2016
Vectren Capital Corp.		
Fixed Rate Senior Unsecured Notes		
2017, 3.48%	—	75.0
2019, 7.30%	60.0	60.0
2022, 3.33%	75.0	75.0
2025, 4.53%	50.0	50.0
2030, 3.90%	75.0	75.0
Total Vectren Capital Corp.	**260.0**	**335.0**
Total long-term debt outstanding	**1,848.7**	**1,723.7**
Current maturities of long-term debt	(100.0)	(124.1)
Debt issuance costs	(9.4)	(9.0)
Unamortized debt premium & discount-net	(0.6)	(0.7)
Total long-term debt-net	**$1,738.7**	**$1,589.9**

Utility Holdings Long-Term Debt Issuance

On July 14, 2017, Utility Holdings entered into a private placement Note Purchase Agreement pursuant to which institutional investors agreed to purchase the following tranches of notes: (i) $100 million of 3.26 percent Guaranteed Senior Notes, Series A, due August 28, 2032 and (ii) $100 million of 3.93 percent Guaranteed Senior Notes, Series B, due November 29, 2047. The notes are jointly and severally guaranteed by Indiana Gas, SIGECO, and VEDO, wholly owned subsidiaries of Utility Holdings.

The Series A note proceeds were received on August 28, 2017 and the Series B proceeds were received on November 29, 2017.

SIGECO Variable Rate Tax-Exempt Bonds

On September 14, 2017, the Company, through SIGECO, executed a Bond Purchase and Covenants Agreement (Purchase and Covenants Agreement) providing SIGECO the ability to remarket and/or refinance approximately $152 million of tax-exempt bonds at a variable rate based on one month LIBOR through May 1, 2023 (except for one bond that matures on January 1, 2022).

Bonds remarketed through the Bond Purchase and Covenants Agreement included three issuances that were mandatorily tendered to the Company on September 14, 2017. These were

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

Through the Purchase and Covenants Agreement, on September 22, 2017 SIGECO also extended the mandatory tender date of its variable rate 2014 Series B Notes with a principal of $41.3 million and final maturity date of July 1, 2025. (The original tender date was September 24, 2019).

The Purchase and Covenants Agreement provides the option, subject to satisfaction of customary conditions precedent, for the lenders to purchase from SIGECO and for SIGECO to convert to a variable rate other currently outstanding fixed rate, tax-exempt bonds that are callable at SIGECO’s option in March 2018 (2013 Series A Notes totaling $22.2 million due March 1, 2038) and May 2018 (2013 Series B Notes totaling $39.6 million due by May 1, 2043).

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, as described in Note 10, 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 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.

Vectren Capital Unsecured Note Retirements

On December 15, 2017 and March 11, 2016, Vectren Capital senior unsecured notes matured totaling $75 million and $60 million, respectively. Interest rates on the matured bonds were 3.48 percent and 6.92 percent, respectively. The repayment of debt was funded from the Company's cash on hand and Nonutility short-term borrowing arrangements.

SIGECO Bond Retirement

On June 1, 2016, a $13 million SIGECO bond matured. The First Mortgage Bond, which was a portion of an original $25 million public issuance sold on June 1, 1986, carried a fixed interest rate of 8.875 percent. The repayment of debt was funded from the Company's commercial paper program.

Mandatory Tenders

At December 31, 2017, certain series of SIGECO bonds, aggregating $124.0 million are subject to mandatory tenders prior to the bonds' final maturities. $38.2 million will be tendered in 2020 and $85.8 million will be tendered in 2023.

Call Options

At December 31, 2017, certain series of SIGECO bonds, aggregating $84.1 million may be called at SIGECO's option. $61.8 million is callable in 2018, as previously noted, and $22.3 million is callable in 2019.

Future Long-Term Debt Sinking Fund Requirements and Maturities

The annual sinking fund requirement of SIGECO's first mortgage bonds is 1 percent of the greatest amount of bonds outstanding under the Mortgage Indenture. This requirement may be satisfied by certification to the Trustee of unfunded property additions in the prescribed amount as provided in the Mortgage Indenture. SIGECO met the 2017 sinking fund requirement by this means and, expects to also meet this requirement in 2018 in this manner. Accordingly, the sinking fund requirement is excluded from *Current liabilities* in the *Consolidated Balance Sheets*. At December 31, 2017, $1.5 billion of SIGECO's utility plant remained unfunded under SIGECO's Mortgage Indenture. SIGECO's gross utility plant balance subject to the Mortgage Indenture approximated $3.4 billion at December 31, 2017.

Consolidated maturities of long-term debt during the five years following 2017 (in millions) are $100 in 2018, $60 in 2019, $100 in 2020, $55 in 2021, $80 in 2022, and $1,444 thereafter.

Debt Guarantees

Vectren Corporation guarantees Vectren Capital's debt, but does not guarantee Utility Holdings' debt. Vectren Capital's long-term debt outstanding at December 31, 2017 was $260 million. Vectren Capital had $70 million short-term obligations outstanding at December 31, 2017. Utility Holdings' outstanding long-term and short-term borrowing arrangements are jointly and severally guaranteed by its wholly owned subsidiaries and regulated utilities Indiana Gas, SIGECO, and VEDO. Utility Holdings' long-term debt and short-term obligations outstanding at December 31, 2017 approximated $1.2 billion and $180 million, respectively.

Covenants

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 December 31, 2017, the Company was in compliance with all debt covenants.

Short-Term Borrowings

On July 14, 2017, Utility Holdings closed on renegotiated credit agreements with existing lenders. These credit agreements mature on July 14, 2022 and replaced bank credit agreements that had an original maturity date of October 31, 2019. Utility Holdings' new credit facility totals $400 million with a $10 million swing line sublimit and a $20 million letter of credit sublimit. The Utility Holdings credit agreement is jointly and severally guaranteed by its wholly owned subsidiaries Indiana Gas, SIGECO, and VEDO and is a backup facility for Utility Holdings' commercial paper program. Vectren Capital's new credit facility totals $200 million with a $40 million swing line sublimit and a $80 million letter of credit sublimit. The Vectren Capital credit agreement funds the short-term borrowing needs of the Company's corporate and nonutility operations and is guaranteed by Vectren Corporation.

The total $600 million of short-term borrowing capacity between the two lines remains unchanged; however, the Utility Holdings credit agreement commitment was increased by $50 million as compared to the prior credit agreement, and the Vectren Capital credit agreement commitment was decreased by $50 million as compared to the prior credit agreement.

As reduced by borrowings currently outstanding, approximately $220 million was available for the Utility Group operations and $130 million was available for the wholly owned Nonutility Group and corporate operations at December 31, 2017.

The Company has historically funded the short-term borrowing needs of Utility Holdings' operations through the commercial paper market but maintains the ability to use the Utility Holdings' short-term borrowing facility when necessary. Throughout the years presented, Utility Holdings has successfully placed commercial paper as needed. Following is certain information regarding these short-term borrowing arrangements:

	Utility Group Borrowings			Nonutility Group Borrowings		
(In millions)	2017	2016	2015	2017	2016	2015
As of Year End						
Balance Outstanding	$179.5	$194.4	$ 14.5	$70.0	$ —	$ —
Weighted Average Interest Rate	1.92%	1.05%	0.55%	2.68%	N/A	N/A
Annual Average						
Balance Outstanding	$172.4	$ 59.8	$ 53.8	$12.2	$ 0.2	$24.8
Weighted Average Interest Rate	1.30%	0.71%	0.38%	2.44%	1.60%	1.33%
Maximum Month End Balance Outstanding	$238.7	$194.4	$121.5	$70.0	$ 6.3	$69.1

11. Common Shareholders' Equity

Authorized, Reserved Common and Preferred Shares

At December 31, 2017 and 2016, the Company was authorized to issue 480 million shares of common stock and 20 million shares of preferred stock. Of the authorized common shares, approximately 4.6 million shares at December 31, 2017 and 2016 were reserved by the board of directors for issuance through the Company's share-based compensation plans, benefit plans, and dividend reinvestment plan. At December 31, 2017 and 2016, there were 392.4 million and 392.5 million, respectively, of authorized shares of common stock and all authorized shares of preferred stock, available for a variety of general corporate purposes, including future public offerings to raise additional capital.

12. Earnings Per Share

The Company uses the two class method to calculate earnings per share (EPS). The two class method is an earnings allocation formula that treats a participating security as having rights to earnings that otherwise would have been available to common shareholders. Under the two class method, earnings for a period are allocated between common shareholders and participating security holders based on their respective rights to receive dividends as if all undistributed book earnings for the period were distributed. The amount of net income attributable to participating securities is immaterial.

Basic EPS is computed by dividing net income attributable to only the common shareholders by the weighted-average number of common shares outstanding for the period. Diluted EPS includes the impact of stock options and other equity based instruments to the extent the effect is dilutive.

The following table illustrates the basic and dilutive EPS calculations for the three years ended December 31, 2017:

	Year Ended December 31,		
(In millions, except per share data)	2017	2016	2015
Numerator:			
Reported net income (Numerator for Basic and Diluted EPS)	$216.0	$211.6	$197.3
Denominator:			
Weighted-average common shares outstanding (Basic and Diluted EPS)	83.0	82.8	82.7
Basic and diluted earnings per share	**$ 2.60**	**$ 2.55**	**$ 2.39**

For the periods presented, all equity based instruments were dilutive and immaterial.

13. Accumulated Other Comprehensive Income

A summary of the components of and changes in *Accumulated other comprehensive income* for the past three years follows:

	2015			2016		2017	
(In millions)	Beginning of Year Balance	Changes During Year	End of Year Balance	Changes During Year	End of Year Balance	Changes During Year	End of Year Balance
Pension & other benefit costs	$ (2.2)	$ 0.1	$ (2.1)	$ (0.1)	$ (2.2)	$ —	$ (2.2)
Deferred income taxes	0.9	—	0.9	—	0.9	—	0.9
Accumulated other comprehensive income (loss)	**$ (1.3)**	**$ 0.1**	**$ (1.2)**	**$ (0.1)**	**$ (1.3)**	**$ —**	**$ (1.3)**

14. Share-Based Compensation & Deferred Compensation Arrangements

The Company has share-based compensation programs to encourage corporate and subsidiary officers, key non-officer employees, and non-employee directors to remain with the Company and to more closely align their interests with those of the Company's shareholders. Under these programs, the Company issues both performance-based and time-vested awards. All share-based compensation programs are shareholder approved. Currently, awards issued to a majority of the officers are performance-based, accrue dividends that are also subject to performance measures, and are settled in cash. In addition, the Company maintains a deferred compensation plan for officers and non-employee directors where participants can invest earned compensation and vested share-based awards in phantom Company stock units, among other options. Certain vesting grants provide for accelerated vesting if there is a change in control or upon the participant's retirement.

Following is a reconciliation of the total cost associated with share-based awards recognized in the Company's financial statements to its after tax effect on net income:

	Year Ended December 31,		
(In millions)	2017	2016	2015
Total cost of share-based compensation	$40.2	$30.0	$19.4
Less capitalized cost	8.6	7.0	4.8
Total in other operating expense	31.6	23.0	14.6
Less income tax benefit in earnings	12.3	9.0	5.7
After tax effect of share-based compensation	**$19.3**	**$14.0**	**$ 8.9**

Share-Based Awards & Other Awards

The vesting of awards issued to officers is contingent upon meeting total return and return on equity performance objectives. Grants to officers generally vest at the end of a three-year performance period. Based on performance objectives, the number of awards could double or could be entirely forfeited.

Non-employee directors receive a portion of their fees in share-based awards. These awards to non-employee directors are not performance-based and generally vest over one year. The majority of officers and non-employee directors must choose between either settling awards in cash or deferring awards into a deferred compensation plan (where the value is eventually withdrawn in cash). The number of such awards that may settle in shares, but are accounted for as liability awards due to their potential to be taken in cash when withdrawn from the deferred compensation plan, was approximately or less than 100,000 units as of December 31, 2017, 2016 and 2015.

Most officer, non-officer employee, and non-employee director awards are accounted for as liability awards at their settlement date fair value. The limited number of share awards to certain subsidiary officers that must be settled in shares are accounted for in equity at their grant date fair value.

A summary of the status of awards separated between those accounted for as liabilities and equity as of December 31, 2017 and 2016, and changes during the years ended December 31, 2017 and 2016, follow:

	Equity Awards		Liability Awards	
	Units	Wtd. Avg. Grant Date Fair value	Units	Fair value
Awards at January 1, 2016	15,373	$ 31.63	646,487	
Granted	4,052	30.19	448,176	
Vested	(11,711)	30.19	(462,203)	
Forfeited	(1,382)	31.87	(20,880)	
Awards at December 31, 2016	6,332	$ 33.42	611,580	$ 52.15
Granted	1,779	36.29	385,776	
Vested	(7,648)	33.25	(395,452)	
Forfeited	—	—	(8,364)	
Awards at December 31, 2017	**463**	**$ 46.21**	**593,540**	**$ 65.02**

As of December 31, 2017, there was $14.2 million of total unrecognized compensation cost associated with outstanding grants. That cost is expected to be recognized over a weighted-average period of 1.1 years. The total fair value of shares vested for liability awards during the years ended December 31, 2017, 2016, and 2015 was $25.1 million, $23.7 million, and $16.6 million, respectively. The total fair value of equity awards vesting during the years ended December 31, 2017, 2016, and 2015 was $0.5 million, $0.6 million, $1.1 million, respectively.

Deferred Compensation Plans

The Company has nonqualified deferred compensation plans, which permit eligible officers and non-employee directors to defer portions of their compensation and vested share-based compensation. A record keeping account is established for each participant, and the participant chooses from a variety of measurement funds for the deemed investment of their accounts. The measurement funds are similar to the funds in the Company's corporate defined contribution plan and include an investment in phantom stock units of the Company. The account balance fluctuates with the investment returns on those funds. The liability associated with these plans totaled $61.4 million and $40.9 million at December 31, 2017 and 2016 respectively. Other than $1.2 million and $0.9 million which is classified in *Accrued liabilities* at December 31, 2017 and 2016, respectively, the liability is included in *Deferred credits & other liabilities*. The impact of these plans on *Other operating* expenses was expense of $13.1 million in 2017, $4.3 million in 2016 and $0.1 million in 2015. The amount recorded in earnings related to the investment activities in Vectren phantom stock associated with these plans during the years ended December 31, 2017, 2016, and 2015, was expense of $10.1 million, expense of $3.8 million, and income of $0.4 million, respectively.

The Company has certain investments currently funded primarily through corporate-owned life insurance policies. These investments, which are consolidated, are available to pay deferred compensation benefits. These investments are also subject to the claims of the Company's creditors. The cash surrender value of these policies included in *Other corporate & utility investments* on the *Consolidated Balance Sheets* were $42.2 million and $33.1 million at December 31, 2017 and 2016, respectively. Those investments generated earnings of $5.9 million in 2017, earnings of $3.5 million in 2016, and losses of $2.1 million in 2015. This activity is reflected in *Other operating expenses.*

15. Commitments & Contingencies

Commitments

Future minimum lease payments required under operating leases that have initial or remaining noncancelable lease terms in excess of one year during the five years following 2017 and thereafter (in millions) are $14.2 in 2018, $10.1 in 2019, $4.9 in 2020, $2.7 in 2021, $2.3 in 2022, and $5.8 thereafter. Total lease expense, for these type of commitments, (in millions) was $16.5 in 2017, $13.0 in 2016, and $11.1 in 2015.

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, coal, and electricity, 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.

Performance Guarantees & Product Warranties

In the normal course of business, wholly owned subsidiaries, such as Energy Systems Group, LLC (ESG), a subsidiary of the Energy Services operating segment, issue payment and performance bonds and other forms of assurance that commit them to timely install infrastructure, operate facilities, pay vendors and subcontractors, and support warranty obligations.

Specific to ESG's role as a general contractor in the performance contracting industry, at December 31, 2017, there are 66 open surety bonds supporting future performance. The average face amount of these obligations is $9.8 million, and the largest obligation has a face amount of $75.9 million. The maximum exposure from these obligations is limited to the level of uncompleted work and further limited by bonds issued to ESG by various contractors. At December 31, 2017, approximately 29 percent of work was yet to be completed on projects with open surety bonds. A significant portion of these open surety bonds will be released within one year. In instances where ESG operates facilities, project guarantees extend over a longer period. In addition to its performance obligations, ESG also warrants the functionality of certain installed infrastructure generally for one year and the associated energy savings over a specified number of years.

Based on a history of meeting performance obligations and installed products operating effectively, no liability or cost has been recognized for the periods presented as the Company assesses the likelihood of loss as remote. Since inception, ESG has paid a de minimis amount on energy savings guarantees.

Corporate Guarantees & Other Support

The Company issues parent level guarantees to certain vendors and customers of its wholly owned subsidiaries. These guarantees do not represent incremental consolidated obligations; but rather, represent guarantees of subsidiary obligations in order to allow those subsidiaries the flexibility to conduct business without posting other forms of collateral. At December 31, 2017, parent level guarantees support a maximum of $373 million of ESG's performance contracting commitments, warranty obligations, project guarantees, and energy savings guarantees. Given the infrequent occurrence of any performance shortfalls historically on any of these commitments, no reserve for a potential liability has been deemed warranted.

Further, an energy facility operated by ESG and managed by Keenan Ft. Detrick Energy, LLC (Keenan), is governed by an operations agreement. Under this agreement, all payment obligations to Keenan are also guaranteed by the Company. The Company guarantee of the Keenan operations agreement does not state a maximum guarantee. Due to the nature of work performed under this contract, the Company cannot estimate a maximum potential amount of future payments but assesses the likelihood of loss as remote based on, primarily, the nature of the project.

The Company has not been called on to perform under these guarantees historically. While there can be no assurance that performance under these provisions will not be required in the future, the Company believes that the likelihood of a material amount being incurred under these provisions is remote given the nature of the projects, the manner in which the savings estimates are developed, and the fact that the value of the guarantees decrease over time as actual savings are achieved.

The Company from time to time, and primarily through Vectren Capital, issues letters of credit that support consolidated operations. At December 31, 2017, letters of credit outstanding total $36.3 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 position, results of operations or cash flows.

16. Gas Rate and 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 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 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.

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 December 31, 2017 and December 31, 2016, the Company has regulatory assets totaling $22.7 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 future 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 is now complete, 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. On April 27, 2017, the Indiana Court of Appeals affirmed the IURC Order. 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 additional Orders approving plan investments. 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. The plan increase, totaling $105 million since inception, is for additional investments related to pipeline safety and compliance requirements under Senate Bill 251.

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. The request includes approximately $15 million of operating expenses and $17 million of capital investments 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 December 31, 2017 and December 31, 2016, the Company has regulatory assets related to the Plan totaling $78.0 million and $51.1 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 total, the Company has made capital investments on projects that are now in-service under the DRR totaling $321.1 million as of December 31, 2017, of which $261.1 million has been approved for recovery under the DRR through December 31, 2016. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $31.2 million and $24.4 million at December 31, 2017 and December 31, 2016, respectively. In August 2017, the Company received approval to adjust the DRR rates, effective December 31, 2017, for recovery of costs incurred through December 31, 2016.

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 December 31, 2017 and December 31, 2016, the Company has regulatory assets totaling $66.1 million and $41.9 million, respectively, associated with the deferral of depreciation, post-in-service carrying costs, and property taxes. As of December 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.

Vectren Ohio Gas Rate Case

On February 21, 2018, the Company submitted a pre-filing notice with the PUCO indicating it plans to request an increase in its base rate charges for VEDO's distribution business in its 17 county service area in west-central Ohio. The filing is necessary 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. Also in the filing, the Company seeks approval for the continuation of the DRR mechanism. The Company will file the case-in-chief at the end of March 2018, and expects 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.

17. Electric Rate and 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. The filing requested the recovery of associated capital expenditures estimated to be approximately $500 million over the seven-year period beginning in 2017.

On September 20, 2017, the IURC issued an Order approving the settlement agreement reached between the Company, the OUCC and a coalition of industrial customers on May 18, 2017. The settlement agreement reduced the plan spend to $446 million, with defined annual caps on recoverable capital investments. The majority of the reduction relating to the removal of 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. In removing it from the plan, the request for cost recovery for the AMI project will not occur until the next base rate review proceeding, which would be expected to be filed by the end of 2023. 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 also addresses that semi-annual filings are to be made August 1, based on capital investments and expenses through the period ended April 30, and February 1, based on capital investments and expenses through October 31. The parties agreed in the settlement that the Company would make its first semi-annual filing on August 1, 2017, with additional time allotted subsequent to the plan case order for intervening parties to review the filing and to address any changes to the settlement agreement.

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 December 31, 2017, the Company has regulatory assets related to the Electric TDSIC plan totaling $4.3 million.

Renewable Generation Resources

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 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 approved cost of the projects cannot exceed the approximate $16 million estimate submitted by the Company, without seeking further Commission approval.

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 December 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 December 31, 2017, the Company has approximately $12.8 million deferred related to depreciation and operating expenses, and $4.7 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 Indiana Court of Appeals affirmed the IURC's June 22, 2016 Order.

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. No procedural schedule has been set, but the Company would expect an order in the first quarter of 2019.

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, 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 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. An appeal schedule has not been set, and 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. An appeal schedule has not been set, and 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 twelve months ended December 31, 2017, 2016, and 2015, the Company recognized electric utility revenue of $11.6 million, $11.1 million, and $10.1 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 December 31, 2017, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $133.5 million at December 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, 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 resource plans.

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 Integrated Resource Plan 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 Commission 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 CPCN authorizing construction timelines and costs of new generation resources, as well as necessary unit retrofits, to implement the generation transition process. In that filing, the Company seeks approval of its generation 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. The Company expects an order from the Commission in this proceeding by the first half of 2019.

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. The Company will seek authority from the IURC pursuant to Senate Bill 29 to recover the costs associated with the project.

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 preferred generation 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 strategy, 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.

18. Environmental and 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 plant 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's 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 2018 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, 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. 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.

Throughout 2016 and 2017, the Company has continued 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 preferred IRP. 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 December 31, 2017, 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 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. In September, 2015, the EPA finalized 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.

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 ELGs, which were approved by IDEM. 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 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 are included in the generation transition plan in Footnote 17 in the Company's Consolidated Financial Statements included in Item 8.

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 preferred generation 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.

<u>Air Quality</u>

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.

<u>Climate Change and Carbon Strategy</u>

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 CO2/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 are 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 are 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 is Unknown

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.

<u>Manufactured Gas Plants</u>

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 December 31, 2017 and December 31, 2016, approximately $2.5 million and $2.9 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

19. Fair Value Measurements

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

	At December 31,			
	2017		2016	
(In millions)	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	$1,838.7	$1,981.2	$1,714.0	$1,835.8
Short-term borrowings & notes payable	249.5	249.5	194.4	194.4
Cash & cash equivalents	16.6	16.6	68.6	68.6
Natural gas purchase instrument assets (1)	0.5	0.5	—	—
Natural gas purchase instrument liabilities (2)	4.5	4.5	—	—
Interest rate swap liabilities (3)	1.4	1.4	—	—
Restricted cash	—	—	0.9	0.9

(1) Presented in "Other utility & corporate investments" on the Consolidated Balance Sheets.
(2) Presented in "Deferred credits & other liabilities" on the Consolidated Balance Sheets.
(3) Presented in "Deferred credits & other liabilities" on the Consolidated Balance Sheets.

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 four five-year forward purchase arrangements to hedge the variable 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, as described in Note 10, 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.

Because of the nature of certain other investments and lack of a readily available market, it is not practical to estimate the fair value of these financial instruments at specific dates without considerable effort and cost. At December 31, 2017 and 2016, the fair value for these financial instruments was not estimated. The carrying value of these investments at December 31, 2017 and 2016 was approximately $9.6 million and $16.1 million, respectively.

20. Segment Reporting

The Company segregates its operations into three groups: 1) Utility Group, 2) Nonutility Group, and 3) Corporate and Other.

The Utility Group is comprised of Vectren Utility Holdings, Inc.'s operations, which consist of the Company's 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 Utility Group is comprised of three operating segments: Gas Utility Services, Electric Utility Services, and Other operations.

During the periods presented, the Nonutility Group had the following operating segments: Infrastructure Services, Energy Services, and Other Businesses. Energy Services, through the wholly owned subsidiary Energy Systems Group, LLC, provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects. The Infrastructure Services segment, through wholly owned subsidiaries Miller Pipeline, LLC and Minnesota Limited, LLC, provides underground pipeline construction and repair services for customers that include Vectren Utility Holdings' utilities. Fees incurred by Vectren Utility Holdings and its subsidiaries for these pipeline construction and repair services totaled $157.1 million in 2017, $117.8 million in 2016, and $109.5 million in 2015. The increase in 2017 is due to a large pipeline project that Minnesota Limited was awarded in a competitive process.

Corporate and Other includes unallocated corporate expenses such as advertising and certain charitable contributions, among other activities, that benefit the Company's other operating segments. Total assets in all periods presented reflect the retrospective impacts of the adoption in 2015 of ASU 2015-17, Balance Sheet Classification of Deferred Taxes and the retrospective impacts of the adoption in 2016 of ASU 2015-03, Presentation of Debt Issuance Costs. Net income is the measure of profitability used by management for all operations. Information related to the Company's business segments is summarized as follows:

(In millions)	Year Ended December 31, 2017	2016	2015
Revenues			
Utility Group			
Gas Utility Services	$ 812.7	$ 771.7	$ 792.6
Electric Utility Services	569.6	605.8	601.6
Other Operations	45.6	42.2	40.7
Eliminations	(45.3)	(41.9)	(40.4)
Total Utility Group	**1,382.6**	**1,377.8**	**1,394.5**
Nonutility Group			
Infrastructure Services	996.1	813.3	843.3
Energy Services	281.8	260.0	199.9
Total Nonutility Group	**1,277.9**	**1,073.3**	**1,043.2**
Eliminations, net of Corporate & Other Revenues	(3.2)	(2.8)	(3.0)
Consolidated Revenues	**$2,657.3**	**$2,448.3**	**$2,434.7**
Profitability Measures - Net Income			
Utility Group Net Income			
Gas Utility Services	$ 115.5	$ 76.1	$ 64.4
Electric Utility Services	75.2	84.7	82.6
Other Operations	(14.9)	12.8	13.9
Total Utility Group Net Income	**175.8**	**173.6**	**160.9**
Nonutility Group Net Income (Loss)			
Infrastructure Services	32.3	25.0	29.7
Energy Services	10.7	12.5	7.3
Other Businesses	(1.9)	(0.6)	(0.7)
Total Nonutility Group Net Income	**41.1**	**36.9**	**36.3**
Corporate & Other Net Income	(0.9)	1.1	0.1
Consolidated Net Income	**$ 216.0**	**$ 211.6**	**$ 197.3**

(In millions)	Year Ended December 31, 2017	2016	2015
Amounts Included in Profitability Measures			
Depreciation & Amortization			
Utility Group			
Gas Utility Services	$118.9	$108.1	$ 98.6
Electric Utility Services	89.5	87.1	85.6
Other Operations	26.1	23.9	24.6
Total Utility Group	**234.5**	**219.1**	**208.8**
Nonutility Group			
Infrastructure Services	39.7	38.2	44.5
Energy Services	1.9	2.5	2.7
Other Businesses	0.1	0.2	0.3
Total Nonutility Group	**41.7**	**40.9**	**47.5**
Consolidated Depreciation & Amortization	**$276.2**	**$260.0**	**$256.3**
Interest Expense			
Utility Group			
Gas Utility Services	$ 43.0	$ 40.1	$ 35.8
Electric Utility Services	25.8	27.0	27.8
Other Operations	3.8	2.6	2.7
Total Utility Group	**72.6**	**69.7**	**66.3**
Nonutility Group			
Infrastructure Services	13.8	12.8	16.0
Energy Services	0.6	1.9	1.2
Other Businesses	1.0	0.9	1.2
Total Nonutility Group	**15.4**	**15.6**	**18.4**
Corporate & Other	(0.3)	0.2	(0.2)
Consolidated Interest Expense	**$ 87.7**	**$ 85.5**	**$ 84.5**
Income Taxes			
Utility Group			
Gas Utility Services	$ 25.4	$ 47.1	$ 40.8
Electric Utility Services	41.4	50.1	49.3
Other Operations	(6.1)	2.3	(2.0)
Total Utility Group	**60.7**	**99.5**	**88.1**
Nonutility Group			
Infrastructure Services	(12.9)	17.9	19.6
Energy Services	(1.5)	(3.5)	(7.7)
Other Businesses	0.9	0.3	1.5
Total Nonutility Group	**(13.5)**	**14.7**	**13.4**
Corporate & Other	(0.8)	(1.3)	(1.8)
Consolidated Income Taxes	**$ 46.4**	**$112.9**	**$ 99.7**

(In millions)	Year Ended December 31, 2017	2016	2015
Capital Expenditures			
Utility Group			
Gas Utility Services	$ 391.4	$ 358.5	$ 291.2
Electric Utility Services	105.3	106.4	87.6
Other Operations	57.9	39.0	25.7
Non-cash costs & changes in accruals	(3.7)	(7.1)	(6.2)
Total Utility Group	**550.9**	**496.8**	**398.3**
Nonutility Group			
Infrastructure Services	48.4	43.2	78.1
Energy Services	3.2	1.8	0.5
Other Businesses, net of eliminations	0.1	0.2	—
Total Nonutility Group	**51.7**	**45.2**	**78.6**
Consolidated Capital Expenditures	**$ 602.6**	**$ 542.0**	**$ 476.9**

(In millions)	At December 31, 2017	2016	2015
Assets			
Utility Group			
Gas Utility Services	$3,457.8	$3,091.0	$2,706.9
Electric Utility Services	1,820.3	1,788.4	1,778.3
Other Operations, net of eliminations	220.1	161.5	107.5
Total Utility Group	**5,498.2**	**5,040.9**	**4,592.7**
Nonutility Group			
Infrastructure Services	552.6	513.9	554.5
Energy Services	155.8	182.7	160.3
Other Businesses, net of eliminations and reclassifications	59.1	53.3	64.0
Total Nonutility Group	**767.5**	**749.9**	**778.8**
Corporate & Other	449.1	628.4	742.4
Eliminations	(475.5)	(618.5)	(713.9)
Consolidated Assets	**$6,239.3**	**$5,800.7**	**$5,400.0**

21. Additional Balance Sheet & Operational Information

Inventories consist of the following:

(In millions)	At December 31, 2017	2016
Gas in storage – at LIFO cost	$ 36.0	$ 37.0
Coal & oil for electric generation - at average cost	43.1	42.6
Materials & supplies	46.2	48.9
Other	1.3	1.4
Total inventories	**$126.6**	**$129.9**

Based on the average cost of gas purchased during December, the cost of replacing inventories carried at LIFO cost is less than the carrying value at December 31, 2017 by $2.0 million. Based on the average cost of gas purchased during December, the cost of replacing inventories carried at LIFO cost exceeded carrying value at December 31, 2016 by $1.0 million.

Prepayments & other current assets consist of the following:

(In millions)	At December 31, 2017	2016
Prepaid gas delivery service	$26.6	$ 26.4
Prepaid taxes	3.8	8.2
Other prepayments & current assets	16.6	18.1
Total prepayments & other current assets	**$47.0**	**$ 52.7**

Investments in unconsolidated affiliates consist of the following:

(In millions)	At December 31, 2017	2016
ProLiance Holdings, LLC	$18.9	$ 19.2
Other nonutility partnerships & corporations	0.6	1.0
Other utility investments	0.2	0.2
Total investments in unconsolidated affiliates	**$19.7**	**$ 20.4**

Other utility & corporate investments consist of the following:

(In millions)	At December 31, 2017	2016
Cash surrender value of life insurance policies	$42.2	$ 33.1
Restricted cash & other investments	1.5	1.0
Total other utility & corporate investments	**$43.7**	**$ 34.1**

Goodwill by operating segment follows:

(In millions)	At December 31, 2017	2016
Utility Group		
Gas Utility Services	$205.0	$205.0
Nonutility Group		
Infrastructure Services	58.8	58.8
Energy Services	29.7	29.7
Consolidated goodwill	**$293.5**	**$293.5**

Accrued liabilities consist of the following:

(In millions)	At December 31, 2017	2016
Refunds to customers & customer deposits	$ 51.4	$ 49.4
Accrued taxes	55.7	46.5
Accrued interest	19.6	18.2
Deferred compensation & post retirement benefits	6.4	6.6
Accrued salaries & other	89.2	87.0
Total accrued liabilities	**$222.3**	**$207.7**

Asset retirement obligations included in *Deferred credits and other liabilities* in the Consolidated Balance Sheets roll forward as follows:

(In millions)	2017	2016
Asset retirement obligation, January 1	$106.7	$ 82.0
Accretion	4.3	3.8
Changes in estimates, net of cash payments	(4.0)	20.9
Asset retirement obligation, December 31	**$107.0**	**$106.7**

Equity in earnings (losses) of unconsolidated affiliates consists of the following:

	Year Ended December 31,		
(In millions)	2017	2016	2015
ProLiance Holdings, LLC	$(0.3)	$(0.5)	$(0.8)
Other	(0.8)	0.3	0.2
Total equity in earnings (losses) of unconsolidated affiliates	**$(1.1)**	**$(0.2)**	**$(0.6)**

Other income (expense) – net consists of the following:

	Year Ended December 31,		
(In millions)	2017	2016	2015
AFUDC – borrowed funds	$24.8	$20.3	$16.3
AFUDC – equity funds	2.6	2.2	2.6
Nonutility plant capitalized interest	1.2	1.0	0.4
Interest income, net	1.0	1.3	1.3
Other nonutility investment impairment charges	—	—	(0.1)
All other income	3.2	3.9	(0.2)
Total other income – net	**$32.8**	**$28.7**	**$20.3**

Supplemental Cash Flow Information:

	Year Ended December 31,		
(In millions)	2017	2016	2015
Cash paid (received) for:			
Interest	$86.4	$86.6	$84.2
Income taxes	9.6	(3.6)	4.8

As of December 31, 2017 and 2016, the Company has accruals related to utility and nonutility plant purchases totaling approximately $28.6 million and $30.0 million, respectively.

22. Impact of Recently Issued Accounting Guidance

Revenue Recognition

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 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). The Company plans to adopt the guidance under the modified retrospective method. The cumulative effect adjustment to retained earnings will be immaterial.

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 has finalized the assessment process of all revenue streams for the standard's impact on the Consolidated Balance Sheets, Consolidated Statements of Operations, and disclosures and has identified all material revenue streams. The Company has determined that all material revenue streams fall under the scope of the standard. The standard will result in no significant changes to the Company's pattern of revenue recognition. The Company has adopted 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 and will adopt the guidance effective January 1, 2019.

Stock Compensation

In March 2016, the FASB issued new accounting guidance intended to simplify several aspects of accounting for share-based payment transactions, including the income tax consequences. This ASU was effective for annual periods beginning after December 15, 2016, and interim periods therein. Most of the Company's share-based awards are settled via cash payments and were 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. This ASU requires the Company to report the service cost component 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. Capitalization of net benefit cost is limited to only the service cost component of benefit costs, when applicable.

The ASU requires retrospective presentation of the service and non-service costs components in the income statement and prospective application regarding the capitalization of only the service cost component of net benefit costs. The Company has finalized its assessment of the standard and the adoption will have an immaterial impact on the financial statements. The Company has adopted 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.

23. Quarterly Financial Data (Unaudited)

Information in any one quarterly period is not indicative of annual results due to the seasonal variations common to the Company's utility operations. Summarized quarterly financial data for 2017 and 2016 follows:

(In millions, except per share amounts)	Q1	Q2	Q3	Q4
2017				
Operating revenues	$624.5	$630.7	$691.2	$711.0
Operating income	101.4	72.8	107.5	36.8
Net income	55.4	37.6	61.9	61.2
Earnings per share:				
Basic and Diluted	$ 0.67	$ 0.45	$ 0.75	$ 0.74
2016				
Operating revenues	$584.8	$533.7	$631.0	$699.0
Operating income	92.2	63.9	105.5	120.7
Net income	48.3	32.3	61.4	69.6
Earnings per share:				
Basic and Diluted	$ 0.58	$ 0.39	$ 0.74	$ 0.84

SCHEDULE II
Vectren Corporation and Subsidiaries
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C Additions		Column D	Column E
Description *(In millions)*	Balance at Beginning of Year	Charged to Expenses	Charged to Other Accounts	Deductions from Reserves, Net	Balance at End of Year
VALUATION AND QUALIFYING ACCOUNTS:					
Year 2017 – Accumulated provision for uncollectible accounts	$ 6.0	$ 5.9	$ —	$ 6.8	$ 5.1
Year 2016 – Accumulated provision for uncollectible accounts	$ 5.6	$ 6.9	$ —	$ 6.5	$ 6.0
Year 2015 – Accumulated provision for uncollectible accounts	$ 6.0	$ 8.1	$ —	$ 8.5	$ 5.6
Year 2017 – Reserve for impaired notes receivable	$ 0.6	$ 0.4	$ —	$ —	$ 1.0
Year 2016 – Reserve for impaired notes receivable	$ 0.2	$ 0.4	$ —	$ —	$ 0.6
Year 2015 – Reserve for impaired notes receivable	$ —	$ 0.2	$ —	$ —	$ 0.2

Exhibit 99.2

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited – In millions)

	June 30, 2018	December 31, 2017
ASSETS		
Current Assets		
Cash & cash equivalents	$ 9.8	$ 16.6
Accounts receivable - less reserves of $5.8 & $5.1, respectively	232.0	262.9
Accrued unbilled revenues	148.1	207.1
Inventories	103.7	126.6
Recoverable fuel & natural gas costs	9.7	19.2
Prepayments & other current assets	43.1	47.0
Total current assets	**546.4**	**679.4**
Utility Plant		
Original cost	7,260.3	7,015.4
Less: accumulated depreciation & amortization	2,816.3	2,738.7
Net utility plant	**4,444.0**	**4,276.7**
Investments in unconsolidated affiliates	1.8	19.7
Other utility & corporate investments	45.1	43.7
Other nonutility investments	9.6	9.6
Nonutility plant - net	479.4	464.1
Goodwill	293.5	293.5
Regulatory assets	441.3	416.8
Other assets	35.0	35.8
TOTAL ASSETS	**$6,296.1**	**$ 6,239.3**

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

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited – In millions)

	June 30, 2018	December 31, 2017
LIABILITIES & SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 225.0	$ 366.2
Accrued liabilities	231.3	222.3
Short-term borrowings	247.9	249.5
Current maturities of long-term debt	60.0	100.0
Total current liabilities	**764.2**	**938.0**
Long-term Debt - Net of Current Maturities	1,928.7	1,738.7
Deferred Credits & Other Liabilities		
Deferred income taxes	501.1	491.3
Regulatory liabilities	943.1	937.2
Deferred credits & other liabilities	297.2	284.8
Total deferred credits & other liabilities	**1,741.4**	**1,713.3**
Commitments & Contingencies (Notes 8, 11-14)		
Common Shareholders' Equity		
Common stock (no par value) – issued & outstanding 83.1 & 83.0, respectively	739.5	736.9
Retained earnings	1,123.6	1,113.7
Accumulated other comprehensive (loss)	(1.3)	(1.3)
Total common shareholders' equity	**1,861.8**	**1,849.3**
TOTAL LIABILITIES & SHAREHOLDERS' EQUITY	**$6,296.1**	**$ 6,239.3**

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

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited – In millions, except per share amounts)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
OPERATING REVENUES				
Gas utility	$149.3	$ 144.0	$ 478.6	$ 436.8
Electric utility	143.3	141.8	277.4	273.8
Nonutility	351.7	344.9	546.8	544.5
Total operating revenues	**644.3**	**630.7**	**1,302.8**	**1,255.1**
OPERATING EXPENSES				
Cost of gas sold	41.6	37.2	186.8	150.1
Cost of fuel & purchased power	47.8	43.6	90.1	84.7
Cost of nonutility revenues	111.6	120.4	178.4	182.2
Other operating	284.6	273.3	513.1	497.6
Merger-related	15.3	—	15.3	—
Depreciation & amortization	72.4	68.3	143.8	136.1
Taxes other than income taxes	15.5	13.9	35.4	29.1
Total operating expenses	**588.8**	**556.7**	**1,162.9**	**1,079.8**
OPERATING INCOME	**55.5**	**74.0**	**139.9**	**175.3**
OTHER INCOME (EXPENSE)				
Equity in (losses) of unconsolidated affiliates	(17.8)	(0.3)	(17.9)	(0.8)
Other income – net	10.0	7.1	18.9	15.1
Total other income (expense)	(7.8)	6.8	1.0	14.3
INTEREST EXPENSE	24.0	21.4	47.5	42.7
INCOME BEFORE INCOME TAXES	**23.7**	**59.4**	**93.4**	**146.9**
INCOME TAXES	1.5	21.8	7.7	54.0
NET INCOME AND COMPREHENSIVE INCOME	**$ 22.2**	**$ 37.6**	**$ 85.7**	**$ 92.9**
WEIGHTED AVERAGE AND DILUTED COMMON SHARES OUTSTANDING	**83.1**	**82.9**	**83.1**	**82.9**
BASIC AND DILUTED EARNINGS PER SHARE OF COMMON STOCK	**$ 0.27**	**$ 0.45**	**$ 1.03**	**$ 1.12**
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	**$ 0.45**	**$ 0.42**	**$ 0.90**	**$ 0.84**

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

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited – In millions)

	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 85.7	$ 92.9
Adjustments to reconcile net income to cash from operating activities:		
Depreciation & amortization	143.8	136.1
Deferred income taxes & investment tax credits	(3.6)	53.4
Provision for uncollectible accounts	4.4	3.1
Expense portion of pension & postretirement benefit cost	2.2	3.4
Other non-cash items - net	18.3	5.5
Changes in working capital accounts:		
Accounts receivable & accrued unbilled revenues	85.5	53.9
Inventories	22.9	11.3
Recoverable/refundable fuel & natural gas costs	9.5	(2.2)
Prepayments & other current assets	4.1	(3.8)
Accounts payable	(149.9)	(69.9)
Accrued liabilities	9.9	(6.4)
Employer contributions to pension & postretirement plans	(5.6)	(2.2)
Changes in noncurrent assets	(7.3)	(13.5)
Changes in noncurrent liabilities	(1.5)	(9.8)
Net cash from operating activities	**218.4**	**251.8**
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from:		
Long-term debt, net of issuance costs	(0.6)	—
Dividend reinvestment plan & other common stock issuances	1.7	3.1
Requirements for dividends on common stock	(74.8)	(69.6)
Net change in short-term borrowings	148.4	51.8
Net cash from financing activities	**74.7**	**(14.7)**
CASH FLOWS FROM INVESTING ACTIVITIES		
Proceeds from sale of assets and other collections	5.4	1.3
Requirements for:		
Capital expenditures, excluding AFUDC equity	(305.3)	(293.5)
Other costs	—	(3.4)
Changes in restricted cash	—	0.9
Net cash from investing activities	**(299.9)**	**(294.7)**
Net change in cash & cash equivalents	(6.8)	(57.6)
Cash & cash equivalents at beginning of period	16.6	68.6
Cash & cash equivalents at end of period	$ 9.8	$ 11.0

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

1. Organization and Nature of Operations

Vectren Corporation (the Company or Vectren), an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana. The Company's wholly owned subsidiary, Vectren Utility Holdings, Inc. (Utility Holdings or VUHI), serves as the intermediate holding company for three public utilities: Indiana Gas Company, Inc. (Indiana Gas or Vectren Energy Delivery of Indiana - North), Southern Indiana Gas and Electric Company (SIGECO or Vectren Energy Delivery of Indiana - South), and Vectren Energy Delivery of Ohio, Inc. (VEDO). Utility Holdings also has other assets that provide information technology and other services to the three utilities. Utility Holdings' consolidated operations are collectively referred to as the Utility Group. Both Vectren and Utility Holdings are holding companies as defined by the Energy Policy Act of 2005. Vectren was incorporated under the laws of Indiana on June 10, 1999.

Indiana Gas provides energy delivery services to approximately 601,000 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 321,000 natural gas customers located near Dayton in west-central Ohio.

The Company, through Vectren Enterprises, Inc. (Enterprises), is involved in nonutility activities in two primary business areas: Infrastructure Services and Energy Services. Infrastructure Services provides underground pipeline construction and repair services. Energy Services provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects. Enterprises also has other legacy businesses that have investments in energy-related opportunities and services and other investments. All of the above is collectively referred to as the Nonutility Group. Enterprises supports the Company's regulated utilities by providing infrastructure services.

Merger with CenterPoint Energy, Inc.

On April 21, 2018, the Company 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 the Company (the "Merger"), with the Company 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 the Company shall be converted into the right to receive $72.00 in cash without interest.

The Company, CenterPoint and Merger Sub each have made various representations, warranties and covenants in the Merger Agreement. Among other things, the Company 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. The Company has made certain additional customary covenants, including, subject to certain exceptions: (1) to cause a meeting of the Company'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 shareholders regarding the Merger. In addition, subject to the terms of the Merger Agreement, the Company, 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 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 have been made with each commission.

Consummation of the Merger is subject to various conditions, including: (1) approval of the shareholders of the Company, (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 the Company and its subsidiaries.

The Merger Agreement contains certain termination rights for both the Company 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 the Company 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 the Company, and under other specified circumstances the Company would be required to pay CenterPoint a termination fee of $150 million.

On June 15, 2018, Vectren and CenterPoint submitted their filings with the Federal Energy Regulatory Commission and initiated informational proceedings with regulators in Indiana and Ohio. The IURC has set a schedule for the review of information that has been voluntarily submitted by the companies regarding the merger that includes an October 17, 2018 hearing. Further, on June 18, 2018, Vectren and CenterPoint submitted their filings pursuant to the Hart-Scott-Rodino Act and the Federal Communications Commission. On June 26, 2018, CenterPoint and Vectren received notice from the Federal Trade Commission granting early termination of the waiting period under the Hart-Scott-Rodino Act. On July 16, 2018, the Company filed a definitive proxy statement, and a Form 8-K including supplemental disclosures to the proxy statement, with the Securities and Exchange Commission in connection with the Merger. On July 24, 2018, the Federal Communications Commission provided the final approvals for the transfer of control of the Company's subsidiaries which hold radio licenses. As of August 2, 2018, seven purported Company shareholders have filed lawsuits under the federal securities laws in the United States District Court for the Southern District of Indiana challenging the adequacy of the disclosures made in the Company's proxy statement in connection with the merger as discussed in Note 11. A special shareholders meeting to vote on matters relating to the proposed merger is scheduled for August 28, 2018. Subject to receipt of remaining approvals, the Company continues to anticipate that the closing of the merger will occur no later than the first quarter of 2019.

In connection with this transaction, the Company recorded merger-related expenses of $15.3 million in the quarter ending June 30, 2018, which are reflected in *Merger-related* in *Operating Expenses* in the Condensed Consolidated Statements of Income. Merger-related expenses for the quarter include $10.2 million of transaction advisory and other costs and $5.1 million for the end of period measurement of share-based and deferred compensation obligations that resulted from increases in the Company's common stock trading price since the announcement of the Merger. The Company has treated these costs as tax deductible since the requisite closing conditions to the Merger have not yet been satisfied. Upon completion of the Merger, the Company will evaluate the tax deductibility of these costs and, though not expected, will reflect any non-deductible amounts in the effective tax rate at the Merger closing date.

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 February 21, 2018, on Form 10-K. Because of the seasonal nature of the Company's 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 a cumulative effect reduction of $1.1 million 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.

The cumulative effect recorded resulted from a change in the accounting for revenue associated with certain specialized equipment used on projects in the Energy Services segment of the Nonutility Group, where under the new revenue standard, recognition is proportionate to progress in satisfying the performance obligation, and previously was recognized when the equipment was procured.

The cumulative effect of the changes made to the Company's consolidated January 1, 2018 balance sheet for the adoption of the new revenue standard is as follows:

Balance Sheet *(In millions)*	Balance at December 31, 2017	Adjustments due to ASC 606	Balance at January 1, 2018
Assets			
Accrued unbilled revenues	$ 207.1	$ (7.0)	$ 200.1
Prepayments and other current assets	47.0	5.6	52.6
Liabilities			
Accrued liabilities	222.3	(0.3)	222.0
Common Shareholders' Equity			
Retained earnings	$ 1,113.7	$ (1.1)	$ 1,112.6

The adoption of the new revenue standard had an immaterial impact to the Condensed Consolidated Income Statements for the three and the six month periods ended June 30, 2018 and the Condensed Consolidated Balance Sheet as of June 30, 2018, increasing net income by less than $1 million. The impact was also a result of the change in revenue recognition on specialized equipment.

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 these categories achieves the disclosure objective to depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors. These material revenue generating categories, as disclosed in Note 17, include: Gas Utility Services, Electric Utility Services, Infrastructure Services, and Energy Services.

Utility Group (Gas Utility Services and Electric Utility Services)

The Utility Group 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 Utility Group's revenues are not subject to significant returns, refunds, or warranty obligations.

In the following table, Utility Group revenue is disaggregated by customer class.

(In millions)	Three Months Ended June 30, 2018	Six Months Ended June 30, 2018
Gas Utility Services		
Residential	$ 100.3	$ 320.0
Commercial	30.2	112.7
Industrial	16.7	40.5
Other	2.1	5.4
Total Gas Utility Services	$ 149.3	$ 478.6
Electric Utility Services		
Residential	$ 50.7	$ 100.4
Commercial	37.3	71.8
Industrial	41.1	78.4
Other	14.2	26.8
Total Electric Utility Services	$ 143.3	$ 277.4

Infrastructure Services

Infrastructure Services provides underground pipeline construction and repair services. The duration of the contracts are generally less than one year and consist of fixed price, unit, and time and material customer contracts. Under unit or time and material contracts, the Company performs construction and repair services under specific work-orders at prices established by master service agreements. The performance obligation is defined at the work-order level. These services are billed to customers monthly or more frequently for work completed based on units completed or time and material cost incurred, and generally require payment within 30 days of billing. The Company has the right to consideration from customers in an amount that corresponds directly with the performance obligation satisfied, and therefore recognizes revenue at a point in time in the amount to which it has the right to invoice, which results in *Accrued unbilled revenues* at the end of each accounting period. Under fixed price contracts, the Company performs larger scale construction and repair services. Each contract is typically viewed as a single performance obligation. Services performed under fixed price contracts are typically billed per the terms of the contract, which can range from completion of specific milestones or scheduled billing intervals. Billings occur monthly or more frequently for work completed, and generally require payment within 30 days of billing. Revenue for fixed price contracts are recognized over time as control is transferred using the input method, considering costs incurred relative to total expected cost. Total expected cost is therefore a significant judgment affecting the amount and timing of revenue recognition. Infrastructure Services' revenues are not subject to significant returns, refunds, or warranty obligations.

The following table disaggregates Infrastructure Services revenue by type of contract and timing of transfer of control:

(In millions)	Three Months Ended June 30, 2018	Six Months Ended June 30, 2018
Revenue		
Unit or time and material (point in time)	$ 159.4	$ 283.8
Fixed price (over time)	120.0	130.9
Total Infrastructure Services	$ 279.4	$ 414.7

Energy Services

Energy Services provides energy performance contracting and sustainable infrastructure services. While a majority of Energy Services' revenues are from construction services, some customer contracts also include operation and maintenance services. The performance obligations are distinct as the customer can realize benefits from the construction services without the operation and maintenance services. The prices of each performance obligation are specifically stated in the contract and have been developed independently. Billing methods can vary. Most construction performance obligations require an initial deposit and are either billed monthly for progress completed or according to a contractual draw schedule, which results in *Accrued Unbilled Revenues* at the end of each accounting period. Payments are typically required within 30 days of billing. Revenues on construction performance obligations, which may have durations greater than one year, are recognized over time as control is transferred using the input method, considering costs incurred relative to total expected cost. Total expected cost is therefore a significant judgment affecting the amount and timing of revenue recognition. Revenue on operations and maintenance performance obligations are recognized ratably over the life of the contract. Energy Services' contracts may be subject to performance guarantees and product warranties as discussed in Note 11.

The following table disaggregates Energy Services revenue by type of performance obligation:

(In millions)	Three Months Ended June 30, 2018	Six Months Ended June 30, 2018
Revenue		
Construction	$ 66.9	$ 120.7
Operations and maintenance and other	6.9	13.7
Total Energy Services	$ 73.8	$ 134.4

Nonutility Contract Balances

When the timing of the Company's delivery of nonutility service is different from the timing of the payments made by customers and when the right to consideration is conditioned on something other than the passage of time, the Company recognizes either a contract asset (performance precedes billing) or a contract liability (customer payment precedes performance). Those customers that prepay are represented by contract liabilities until the performance obligations are satisfied. The Company's contract liabilities are included in *Accrued Liabilities* in the Condensed Consolidated Balance Sheets. The Company's contract liabilities primarily relate to contracts in the Energy Services segments where revenue is recognized using the input method. The Company did not have contract assets as of January 1, 2018 or June 30, 2018.

The opening and closing balances of the Company's accounts receivable, accrued unbilled revenue, and contract liabilities are as follows:

(In millions)	Accounts Receivable	Accrued Unbilled Revenues	Contract Liabilities
Opening (01/01/2018)	$ 262.9	$ 200.1	$ 38.3
Closing (06/30/2018)	232.0	148.1	32.1
Increase/(decrease)	$ (30.9)	$ (52.0)	$ (6.2)

The amount of revenue recognized in the six month period ending June 30, 2018 that was included in the opening contract liability was $37.1 million. The difference between the opening and closing balances of the company's contract liabilities primarily results from the timing difference between the Company's performance and the customer's payment.

Remaining Performance Obligations

The table below discloses (1) the aggregate amount of the transaction price allocated to performance obligations that are unsatisfied (or partially unsatisfied) as of the end of the reporting period for contracts and (2) when the company expects to recognize this revenue. Such contracts include both construction and operations and maintenance performance obligations from the Energy Services segment and fixed price contracts in the Infrastructure Services segment.

(In millions)	Rolling 12 Months	Thereafter	Total
Revenue expected to be recognized on contracts in place as of June 30, 2018:			
Energy Services - operations and maintenance	$ 28.4	$ 399.0	$427.4
Energy Services - construction	171.3	24.5	195.8
Infrastructure Services - fixed price (bid)	200.6	—	200.6
Total	$ 400.3	$ 423.5	$823.8

For the Company's contracts for which revenue from the satisfaction of the performance obligations is recognized in the amount invoiced, the Company elected the simplified option available in the standard, known as practical expedient, and has not disclosed the revenue expected to be recognized on these contracts.

4. Earnings Per Share

The Company uses the two-class method to calculate earnings per share (EPS). The two-class method is an earnings allocation formula that treats a participating security as having rights to earnings that otherwise would have been available to common shareholders. Under the two-class method, earnings for a period are allocated between common shareholders and participating security holders based on their respective rights to receive dividends as if all undistributed book earnings for the period were distributed. The amount of net income attributable to participating securities is immaterial.

Basic EPS is computed by dividing net income attributable to only the common shareholders by the weighted-average number of common shares outstanding for the period. Diluted EPS includes the impact of share-based compensation to the extent the effect is dilutive.

The following table illustrates the basic and dilutive EPS calculations for the periods presented in these financial statements.

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions, except per share data)	2018	2017	2018	2017
Numerator:				
Reported net income (Numerator for Basic and Diluted EPS)	$ 22.2	$ 37.6	$ 85.7	$ 92.9
Denominator:				
Weighted-average common shares outstanding (Denominator for Basic and Diluted EPS)	83.1	82.9	83.1	82.9
Basic and Diluted EPS	**$ 0.27**	**$ 0.45**	**$ 1.03**	**$ 1.12**

For the three and six months ended June 30, 2018 and 2017, all equity based instruments were dilutive and immaterial.

5. Excise & 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 $6.3 million and $5.5 million in the three months ended June 30, 2018 and 2017, respectively, as a component of operating revenues. During the six months ended June 30, 2018 and 2017, these taxes totaled $16.8 million and $14.9 million, respectively. Expenses associated with excise and utility receipts taxes are recorded as a component of *Taxes other than income taxes*.

6. Retirement Plans & Other Postretirement Benefits

The Company maintains three closed qualified defined benefit pension plans, a nonqualified supplemental executive retirement plan (SERP), and a postretirement benefit plan. The defined benefit pension plans and postretirement benefit plan, which cover eligible full-time regular employees, are primarily noncontributory. The postretirement benefit plan includes health care and life insurance benefits which are a combination of self-insured and fully insured plans. The qualified pension plans and the SERP are aggregated under the heading "Pension Benefits." The postretirement benefit plan is presented under the heading "Other Benefits."

Net Periodic Benefit Costs

A summary of the components of net periodic benefit cost follows and the amortizations shown below are primarily reflected in *Regulatory assets* as a majority of pension and other postretirement benefits are being recovered through rates.

	Three Months Ended June 30,			
	Pension Benefits		Other Benefits	
(In millions)	2018	2017	2018	2017
Service cost	$ 1.7	$ 1.6	$ 0.1	$ 0.1
Interest cost	3.2	3.4	0.4	0.4
Expected return on plan assets	(5.3)	(5.2)	—	—
Amortization of prior service cost	0.1	0.1	(0.6)	(0.6)
Amortization of actuarial loss	2.1	1.8	—	—
Settlement charge	—	1.9	—	—
Net periodic cost (benefit)	**$ 1.8**	**$ 3.6**	**$(0.1)**	**$(0.1)**

	Six Months Ended June 30,			
	Pension Benefits		Other Benefits	
(In millions)	2018	2017	2018	2017
Service cost	$ 3.4	$ 3.2	$ 0.1	$ 0.1
Interest cost	6.4	6.9	0.7	0.8
Expected return on plan assets	(10.6)	(10.5)	—	—
Amortization of prior service cost	0.2	0.2	(1.1)	(1.2)
Amortization of actuarial loss	4.2	3.7	—	—
Settlement charge	—	1.9	—	—
Net periodic cost (benefit)	**$ 3.6**	**$ 5.4**	**$(0.3)**	**$(0.3)**

The service cost component is either included within *Other operating* in the Condensed Consolidated Statements of Income or is capitalized. The components of the net periodic benefit cost other than the service cost component are included within *Other income - net* in the Condensed Consolidated Statements of Income.

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. This ASU requires the Company to report the service cost component 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. Capitalization of net benefit cost is limited to only the service cost component of benefit costs, when applicable.

The ASU requires retrospective presentation of the service and non-service costs components in the income statement and prospective application regarding the capitalization of only the service cost component of net benefit costs. The Company has adopted the guidance effective January 1, 2018. In the three and six month periods ended June 30, 2017, $1.2 million was retroactively adjusted, decreasing *Other operating* and *Other income - net* in the Condensed Consolidated Statements of Income. The Company expects the guidance to have an immaterial impact to the Company's financial statements on an ongoing basis.

Employer Contributions to Qualified Pension Plans

In the six months ended June 30, 2018, the Company has made $3.5 million in contributions to its qualified pension plans.

7. Supplemental Cash Flow Information

As of June 30, 2018 and December 31, 2017, the Company has accruals related to utility and nonutility plant purchases totaling approximately $36.7 million and $28.6 million, respectively.

8. Investment in ProLiance Holdings, LLC

The Company has an investment in ProLiance Holdings, LLC (ProLiance), an affiliate of the Company and Citizens Energy Group (Citizens). Much of the ProLiance business was sold on June 18, 2013 when ProLiance exited the natural gas marketing business through the disposition of certain of the net assets of its energy marketing business, ProLiance Energy, LLC. The Company's remaining investment in ProLiance relates primarily to an investment in LA Storage, LLC (LA Storage). Consistent with its ownership percentage, the Company is allocated 61 percent of ProLiance's profits and losses; however, governance and voting rights remain at 50 percent for each member; and therefore, the Company accounts for its investment in ProLiance using the equity method of accounting. The Company's remaining investment at June 30, 2018, shown at its 61 percent ownership share of the individual net assets of ProLiance, is as follows:

(In millions)	As of June 30, 2018
Cash	$ 0.5
Investment in LA Storage	4.9
Total Investment in ProLiance	$ 5.4
Included in:	
Investments in unconsolidated affiliates	$ 1.0
Other nonutility investments	$ 4.4

LA Storage, LLC Storage Asset Investment

ProLiance Transportation and Storage, LLC (PT&S), a subsidiary of ProLiance, and Sempra Energy International (SEI), a subsidiary of Sempra Energy (SE), through a joint venture, have a 100 percent interest in a development project for salt-cavern natural gas storage facilities known as LA Storage. PT&S is the minority member with a 25 percent interest, which it accounts for using the equity method. On June 27, 2018, SE announced a plan to divest of certain natural gas storage assets and recorded an impairment charge related to the assets held for sale and other storage assets, such as LA Storage. As a result of SE's impairment of the LA Storage investment and the resulting charge recorded at Proliance, the Company recorded a $17.7 million charge to *Equity in (losses) of unconsolidated affiliates* in the three months ended June 30, 2018. The Company's remaining investment in Proliance is supported by the Company's share of the estimated fair value of LA Storage's land. As of June 30, 2018 and December 31, 2017, ProLiance's investment in the joint venture was $8.0 million and $36.8 million, respectively.

9. Income Taxes

Tax Cuts and Jobs Act

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. The IURC approved an initial reduction to the Company's current rates and charges, effective June 1, 2018, to capture the immediate impact of the lower corporate federal income tax rate. Also, on June 1, 2018, a settlement agreement, reached between the Company, the OUCC and a coalition of industrial customers, was filed with the IURC. The settlement agreement resolves all of the proposed changes to rates as a result of the TCJA, specifically regarding the refund of excess deferred taxes and the refund of the regulatory liabilities established starting January 1, 2018. The settlement agreement is pending before the Commission, and the Company expects an order in the third quarter. Once approved, the refund of excess deferred taxes and regulatory liabilities will commence starting no sooner than November 1, 2018 for the Company's Indiana electric customers and January 1, 2019 for the Company's Indiana gas customers.

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.

On February 9, 2018, through the signing into law of the Bipartisan Budget Act of 2018, Section 179D of the Internal Revenue Code, which provides for the energy efficiency commercial buildings tax deduction, was retroactively extended to 2017 for one year.

10. 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.

Utility Holdings Term Loan

On July 30, 2018, Utility Holdings executed a term loan agreement and closed a two-year term loan with two banking partners. The term loan agreement provides for a $250 million draw at closing and $50 million on or prior to December 31, 2018. Proceeds from the term loan have been utilized to pay a $100 million August 1, 2018, debt maturity and for general utility purposes. Accordingly, the Condensed Consolidated Balance Sheets reflect the current maturity and a portion of short-term borrowings as long-term at June 30, 2018. The term loan's interest rate is currently priced at one month LIBOR, plus a credit spread, which is subject to change based on changes in Utility Holdings' credit rating. A change in credit rating would add approximately 10 basis points, per rating notch, to the existing rate. In addition, the term loan contains a provision that should Utility Holdings or any of its subsidiaries execute certain capital market transactions, and subject to certain other conditions, the outstanding balance is subject to mandatory prepayment. The term loan is jointly and severally guaranteed by Utility Holdings' wholly-owned operating companies, SIGECO, Indiana Gas, and VEDO.

Utility Holdings and Vectren Capital Borrowing Arrangements

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 and Senior Notes issued by Vectren Capital in an aggregate principal amount of $260 million were issued. While the Merger would not result in an event of default under such note agreements, upon the consummation of the Merger the issuer would be required to offer to repurchase these notes at 100% of the principal amount thereof plus accrued interest.

The Merger is an event of default pursuant to the Company's two short-term credit facilities. Upon closing of the merger, CenterPoint will assume the obligations associated with these credit facilities.

11. Commitments & Contingencies

Performance Guarantees & Product Warranties

In the normal course of business, wholly owned subsidiaries, such as Energy Systems Group, LLC (ESG), a subsidiary of the Energy Services operating segment, issue payment and performance bonds and other forms of assurance that commit them to timely install infrastructure, operate facilities, pay vendors and subcontractors, and support warranty obligations.

Specific to ESG's role as a general contractor in the performance contracting industry, at June 30, 2018, there were 61 open surety bonds supporting future performance. The average face amount of these obligations is $10.3 million, and the largest obligation has a face amount of $75.9 million. The maximum exposure from these obligations is limited to the level of uncompleted work and further limited by bonds issued to ESG by various contractors. At June 30, 2018, approximately 30 percent of work was yet to be completed on projects with open surety bonds. A significant portion of these open surety bonds will be released within one year. In instances where ESG operates facilities, project guarantees extend over a longer period. In addition to its performance obligations, ESG also warrants the functionality of certain installed infrastructure generally for one year and the associated energy savings over a specified number of years.

Based on a history of meeting performance obligations and installed products operating effectively, no liability or cost has been recognized for the periods presented as the Company assesses the likelihood of loss as remote. Since inception, ESG has paid a de minimis amount on energy savings guarantees.

Corporate Guarantees & Other Support

The Company issues parent level guarantees to certain vendors and customers of its wholly owned subsidiaries. These guarantees do not represent incremental consolidated obligations; but rather, represent guarantees of subsidiary obligations in order to allow those subsidiaries the flexibility to conduct business without posting other forms of collateral. At June 30, 2018, parent level guarantees support a maximum of $426 million of ESG's performance contracting commitments, warranty obligations, project guarantees, and energy savings guarantees. Given the infrequent occurrence of any performance shortfalls historically on any of these commitments, no reserve for a potential liability has been deemed warranted.

Further, an energy facility operated by ESG and managed by Keenan Ft. Detrick Energy, LLC (Keenan), is governed by an operations agreement. Under this agreement, all payment obligations to Keenan are also guaranteed by the Company. The Company guarantee of the Keenan operations agreement does not state a maximum guarantee. Due to the nature of work performed under this contract, the Company cannot estimate a maximum potential amount of future payments but assesses the likelihood of loss as remote based on, primarily, the nature of the project.

The Company has not been called on to perform under these guarantees historically. While there can be no assurance that performance under these provisions will not be required in the future, the Company believes the likelihood of a material amount being incurred under these provisions is remote given the nature of the projects, the manner in which the savings estimates are developed, and the fact that the value of the guarantees decrease over time as actual energy savings are achieved.

The Company issues letters of credit that support consolidated operations. At June 30, 2018, letters of credit outstanding total $22.0 million.

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, including those described below, that are likely to have a material adverse effect on its financial condition, results of operations or cash flows.

Litigation Related to the Merger

As of August 2, 2018, seven purported Company shareholders have filed lawsuits under the federal securities laws in the United States District Court for the Southern District of Indiana challenging the adequacy of the disclosures made in the Company's proxy statement in connection with the merger. These cases are captioned *Kuebler v. Vectren Corp., et al.*, Case No. 3:18-cv-00113-RLY-MPB (S.D. Ind.) (the "Kuebler Action"), *Danigelis v. Vectren Corp., et al*., Case No. 3:18-cv-00114-RLY-MPB (S.D. Ind.) (the "Danigelis Action"), *Scarantino v. Vectren Corp., et al*., Case No. 3:18-cv-00115-RLY-MPB (S.D. Ind.) (the "Scarantino Action"), *Stein v. Vectren Corp., et al*., Case No. 3:18-cv-00117-RLY-MPB (S.D. Ind.) (the "Stein Action"), *Nisenshal v. Vectren Corp., et al.*, Case No. 3:18-cv-00121-RLY-MPB (S.D. Ind.) (the "Nisenshal Action"), *VonSalzen v. Vectren Corp., et al.*, Case No. 3:18-cv-00122-RLY-MPB (S.D. Ind.) (the "VonSalzen Action"), and *Kent v. Vectren Corp., et al.*, Case No. 1:18-cv-02263-SEB-TAB (S.D. Ind.) (the "Kent Action"). The Kuebler Action, the Danigelis Action, the Scarantino Action, the Nisenshal Action, and the Kent Action are asserted on behalf of putative classes of Company shareholders, while the Stein Action and the VonSalzen Action are brought only on behalf of their respective named plaintiffs.

All seven actions allege violations of Sections 14(a) and 20(a) of the Exchange Act and Rule 14a-9 promulgated thereunder based on various alleged omissions of material information from this proxy statement. The Kuebler Action, the Danigelis Action, the Stein Action, and the Nisenshal Action name as defendants the Company and each of our directors, individually, and seek to enjoin the merger (or, in the alternative, rescission or an award of rescissory damages in the event the merger is completed), damages, and an award of costs and attorneys' and expert fees. The Scarantino Action and Kent Action also name as defendants the Company and each of our directors, individually, and seek to enjoin the merger (or, in the alternative, rescission or an award of rescissory damages in the event the merger is completed), to compel our directors to issue a revised proxy statement, a declaration that the defendants violated Sections 14(a) and 20(a) of the Exchange Act and Rule 14a-9 promulgated thereunder, and an award of costs and attorneys' and expert fees, and damages. The VonSalzen Action also names as defendants the Company and each of our directors, individually, and seeks to enjoin the merger (or, in the alternative, rescission or an award of rescissory damages in the event the merger is completed), a declaration that the proxy statement is materially false or misleading, to compel our directors to account for damages, profits, and any special benefits obtained, and an award of costs and attorneys' and expert fees, and damages.

On July 10, 2018, the plaintiffs in the Kuebler Action and in the Danigelis Action filed motions for preliminary injunctions seeking to enjoin the Company from consummating the merger. On July 11, 2018, the plaintiffs in the Kuebler Action and in the Danigelis Action filed a motion for consolidation of the Kuebler Action, the Danigelis Action, the Scarantino Action, and the Stein Action and appointment of their counsel as interim class counsel. On July 12, 2018, the plaintiff in the VonSalzen Action filed a notice in support of the motion for consolidation and appointment of lead counsel filed in the Kuebler Action and Danigelis Action. On July 23, 2018, the plaintiff in the Nisenshal Action filed a notice in support of the motion for consolidation and appointment of lead counsel filed in the Kuebler Action and Danigelis Action. On July 25, 2018, the plaintiff in the Kent Action filed a motion for consolidation of the Kuebler Action, the Danigelis Action, the Scarantino Action, the Stein Action, the Nisenshal Action, the VonSalzen Action, and the Kent Action, for appointment as interim lead plaintiff, and approval of his counsel as interim class counsel. On July 31, 2018, Defendants filed their oppositions to the July 10, 2018 motions for preliminary injunction filed in the Kuebler Action and in the Danigelis Action. On August 1, 2018, the plaintiffs in the Kuebler Action and Danigelis Action filed a reply in support of their respective motions for consolidation, with a request to add the plaintiff from the Nisenshal Action and his counsel to the leadership group, and a response in opposition to the competing motion to consolidate filed by the plaintiff in the Kent Action.

The Company believes that these complaints are without merit. The Company cannot predict the outcome of or estimate the possible loss or range of loss from these matters.

12. 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.

On June 20, 2018, the Indiana Supreme Court issued an opinion (Opinion) in an appeal of an IURC order under Indiana Senate Bill 560 for a utility unrelated to the Company. In this Opinion, the Court determined that one of the programs within that utility's approved plan did not constitute a "designated" capital improvement because the individual projects within the program were not specifically set forth in the approved seven-year plan, and, instead were designated later based on subsequently developed information. The IURC had previously approved the program and thereby allowed individual projects under the program to be designated in the future and that action was then appealed by intervenors in the TDSIC proceeding. The Company has evaluated the opinion's potential application to the Company's Plan. The Company believes the ruling is limited to prospective projects that have not previously been designated and approved in final orders issued in the TDSIC process. The Company has determined that TDSIC projects in the service replacement plan category do not constitute a designated capital improvement, and therefore as a result of the Opinion is removing the associated projects that weren't previously the subject of final orders, totaling approximately $40 million over the remaining term of the plan. Such projects are still eligible for recovery in a future base rate case. The Company does not expect a resulting material impact to results of operations or cash flow from operations. On July 25, 2018, the Company filed revised schedules in the pending TDSIC proceeding to remove approximately $6 million of service replacement investments.

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 June 30, 2018 and December 31, 2017, the Company has regulatory assets related to the Plan totaling $82.9 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 $341.3 million as of June 30, 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 an additional $60.0 million of investments made through December 31, 2017. The Company expects an order by September 2018. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $34.8 million and $31.2 million at June 30, 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 June 30, 2018 and December 31, 2017, the Company has regulatory assets totaling $81.7 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.

13. 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, with the total approved plan set at $446.5 million. 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 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. These initial rates captured approved investments made through April 30, 2017.

On May 23, 2018, the IURC issued an order (May 2018 order) approving the inclusion in rates of investments made from May 2017 through October 2017. Through the May 2018 order, approximately $31 million of the approved capital investment plan has been incurred and approved for recovery.

On August 1, 2018, the Company submitted its third semi-annual filing, seeking approval of the recovery in rates of approximately $58 million through April 2018.

On June 20, 2018, the Indiana Supreme Court issued an opinion (Opinion) in an appeal of an IURC order under Indiana Senate Bill 560 for a utility unrelated to the Company. In this Opinion, the Court determined that one of the programs within that utility's approved plan did not constitute a "designated" capital improvement because the individual projects within the program were not specifically set forth in the approved seven-year plan, and, instead were designated later based on subsequently developed information. The IURC had previously approved the program and thereby allowed individual projects under the program to be designated in the future and that action was then appealed by intervenors in the TDSIC proceeding. The Company has evaluated the opinion's potential application of the Company's Plan. The Company believes the ruling is limited to prospective projects that have not previously been designated and approved in final orders issued in the TDSIC process. The Company has determined that TDSIC projects in the pole replacement plan category that weren't previously the subject of final orders, totaling approximately $35 million, do not constitute a designated capital improvement eligible for recovery given this Opinion. As the Company has the ability under the electric plan to substitute projects with other approved projects within defined annual cost caps, the Company does not expect this Opinion to impact the total amount of the approved plan, and therefore does not expect a resulting material impact to results of operations or cash flow from operations. The removal of the projects from the plan will occur when the company files its next TDSIC proceeding on August 1, 2018.

As of June 30, 2018 and December 31, 2017, the Company has regulatory assets related to the Electric TDSIC plan totaling $4.9 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 June 30, 2018, the Company has approximately $15.6 million deferred related to depreciation and operating expenses, and $5.6 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, as part of the electric generation transition plan case discussed below, 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.

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. Briefing is now complete. 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. Briefing is now complete. 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 June 30, 2018 and 2017, the Company recognized electric utility revenue of $5.9 million and $5.7 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 June 30, 2018, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $131.8 million at June 30, 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 $95 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.

A public field hearing was held on July 11, 2018. Intervenors must file testimony by August 10, 2018. Evidentiary hearings are scheduled to commence October 9, 2018. On July 18, 2018, a group of intervenors, including the Indiana Coal Council, motioned for Summary Judgment, requesting that the Commission deny the CPCN authorizing construction, or extend the procedural schedule a minimum of 45 days after the Commission issues its annual statewide analysis for expansion of facilities for the generation of electricity, which is to be filed before October 1st of each year. The Company believes the request for summary judgment to be without merit and does not expect it to result in a revision to the CPCN proceeding's procedural schedule. The Company expects an order from the Commission in the CPCN 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. Filed testimony of intervening parties is expected on September 4, 2018, and an evidentiary hearing is scheduled for September 26, 2018. 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 and CCR 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.

On September 28, 2017, the Department of Energy (DOE) issued a Notice of Proposed Rulemaking (NOPR) to the FERC for consideration of payment to certain resources that have on-site fuel and demonstrate a form of resilience. On January 8, 2018, after receiving a majority of comments from the Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) opposing the relief requested by the DOE, the FERC declined to issue the NOPR and, instead, initiated a proceeding (FERC Docket No. AD18-7) to further explore the current planning that RTOs and ISOs are undertaking to ensure resiliency, as well as other regional aspects to determine the need for action of the type recommended by the DOE. This proceeding is still pending before the FERC. In the interim, a draft memorandum that was purportedly prepared by the DOE was made public on May 31, 2018. The draft memorandum calls for immediate action by the President of the United States to exercise authority under the Defense Production Act and Federal Power Act to provide for temporary subsidy payments to coal and nuclear resources while a two year study is performed to identify Defense Critical Electric Infrastructure (DCEI). The draft memorandum expands upon the original resiliency concerns expressed in the DOE's September 28, 2017 submission. Following the publication of the draft DOE memorandum, President Trump publicly called for immediate action by the DOE. To date, the DOE has not publicly taken action, including finalizing the draft memorandum and indicating facilities that would be eligible for these temporary subsidy payments or how they would be funded. At this time, the Company does not believe this activity will have any impact on its pending request for authorization from the IURC to construct a combined cycle gas turbine to serve the requirements of the Company's electric utility system. Absent further information, the impact to electric customers and power generator owners is unknown.

14. 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 $446.5 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. On July 17, 2018, EPA released its final CCR rule phase I reconsideration which extends for two years, from October 31, 2018 to October 31, 2020, the deadline for ceasing placement of ash in ponds that exceed groundwater protections standards or fails to meet location restrictions. The Company does not anticipate the reconsideration to change its current plans for pond closure as announced in its generation transition plan, since closure dates were not dependent upon the original October 2018 compliance date. 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 June 30, 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.

On July 20, 2018, the Company filed a Complaint for Damages and Declaratory Relief against its insurers seeking reimbursement of defense, investigation, and pond closure costs incurred to comply with the CCR rule. The Company intends to apply any net proceeds from this litigation to offset costs that have been and will be deferred for future recovery from customers.

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 13.

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. On July 23, 2018, the U.S. Court of Appeals for the Second Circuit upheld the final rule on judicial review. 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.

<u>Air Quality</u>

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 SO_2 NAAQS. The Company's coal-fired generating fleet is 100 percent scrubbed for SO_2 and 90 percent controlled for NO_x.

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 $15.8 million of the expected $15.8 million in insurance recoveries.

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company’s utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of June 30, 2018 and December 31, 2017, approximately $2.4 million and $2.5 million, respectively of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

15. 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 will adopt the guidance effective January 1, 2019 and is evaluating available practical expedients and the standard to determine the impact it will have on the financial statements.

Other Recently Issued Standards

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

16. Fair Value Measurements

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

	June 30, 2018		December 31, 2017	
(In millions)	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	$1,988.7	$2,072.7	$1,838.7	$1,981.2
Short-term borrowings	247.9	247.9	249.5	249.5
Cash & cash equivalents	9.8	9.8	16.6	16.6
Natural gas purchase instrument assets (1)	—	—	0.5	0.5
Natural gas purchase instrument liabilities (2)	11.8	11.8	4.5	4.5
Interest rate swap assets (3)	1.5	1.5	—	—
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.

Because of the nature of certain other investments and lack of a readily available market, it is not practical to estimate the fair value of these financial instruments at specific dates without considerable effort and cost. At June 30, 2018 and December 31, 2017, the fair value for these financial instruments was not estimated. The carrying value of these investments was $9.6 million at each of June 30, 2018 and December 31, 2017.

17. Segment Reporting

The Company segregates its operations into three groups: 1) Utility Group, 2) Nonutility Group, and 3) Corporate and Other.

The Utility Group is comprised of Vectren Utility Holdings, Inc.'s operations, which consist of the Company's 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 Utility Group is comprised of three operating segments: Gas Utility Services, Electric Utility Services, and Other Utility Operations.

The Nonutility Group reports the following segments: Infrastructure Services, Energy Services, and Other Nonutility Businesses. The Infrastructure Services segment, through wholly owned subsidiaries Miller Pipeline, LLC and Minnesota Limited, LLC, provides underground pipeline construction and repair services for customers that include Vectren Utility Holdings' utilities. Fees incurred by Vectren Utility Holdings and its subsidiaries for these pipeline construction and repair services totaled $39.8 million and $51.6 million for the three months ended June 30, 2018 and 2017, respectively, and for the six months ended June 30, 2018 and 2017 totaled $64.4 million and $77.4 million, respectively. Energy Services, through the wholly owned subsidiary Energy Systems Group, LLC, provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects.

Corporate and Other includes unallocated corporate expenses such as advertising and certain charitable contributions, among other activities, that benefit the Company's other operating segments. Net income is the measure of profitability used by management for all operations.

Information related to the Company's reportable segments is summarized as follows:

(In millions)	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Revenues				
Utility Group				
Gas Utility Services	$149.3	$144.0	$ 478.6	$ 436.8
Electric Utility Services	143.3	141.8	277.4	273.8
Other Operations	11.8	11.4	23.6	22.8
Eliminations	(11.7)	(11.3)	(23.5)	(22.7)
Total Utility Group	**292.7**	**285.9**	**756.1**	**710.7**
Nonutility Group				
Infrastructure Services	279.4	277.5	414.7	424.8
Energy Services	73.8	67.8	134.4	120.7
Total Nonutility Group	**353.2**	**345.3**	**549.1**	**545.5**
Corporate & Other Group	0.1	0.2	0.2	0.3
Eliminations	(1.7)	(0.7)	(2.6)	(1.4)
Consolidated Revenues	**$644.3**	**$630.7**	**$1,302.8**	**$1,255.1**
Profitability Measure - Net Income				
Utility Group Net Income				
Gas Utility Services	$ 5.3	$ 7.0	$ 61.3	$ 54.9
Electric Utility Services	17.8	15.9	31.8	29.6
Other Operations	2.4	2.6	6.7	6.9
Utility Group Net Income	**25.5**	**25.5**	**99.8**	**91.4**
Nonutility Group Net Income (Loss)				
Infrastructure Services	19.7	11.4	3.9	2.1
Energy Services	2.2	1.1	7.7	—
Other Nonutility Businesses	(13.3)	(0.3)	(13.6)	(0.4)
Nonutility Group Net Income (Loss)	**8.6**	**12.2**	**(2.0)**	**1.7**
Corporate & Other Group Net Income (Loss)	(11.9)	(0.1)	(12.1)	(0.2)
Consolidated Net Income	**$ 22.2**	**$ 37.6**	**$ 85.7**	**$ 92.9**

UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL INFORMATION

The Unaudited Pro Forma Condensed Combined Financial Statements (pro forma financial statements) have been derived from the historical consolidated financial statements of CenterPoint Energy, Inc. (CenterPoint Energy) and Vectren Corporation (Vectren). The following pro forma financial statements should be read in conjunction with:

- the accompanying notes to the Unaudited Pro Forma Condensed Combined Financial Statements;
- the consolidated financial statements of CenterPoint Energy as of and for the year ended December 31, 2017, included in CenterPoint Energy's Annual Report on Form 10-K for the fiscal year ended December 31, 2017, filed with the Securities and Exchange Commission (SEC) on February 22, 2018;
- the unaudited consolidated financial statements of CenterPoint Energy as of and for the six months ended June 30, 2018, included in CenterPoint Energy's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2018, filed with the SEC on August 3, 2018;
- the consolidated financial statements of Vectren as of and for the year ended December 31, 2017, attached as Exhibit 99.1 to this Current Report on Form 8-K; and
- the unaudited consolidated financial statements of Vectren as of and for the six months ended June 30, 2018, attached as Exhibit 99.2 to this Current Report on Form 8-K.

On April 21, 2018, CenterPoint Energy entered into an Agreement and Plan of Merger (Merger Agreement), by and among CenterPoint Energy, Vectren and Pacer Merger Sub, Inc., an Indiana corporation and wholly owned subsidiary of CenterPoint Energy (Merger Sub). Pursuant to the Merger Agreement, on and subject to the terms and conditions set forth therein, Merger Sub will merge with and into Vectren (Vectren Merger), with Vectren continuing as the surviving corporation in the Vectren Merger and becoming a wholly owned subsidiary of CenterPoint Energy.

The Unaudited Pro Forma Condensed Combined Statements of Income (pro forma statements of income) for the six months ended June 30, 2018, and the year ended December 31, 2017, give effect to the Vectren Merger as if it were completed on January 1, 2017. The Unaudited Pro Forma Condensed Combined Balance Sheet (pro forma balance sheet) as of June 30, 2018, gives effect to the Vectren Merger as if it were completed on June 30, 2018.

The historical financial information has been adjusted in the pro forma financial statements to give effect to pro forma events that are (i) directly attributable to the Vectren Merger, (ii) factually supportable and (iii) with respect to the statements of income, expected to have a continuing impact on the combined results of CenterPoint Energy and Vectren.

The Vectren Merger will be accounted for as an acquisition of Vectren common shares by CenterPoint Energy and will follow the acquisition method of accounting for business combinations. The pro forma financial statements reflect an aggregate purchase price of approximately $6.0 billion in cash, based upon the "Merger Consideration" (as defined in the Merger Agreement) of $72.00 per share for each share of common stock of Vectren issued and outstanding immediately prior to the Vectren Merger.

CenterPoint Energy has obtained committed financing in the form of a $5.0 billion senior unsecured bridge term loan facility (Bridge Facility) from Goldman Sachs Bank USA and Morgan Stanley Senior Funding, Inc. Any borrowings under the Bridge Facility would be classified as short-term debt in current liabilities. CenterPoint Energy has prepared its pro forma financial statements in accordance with the applicable accounting rules assuming the aggregate purchase price will be financed by borrowings under the Bridge Facility and CenterPoint Energy's existing revolving credit facility and the issuance by CenterPoint Energy of $500 million of its Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Stock, par value $0.01 per share (Series A Preferred Stock). However, CenterPoint Energy anticipates financing the Vectren Merger through its expected issuances of Series A Preferred Stock, common stock, mandatory convertible equity securities, debt securities and commercial paper, subject to then current market conditions, as well as cash on hand. CenterPoint Energy's permanent financing assumptions are detailed in the accompanying notes.

Assumptions and estimates underlying the pro forma adjustments are described in the accompanying notes, which should be read with the pro forma financial statements. Because the pro forma financial statements have been prepared on preliminary estimates, the total amounts recorded at the date of the Vectren Merger may differ materially from the information presented in the pro forma financial statements. These estimates are subject to change pending further review of the assets acquired and liabilities assumed in the Vectren Merger and the final purchase price of the Vectren Merger.

The pro forma financial statements have been presented for illustrative purposes only and are not necessarily indicative of the results of operations and financial position that would have been achieved had the pro forma events taken place on the dates indicated, or the future consolidated results of operations or financial position of the combined company.

CENTERPOINT ENERGY, INC.
UNAUDITED PRO FORMA CONDENSED COMBINED BALANCE SHEET
June 30, 2018

	CenterPoint Energy Historical	Vectren Historical (Note 6)	Pro Forma Adjustments (Note 4)		CenterPoint Energy Pro Forma
	(In Millions)				
Current Assets:					
Cash and cash equivalents	$ 328	$ 10	—	(a)	$ 328
			(10)	(g)	
Investment in marketable securities	584	—	—		584
Accounts receivable, net	958	232	—		1,190
Accrued unbilled revenues	207	148	—		355
Natural gas and fuel inventory	152	51	—		203
Materials and supplies	192	53	—		245
Non-trading derivative assets	74	—	—		74
Taxes receivable	39	—	—		39
Prepaid expenses and other current assets	167	53	—		220
Total current assets	2,701	547	(10)		3,238
Property, Plant and Equipment, net	13,397	4,923	—		18,320
Other Assets:					
Goodwill	867	293	4,156	(b)	5,316
Regulatory assets	2,067	441	(107)	(d)	2,401
Non-trading derivative assets	46	—	—		46
Investment in unconsolidated affiliate	2,451	2	—		2,453
Preferred units – unconsolidated affiliate	363	—	—		363
Intangible assets	69	30	170	(c)	269
Other	147	60	(18)	(h)	233
			(2)	(i)	
			46	(g)	
Total other assets	6,010	826	4,245		11,081
Total Assets	$ 22,108	6,296	4,235		32,639

See Notes to Unaudited Pro Forma Condensed Combined Financial Statements

CENTERPOINT ENERGY, INC.
UNAUDITED PRO FORMA CONDENSED COMBINED BALANCE SHEET — (continued)
June 30, 2018

	CenterPoint Energy Historical	Vectren Historical (Note 6)	Pro Forma Adjustments (Note 4)		CenterPoint Energy Pro Forma
	(In Millions)				
Current Liabilities:					
Short-term borrowings	$ —	$ 248	4,460	(h)	$ 4,744
			36	(g)	
Current portion of VIE Securitization Bonds long-term debt	446	—	—		446
Indexed debt, net	26	—	—		26
Current portion of other long-term debt	50	60	—		110
Indexed debt securities derivative	641	—	—		641
Accounts payable	706	225	43	(e)	1,015
			41	(f)	
Taxes accrued	103	45	—		148
Interest accrued	118	19	—		137
Non-trading derivative liabilities	26	—	—		26
Due to ZENS note holders	382	—	—		382
Other	344	167	—		511
Total current liabilities	2,842	764	4,580		8,186
Other Liabilities:					
Deferred income taxes, net	3,168	501	15	(j)	3,684
Non-trading derivative liabilities	12	—	—		12
Benefit obligations	723	151	—		874
Regulatory liabilities	2,521	943	—		3,464
Other	412	146	—		558
Total other liabilities	6,836	1,741	15		8,592
Long-term Debt:					
VIE Securitization Bonds, net	1,193	—	—		1,193
Other long-term debt, net	6,567	1,929	1,010	(i)	9,506
Total long-term debt, net	7,760	1,929	1,010		10,699
Shareholders' Equity:					
Cumulative preferred stock	—	—	—		—
Series A Preferred Stock	—	—	—	(k)	—
Common stock	4	739	(739)	(l)	4
Additional paid-in-capital	4,215	—	492	(k)	4,707
Retained earnings	513	1,124	(1,040)	(l)	513
			(43)	(e)	
			(41)	(f)	
Accumulated other comprehensive loss	(62)	(1)	1	(l)	(62)
Total shareholders' equity	4,670	1,862	(1,370)		5,162
Total Liabilities and Shareholders' Equity	$ 22,108	$ 6,296	$ 4,235		$ 32,639

See Notes to Unaudited Pro Forma Condensed Combined Financial Statements

CENTERPOINT ENERGY, INC.
UNAUDITED PRO FORMA CONDENSED COMBINED STATEMENT OF INCOME
For the Six Months Ended June 30, 2018

	CenterPoint Energy Historical	Vectren Historical (Note 6)	Pro Forma Adjustments (Note 5)		CenterPoint Energy Pro Forma
	(In Millions, Except Per Common Share Amounts)				
Revenues:					
Utility revenues	$ 3,235	$ 756	$ —		$ 3,991
Non-utility revenues	2,106	547	—		2,653
Total	5,341	1,303	—		6,644
Expenses:					
Utility natural gas, fuel and purchased power	825	277	—		1,102
Non-utility cost of revenues, including natural gas	2,063	178	—		2,241
Operation and maintenance	1,147	528	(36)	(d)	1,639
Depreciation and amortization	656	144	10	(b)	810
Taxes other than income taxes	212	36	—		248
Total	4,903	1,163	(26)		6,040
Operating Income	438	140	26		604
Other Income (Expense):					
Gain on marketable securities	23	—	—		23
Loss on indexed debt securities	(272)	—	—		(272)
Interest and other finance charges	(169)	(32)	(147)	(a)	(348)
Interest on Securitization Bonds	(30)	—	—		(30)
Equity in earnings of unconsolidated affiliate, net	127	(18)	—		109
Other, net	7	4	—		11
Total	(314)	(46)	(147)		(507)
Income Before Income Taxes	124	94	(121)		97
Income tax expense (benefit)	34	8	(29)	(e)	13
Net Income	90	86	(92)		84
Series A Preferred Stock dividend	—	—	15	(c)	15
Earnings available to common shareholders	$ 90	$ 86	$ (107)		$ 69
Basic Earnings Per Common Share	$ 0.21				$ 0.16
Diluted Earnings Per Common Share	$ 0.21				$ 0.16
Weighted Average Common Shares Outstanding, Basic	431				431
Weighted Average Common Shares Outstanding, Diluted	434				434

See Notes to Unaudited Pro Forma Condensed Combined Financial Statements

CENTERPOINT ENERGY, INC.
UNAUDITED PRO FORMA CONDENSED COMBINED STATEMENT OF INCOME
For the Year Ended December 31, 2017

	CenterPoint Energy Historical	Vectren Historical (Note 6)	Pro Forma Adjustments (Note 5)		CenterPoint Energy Pro Forma
	(In Millions, Except Per Common Share Amounts)				
Revenues:					
Utility revenues	$ 5,603	$ 1,382	$ —		$ 6,985
Non-utility revenues	4,011	1,275	—		5,286
Total	9,614	2,657	—		12,271
Expenses:					
Utility natural gas, fuel and purchased power	1,109	444	—		1,553
Non-utility cost of revenues, including natural gas	3,785	444	—		4,229
Operation and maintenance	2,221	1,116	—		3,337
Depreciation and amortization	1,036	276	17	(b)	1,329
Taxes other than income taxes	391	59	—		450
Total	8,542	2,339	17		10,898
Operating Income	1,072	318	(17)		1,373
Other Income (Expense):					
Gain on marketable securities	7	—	—		7
Loss on indexed debt securities	49	—	—		49
Interest and other finance charges	(313)	(62)	(307)	(a)	(682)
Interest on Securitization Bonds	(77)	—	—		(77)
Equity in earnings of unconsolidated affiliate, net	265	(1)	—		264
Other, net	60	7	—		67
Total	(9)	(56)	(307)		(372)
Income Before Income Taxes	1,063	262	(324)		1,001
Income tax expense (benefit)	(729)	46	(77)	(e)	(760)
Net Income	1,792	216	(247)		1,761
Series A Preferred Stock dividend	—	—	30	(c)	30
Earnings available to common shareholders	$ 1,792	$ 216	$ (277)		$ 1,731
Basic Earnings Per Common Share	$ 4.16				$ 4.02
Diluted Earnings Per Common Share	$ 4.13				$ 3.99
Weighted Average Common Shares Outstanding, Basic	431				431
Weighted Average Common Shares Outstanding, Diluted	434				434

See Notes to Unaudited Pro Forma Condensed Combined Financial Statements

(1) Basis of presentation

The pro forma statements of income for the six months ended June 30, 2018, and the year ended December 31, 2017, give effect to the Vectren Merger as if it were completed on January 1, 2017. The pro forma balance sheet as of June 30, 2018, gives effect to the Vectren Merger as if it were completed on June 30, 2018.

The pro forma financial statements have been derived from the historical consolidated financial statements of CenterPoint Energy and Vectren. Certain financial statement line items included in Vectren's historical presentation have been reclassified to conform to corresponding financial statement line items included in CenterPoint Energy's historical presentation (see Note 6). These reclassifications have no material impact on the historical operating income, net income, total assets, total liabilities or shareholders' equity reported by CenterPoint Energy or Vectren. The historical consolidated financial statements have been adjusted in the pro forma financial statements to give effect to pro forma events that are (1) directly attributable to the business combination, (2) factually supportable and (3) with respect to the pro forma statements of income, expected to have a continuing impact on the combined results following the Vectren Merger.

Assumptions and estimates underlying the pro forma adjustments are described in these notes, which should be read in conjunction with the pro forma financial statements. Since the pro forma financial statements have been prepared based upon preliminary estimates, the final amounts recorded at the date of the Vectren Merger may differ materially from the information presented. These estimates are subject to change pending further review.

The Vectren Merger is reflected in the pro forma financial statements as an acquisition of Vectren by CenterPoint Energy, based on the guidance provided by accounting standards for business combinations. Under these accounting standards, the total estimated purchase price is allocated as described in Note 2 to the pro forma financial statements, and the assets acquired and the liabilities assumed have been measured at estimated fair value.

Vectren's regulated operations are comprised of electric generation and electric and natural gas energy delivery services. These operations are subject to the rate-setting authority of the Federal Energy Regulatory Commission, the Indiana Utility Regulatory Commission and the Public Utilities Commission of Ohio, and are accounted for pursuant to U.S. generally accepted accounting principles, including the accounting guidance for regulated operations. The rate-setting and cost-recovery provisions currently in place for Vectren's regulated operations provide revenue derived from costs including a return on investment of assets and liabilities included in rate base. Thus, the fair values of Vectren's tangible and intangible assets and liabilities subject to these rate-setting provisions approximate their carrying values, and the pro forma financial statements do not reflect any net adjustments related to these amounts. Therefore, the excess purchase price over carrying value of net assets attributable to regulated operations is estimated to be compromised entirely of goodwill. The carrying values of Vectren's non-regulated property, plant and equipment, which consists primarily of vehicles and equipment, and long-term debt, including the elimination of debt issuance costs, as of June 30, 2018, were reviewed and determined to approximate fair value; therefore, no fair value adjustment was reflected in the pro forma financial statements related to these balances.

The accounting policies used in the preparation of the pro forma financial statements are those described in CenterPoint Energy's audited consolidated financial statements as of and for the year ended December 31, 2017. CenterPoint Energy performed a preliminary review of Vectren's accounting policies to determine whether any adjustments were necessary to ensure comparability in the pro forma financial statements. At this time, CenterPoint Energy is not aware of any differences that would have a material effect on the pro forma financial statements, including any differences in the timing of adoption of new accounting standards, except for certain amounts that have been reclassified to conform to CenterPoint Energy's financial statement presentation (see Note 6). Upon completion of the Vectren Merger, or as more information becomes available, CenterPoint Energy will perform a more detailed review of Vectren's accounting policies. As a result of that review, differences may be identified between the accounting policies of the two companies that, when conformed, could have a material impact on the pro forma financial statements. The 2017 historical statements of income for CenterPoint Energy and Vectren do not reflect new accounting standards retrospectively adopted on January 1, 2018.

CenterPoint Energy reviewed the historical financial information for intercompany transactions and found no eliminations were necessary. Transaction costs recorded in the historical income statement have been excluded from the pro forma statements of income as they reflect nonrecurring charges directly related to the Vectren Merger. However, the transaction costs not recorded in the historical balance sheet are reflected in the pro forma balance sheet as an increase in other current liabilities and a decrease in retained earnings when such amounts are not reflected in the historical balance sheet.

The pro forma financial statements do not reflect the realization of any expected cost savings or other synergies from the Vectren Merger as a result of restructuring activities following the completion of the Vectren Merger. Certain of Vectren employment agreements contain severance or other termination arrangements; however, the pro forma financial statements do not reflect any such payments under these arrangements as employment decisions have not been finalized.

(2) Estimated Purchase Price Consideration and Preliminary Purchase Price Allocation

The estimated purchase price consideration of approximately $6.0 billion is based on the cash price of $72.00 per outstanding share of common stock of Vectren. The value of the purchase price consideration will change based on the actual number of shares of common stock of Vectren issued and outstanding immediately prior to the Vectren Merger.

Estimated Vectren common shares outstanding as of June 30, 2018		83,080,695
Cash consideration per Vectren common share	$	72.00
Total estimated cash consideration to be paid (in millions)	$	5,982

CenterPoint Energy has performed a preliminary valuation analysis of the fair market value of Vectren's assets and liabilities. The following table summarizes the allocation of the preliminary purchase price as of the acquisition date (in millions):

Current assets	$ 537
Property, plant and equipment, net	4,923
Identifiable intangibles	200
Regulatory assets	334
Other assets	108
Total assets acquired	6,102
Current liabilities	884
Other liabilities	1,756
Long-term debt	1,929
Total liabilities assumed	4,569
Net assets acquired	1,533
Goodwill	4,449
Total purchase price consideration	$5,982

This preliminary purchase price allocation has been used to prepare pro forma adjustments in the pro forma balance sheet and income statement. CenterPoint Energy has not completed a final valuation analysis necessary to determine the fair market values of all of Vectren's assets and liabilities or the allocation of its purchase price. The final allocation could differ materially from the preliminary allocation used in the pro forma adjustments. The final allocation may include (1) changes in fair values of property, plant and equipment, (2) changes in allocations to intangible assets and goodwill and (3) other changes to assets and liabilities.

(3) Financing Transactions

CenterPoint Energy sometimes refers to the planned issuance and sale of its common stock, mandatory convertible equity securities, Series A Preferred Stock, debt securities and commercial paper as described below (collectively, the Additional Financings). The actual size and terms of, and amounts of proceeds CenterPoint Energy receives from, the respective Additional Financings will depend on, among other things, market conditions at the time of the Additional Financings and such other factors as CenterPoint Energy deems relevant and may differ, perhaps substantially, from the size, terms and amounts CenterPoint Energy has assumed in this Note 3 to the pro forma financial statements.

As required by accounting rules and for purposes of the pro forma financial statements, CenterPoint Energy has assumed the following to fund the approximately $6.0 billion cash consideration purchase price further described below:

- borrowings of $4.5 billion under the Bridge Facility;
- issuance of $500 million of Series A Preferred Stock; and
- borrowings of $1.0 billion under its existing revolving credit facility.

CenterPoint Energy obtained commitments by lenders for a $5.0 billion, 364-day Bridge Facility to provide flexibility for the timing of the acquisition financing and fund, in part, amounts payable by CenterPoint Energy in connection with the Vectren Merger. For purposes of the pro forma financial statements, CenterPoint Energy's assumed borrowings under the Bridge Facility of $4.5 billion were reduced by the assumed issuance of $500 million of Series A Preferred Stock. For purposes of the pro forma financial statements, CenterPoint Energy has assumed a weighted-average interest rate of 5.3%, which includes duration and drawn fees on the $4.5 billion Bridge Facility borrowings. Drawn fees are estimated based on current 1-month LIBOR of 2.08% as of August 7, 2018, plus applicable margin under the Bridge Facility agreements. The Bridge Facility bears interest at an annual rate equal to LIBOR plus a margin ranging from 1.0% to 2.0%, depending on our credit rating, subject to an increase of 0.25% for each 90 days that elapse after the closing of the Vectren Merger. Assuming CenterPoint Energy, Inc.'s current credit ratings, the applicable margin increases 0.25% each 90 days after the closing of the Vectren Merger, from 1.25% to a maximum of 2.00%. Upon execution of the Bridge Facility, CenterPoint Energy deferred debt issuance costs of $25 million in other assets, of which $7 million was amortized as debt issuance expense in the historical financial statements as of and for the six months ended June 30, 2018.

For purposes of the pro forma financial statements, CenterPoint Energy has presented the issuance of 500,000 shares of its Series A Preferred Stock for $492 million, net of $8 million of issuance costs and discounts, with an aggregate liquidation value of $500 million, and that those shares will require CenterPoint Energy to pay dividends in cash, calculated as a percentage of the aggregate liquidation value, at the rate of 6% per annum. This assumed dividend rate is based on current market conditions. The actual dividend rate on the Series A Preferred Stock at the time it is issued may differ, perhaps substantially, from the rate CenterPoint Energy has assumed for purposes of the pro forma financial statements. In addition, CenterPoint Energy has further assumed that none of the shares of the Series A Preferred Stock have been redeemed early by CenterPoint Energy during the periods presented in the pro forma financial statements.

In May 2018, CenterPoint Energy entered into an amendment to its revolving credit facility (as so amended, the Revolving Credit Facility) that will increase the aggregate commitments from $1.7 billion to $3.3 billion effective the earlier of (i) the termination of all commitments by certain lenders to provide the Bridge Facility and (ii) the payment in full of all obligations (other than contingent obligations) under the Bridge Facility and termination of all commitments to advance additional credit thereunder, and in each case, so long as the Merger Agreement has not been terminated pursuant to the terms thereof without consummation of the Vectren Merger. For purposes of the pro forma financial statements, CenterPoint Energy has assumed the balance of the purchase price consideration will be met by borrowings of approximately $1.0 billion under the Revolving Credit

Facility at a weighted-average interest rate of 3.6%. Interest expense reflected in the pro forma financial statements includes arranger and commitments fees, as well as estimated interest on drawn amounts based on current 1-month LIBOR of 2.08% as of August 8, 2018, plus applicable rate under the Revolving Credit Facility, assuming current CenterPoint Energy, Inc. issuer credit ratings.

In lieu of borrowings under the Bridge Facility and the Revolving Credit Facility, CenterPoint Energy intends to execute the Additional Financings described below prior to the close of the Vectren Merger:

(1) In addition to the net proceeds from the $500 million of Series A Preferred Stock, CenterPoint Energy intends to raise approximately $2.25 billion from the issuance of a combination of common stock and mandatory convertible equity securities based on current market conditions. The actual proceeds from these issuances may differ, perhaps substantially, from the proceeds assumed for purposes of the pro forma financial statements.

(2) CenterPoint Energy intends to issue a combination of debt securities and commercial paper aggregating $3.25 billion, net of issuance costs of $20 million, with an assumed weighted-average interest rate (including the index rate plus a credit spread) of 4% per annum. This assumed rate is based on borrowing costs for debt securities and commercial paper under current market conditions, presently expected to range from approximately 2.30% for commercial paper to up to 4.50% for senior notes. The actual interest rate and original issue discount on the debt will be based on market conditions at the time the debt is issued and may differ, perhaps substantially, from the rate and discount assumed for purposes of the pro forma financial statements. Furthermore, any cash on hand may be used to reduce the balance of debt securities or commercial paper incurred to finance the Vectren Merger.

Because the Additional Financings are contemplated to take place in the future, the pro forma financial statements were prepared in accordance with the accounting rules assuming that the Merger Consideration will be financed from drawings under the Bridge Facility and under the Revolving Credit Facility and through the proceeds from the issuance of the Series A Preferred Stock. However, CenterPoint Energy currently does not intend to draw on the Bridge Facility or its Revolving Credit Facility but rather intends to fund the Merger Consideration with proceeds received through the Additional Financings, the proceeds from the issuance of the Series A Preferred Stock and cash on hand, although there is no guarantee that CenterPoint Energy will be able to consummate the Additional Financings as planned or at all.

(4) Adjustments to Pro Forma Balance Sheet

The pro forma adjustments are based on our preliminary estimates and assumptions that are subject to change. The following adjustments have been reflected in the pro forma balance sheet:

(a) *Cash and cash equivalents.* Reflects pro forma adjustment to cash and cash equivalents.

	(in millions)	Reference Note
Proceeds from the issuance of Series A Preferred Stock, net	$ 492	Note 4(k)
Borrowings under Bridge Facility, net	4,478	Note 4(h)
Borrowings under the Revolving Credit Facility	1,012	Note 4(i)
Estimated cash consideration	(5,982)	Note 2
Net adjustment to cash and cash equivalents	$ —	

(b) *Goodwill.* Reflects the elimination of Vectren's historical goodwill and the preliminary estimated goodwill resulting from the purchase price consideration in excess of the fair value of the net assets acquired in connection with the Vectren Merger.

	(in millions)
Elimination of Vectren's existing goodwill	$ (293)
Preliminary estimated goodwill resulting from Vectren Merger	4,449
Net adjustment to goodwill	$ 4,156

(c) *Intangible assets.* Reflects the preliminary purchase accounting adjustment for estimated intangible assets based on the acquisition method of accounting.

	Estimated Useful Lives (in years)	(in millions)
Elimination of Vectren's existing intangible assets		$ (30)
Preliminary operation and maintenance agreements	8-12	49
Preliminary backlog	1-2	78
Preliminary customer relationships	3-5	73
Net adjustment to intangible assets (1)		$ 170

(1) Reflects the adjustment to increase the basis in intangible assets to estimated fair value. The estimated fair value is expected to be amortized over the estimated useful lives. The fair value and useful life calculations are preliminary and subject to change.

(d) *Regulatory assets.* Reflects the preliminary purchase accounting adjustment for regulatory assets not earning a return based on the acquisition method of accounting.

	Estimated Useful Lives (in years)	(in millions)
Elimination of Vectren's regulatory assets not earning a return (1)		$ (287)
Preliminary valuation of Vectren's regulatory assets not earning a return	3-34	180
Net adjustment to regulatory assets (2)		$ (107)

(1) Vectren's historical balance sheet as of June 30, 2018, reflects regulatory assets of $441 million, of which $287 million are not earning a return.

(2) The valuation and useful life calculations are preliminary and subject to change.

(e) *Transaction costs.* Reflects the accrual of estimated Vectren Merger transaction costs of $43 million consisting of fees related to advisory services to be paid by Vectren upon closing of the Vectren Merger, all of which are directly attributable to the Vectren Merger and not recorded in the historical balance sheet. These costs have not been reflected on the pro forma income statements as they will not have an ongoing impact on the results of the combined company.

(f) *Stock-based compensation.* Reflects the vesting and cash out of $41 million in the unvested stock units and performance units (at target), inclusive of unpaid dividends, held by Vectren's employees and non-employee directors upon closing of the Vectren Merger, approximating 568,371 units, inclusive of units for unpaid dividends, at $72.00 per unit. Pursuant to the Merger Agreement, the performance units will vest at the greater of target or actual results; accordingly, the value of these payments could be greater than the amount reflected in the adjustment. These costs have not been reflected on the pro forma income statements as they will not have an ongoing impact on the results of the combined company.

(g) *Deferred compensation.* Reflects the funding of the trusts underlying Vectren's two unfunded nonqualified deferred compensation plans and one unfunded supplemental executive retirement plan totaling $46 million that will be contributed by Vectren immediately prior to closing of the Vectren Merger. Trust funding requirements in excess of cash on hand immediately prior to closing will be financed with Vectren's short-term borrowings. Certain benefit payments under the plans will be payable from the trust within 60 days upon closing of the Vectren Merger.

(h) *Short-term debt*. Reflects borrowings under the Bridge Facility to finance a portion of the Vectren Merger purchase price.

	(in millions)
Proceeds from borrowings under the Bridge Facility	$ 4,500
Debt issuance fees	(22)
Net proceeds from borrowings under the Bridge Facility	4,478
Reclassify debt issuance fees recorded in historical balance sheet (1)	(18)
Net adjustment to short-term debt	$ 4,460

(1) Recorded in Other assets in CenterPoint Energy's historical balance sheet as there is no outstanding debt under the Bridge Facility as of June 30, 2018.

(i) *Long-term debt*. Reflects borrowings under the Revolving Credit Facility to finance a portion of the Vectren Merger purchase price.

	(in millions)
Proceeds from borrowings under the Revolving Credit Facility	$ 1,012
Reclassify debt issuance fees recorded in historical balance sheet (1)	(2)
Net adjustment to long-term debt	$ 1,010

(1) Recorded in Other assets in CenterPoint Energy's historical balance sheet as there is no outstanding debt under the Revolving Credit Facility as of June 30, 2018.

(j) *Deferred income taxes*. Reflects additional estimated deferred income taxes attributable to the fair value adjustments of the acquired assets and liabilities, excluding goodwill. Adjustment is based on the combined company's estimated post-Vectren Merger composite statutory tax rate of 23.9% as of June 30, 2018. The assumed statutory tax rate does not take into account any possible future tax events that may impact the combined company.

	(in millions)
Elimination of Vectren's deferred tax liability	$ (501)
Deferred tax liability—fair value	516
Net adjustment to deferred tax liability	$ 15

(k) *Series A Preferred Stock*. Reflects the issuance of Series A Preferred Stock to finance a portion of the Vectren Merger purchase price.

	(in millions)
Proceeds from issuance of Series A Preferred Stock	$ 500
Series A Preferred Stock issuance fees	(8)
Net adjustment to additional paid-in-capital (1)	$ 492

(1) The adjustment to record the issuance of Series A Preferred Stock reflects 500,000 shares at par value of $0.01 per share to Series A Preferred Stock and $492 million to Additional Paid-in-Capital on the pro forma balance sheet.

(l) *Equity.* Reflects the elimination of Vectren's historical equity balances, inclusive of pro forma adjustments to retained earnings recorded by Vectren prior to the close of the Vectren Merger.

	(in millions)
Elimination of Vectren's historical common stock	$ (739)
Elimination of Vectren's historical retained earnings	(1,124)
Elimination of impact to retained earnings of pro forma adjustment Note 4(e)	43
Elimination of impact to retained earnings of pro forma adjustment Note 4(f)	41
Net adjustment to retained earnings	(1,040)
Elimination of Vectren's historical accumulated comprehensive loss	1
Net adjustment to shareholders' equity	$ (1,778)

(5) Adjustments to Pro Forma Statements of Income

(a) *Interest and other finance charges.* Reflects additional interest expense and amortization of debt issuance costs related to the assumed financing transactions described in Note 3 above.

	Six months ended June 30, 2018	Year ended December 31, 2017
	(in millions)	
Estimated interest expense related to Bridge Facility (1)	$ (119)	$ (239)
Amortization of Bridge Facility debt issuance fees (2)	(16)	(31)
Elimination of CenterPoint Energy's historical amortization of Bridge Facility fees	7	—
Estimated interest expense related to Revolving Credit Facility (3)	(18)	(36)
Amortization of Revolving Credit Facility issuance fees (2)	(1)	(1)
Net adjustments to interest and other finance charges	$ (147)	$ (307)

(1) An increase or decrease of one-eighth percent to the assumed interest rate would increase or decrease interest expense by approximately $3 million for the six months ended June 30, 2018 and by approximately $5 million for the year ended December 31, 2017.

(2) Reflects total debt issuance fees of $47 million and $2 million on the Bridge Facility and Revolving Credit Facility, respectively, amortized on a straight-line basis over 18 months.

(3) An increase or decrease of one-eighth percent to the assumed interest rate would increase or decrease interest expense by approximately $1 million for the six months ended June 30, 2018 and by approximately $2 million for the year ended December 31, 2017.

(b) *Depreciation and amortization.* Reflects the amortization expense (benefit) related to the preliminary purchase accounting adjustments for estimated intangible assets and regulatory assets not earning a return, calculated on a straight-line basis over the estimated weighted average useful lives.

	Weighted Average Useful Lives	Six months ended June 30, 2018	Year ended December 31, 2017
		(in millions)	
Eliminate Vectren's historical amortization of intangible assets		$ (1)	$ (3)
Operation and maintenance agreements	9	3	5
Backlog (1)	1	—	—
Customer relationships	3	12	24
Regulatory assets not earning a return	12	(4)	(9)
Net adjustment to depreciation and amortization		$ 10	$ 17

(1) Amortization expense related to backlog amounts has not been included as the weighted average useful life has been estimated at one year and therefore will not have a continuing impact on the combined results.

(c) Reflects the accumulated dividends from the issuance of the Series A Preferred Stock of $15 million and $30 million for the six months ended June 30, 2018, and the year ended December 31, 2017, respectively. A change of 1% in the dividend rate of the $500 million of Series A Preferred Stock would increase or decrease the annual dividend amount by approximately $5 million.

(d) Reflects the elimination of non-recurring transaction costs of $26 million and $10 million related to the Vectren Merger incurred by CenterPoint Energy and Vectren, respectively, and included in the historical income statements for the six months ended June 30, 2018. No such amounts were incurred by CenterPoint Energy or Vectren during the twelve months ended December 31, 2017.

(e) Reflects the income tax effects of the pro forma adjustments calculated using an estimated statutory income tax rate of 23.9% as of June 30, 2018, for the combined company. The assumed statutory tax rate does not take into account any possible future tax events that may impact the combined company.

(6) Reclassification Adjustments

CenterPoint Energy has completed a preliminary review of the financial statement presentation of Vectren for purposes of the unaudited pro forma condensed combined financial statements. During this review, the following financial statement reclassifications were performed in order to align the presentation of Vectren's financial information with that of CenterPoint Energy:

	As of June 30, 2018			
	Vectren Historical As Reported	Reclassification Adjustments	Vectren Historical As Adjusted	CenterPoint Energy Line Item
		(in millions)		
Current Assets:				**Current Assets:**
Cash and cash equivalents	$ 10	$ —	$ 10	Cash and cash equivalents
Accounts receivable, less reserves	232	—	232	Accounts receivable, less bad debt reserve
Accrued unbilled revenues	148	—	148	Accrued unbilled revenues
Inventories	104	(53)	51	Natural gas and fuel inventory
		53	53	Materials and supplies
Recoverable fuel & natural gas costs	10	(10)	—	
Prepaid expenses & other current assets	43	10	53	Prepaid expenses and other current assets
Total current assets	547	—	547	Total current assets
Net utility plant	4,444	479	4,923	**Property, Plant and Equipment, net**
Other Assets:				**Other Assets:**
Investment in unconsolidated affiliate	2	—	2	Investment in unconsolidated affiliate
Other utility & corporate investments	45	(45)	—	
Other nonutility investments	10	(10)	—	
Nonutility plant - net	479	(479)	—	
Goodwill	293	—	293	Goodwill
Regulatory assets	441	—	441	Regulatory assets
	—	30	30	Intangible assets
Other assets	35	25	60	Other
Total other assets	1,305	(479)	826	Total other assets
Total Assets	$ 6,296	$ —	$ 6,296	**Total Assets**

	As of June 30, 2018			
	Vectren Historical As Reported	Reclassification Adjustments	Vectren Historical As Adjusted	CenterPoint Energy Line Item
Current Liabilities:		(in millions)		**Current Liabilities:**
Accounts payable	$ 225	$ —	$ 225	Accounts payable
Accrued liabilities	231	(186)	45	Taxes accrued
		19	19	Interest accrued
		167	167	Other
Short-term borrowings	248	—	248	Short-term borrowings
Current maturities of long-term debt	60	—	60	Current portion of other long-term debt
Total current liabilities	764	—	764	Total current liabilities
Deferred Credits & Other Liabilities:				**Other Liabilities:**
Deferred income taxes	501	—	501	Deferred income taxes, net
Regulatory liabilities	943	—	943	Regulatory liabilities
Deferred credits & other liabilities	297	(151)	146	Other
		151	151	Benefit obligations
Total other liabilities	1,741	—	1,741	Total other liabilities
Long-term Debt - Net of Current Maturities	1,929	—	1,929	Other long-term debt, net
Common Shareholders' Equity:				**Shareholders' Equity:**
Common stock (no par value)	739	—	739	Common stock
Retained earnings	1,124	—	1,124	Retained earnings
Accumulated other comprehensive loss	(1)	—	(1)	Accumulated other comprehensive loss
Total shareholders' equity	1,862	—	1,862	Total shareholders' equity
Total Liabilities and Shareholders' Equity	$ 6,296	$ —	$ 6,296	**Total Liabilities and Shareholders' Equity**

	Six Months Ended June 30, 2018			
	Vectren Historical As Reported	Reclassification Adjustments	Vectren Historical As Adjusted	CenterPoint Energy Line Item
		(in millions)		
Operating Revenues:				**Revenues:**
Gas utility	$ 479	$ 277	$ 756	Utility revenues
Electric utility	277	(277)	—	
Non-utility	547	—	547	Non-utility revenues
Total operating revenues	1,303	—	1,303	Total
Operating Expenses:				**Expenses:**
Cost of gas sold	187	90	277	Utility natural gas, fuel and purchased power
Cost of fuel & purchased power	90	(90)	—	
Cost of nonutility revenues	178	—	178	Non-utility cost of revenues, including natural gas
Other operating	513	15	528	Operation and maintenance
Merger-related	15	(15)	—	
Depreciation & amortization	144	—	144	Depreciation and amortization
Taxes other than income taxes	36	—	36	Taxes other than income taxes
Total operating expenses	1,163	—	1,163	Total
Operating Income	140	—	140	**Operating Income**
Other Income:				**Other Income (Expense):**
Equity in (losses) of unconsolidated affiliates	(18)	—	(18)	Equity in earnings of unconsolidated affiliate, net
Other income - net	19	(15)	4	Other, net
Total other income	1	(15)	(14)	
Interest Expense	47	(15)	32	Interest and other finance charges
Income Before Income Taxes	94	—	94	**Income Before Income Taxes**
Income taxes	8	—	8	Income tax expense
Net Income and Comprehensive Income	$ 86	$ —	$ 86	**Net Income**

	Year Ended December 31, 2017			
	Vectren Historical As Reported	Reclassification Adjustments	Vectren Historical As Adjusted	CenterPoint Energy Line Item
		(in millions)		
Operating Revenues:				**Revenues:**
Gas utility	$ 813	$ 569	$ 1,382	Utility revenues
Electric utility	569	(569)	—	
Non-utility	1,275	—	1,275	Non-utility revenues
Total operating revenues	2,657	—	2,657	Total
Operating Expenses:				**Expenses:**
Cost of gas sold	272	172	444	Utility natural gas, fuel and purchased power
Cost of fuel & purchased power	172	(172)	—	
Cost of nonutility revenues	444	—	444	Non-utility cost of revenues, including natural gas
Other operating	1,116	—	1,116	Operation and maintenance
Depreciation & amortization	276	—	276	Depreciation and amortization
Taxes other than income taxes	59	—	59	Taxes other than income taxes
Total operating expenses	2,339	—	2,339	Total
Operating Income	318	—	318	**Operating Income**
Other Income:				**Other Income (Expense):**
Equity in (losses) of unconsolidated affiliates	(1)	—	(1)	Equity in earnings of unconsolidated affiliate, net
Other income - net	33	(26)	7	Other, net
Total other income	32	(26)	6	
Interest Expense	88	(26)	62	Interest and other finance charges
Income Before Income Taxes	262	—	262	**Income Before Income Taxes**
Income taxes	46	—	46	Income tax expense
Net Income and Comprehensive Income	$ 216	$ —	$ 216	**Net Income**