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 12, 2019

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))

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, $0.01 par value	**CNP**	**New York Stock Exchange** **Chicago Stock Exchange, Inc.**
Depositary shares for 1/20 of 7.00% Series B Mandatory Convertible Preferred Stock, $0.01 par value	**CNP/PB**	**New York Stock Exchange**

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.

As previously reported, on February 1, 2019, pursuant to the Agreement and Plan of Merger (the "Merger Agreement"), dated as of April 21, 2018, by and among CenterPoint Energy, Inc. ("CenterPoint Energy"), Vectren Corporation, an Indiana corporation ("Vectren"), and Pacer Merger Sub, Inc., an Indiana corporation and wholly owned subsidiary of CenterPoint Energy ("Merger Sub"), CenterPoint Energy, Vectren and Merger Sub consummated the previously announced agreement to merge Merger Sub with and into Vectren (the "Merger"), with Vectren continuing as the surviving corporation and as a wholly owned subsidiary of CenterPoint Energy.

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 of Vectren as of December 31, 2018 and 2017, and for the years ended December 31, 2018, 2017 and 2016, and the notes related thereto and the related Independent Auditor's Report, are attached hereto as Exhibit 99.1 and are incorporated by reference herein.

(b) *Pro Forma Financial Information*

The unaudited pro forma condensed combined financial information relating to the Merger is attached hereto as Exhibit 99.2 and is incorporated by reference herein.

(d) *Exhibits*

EXHIBIT NUMBER	EXHIBIT DESCRIPTION
23.1	Consent of Deloitte & Touche LLP
99.1	Audited consolidated financial statements of Vectren Corporation as of December 31, 2018 and 2017, and for the years ended December 31, 2018, 2017 and 2016 and the notes related thereto and the related Independent Auditor's Report
99.2	Unaudited pro forma condensed combined financial information relating to the Merger
104	Cover Page Interactive Data File – the cover page XBRL tags are embedded within the Inline XBRL document.

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 12, 2019

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

Exhibit 23.1

CONSENT OF INDEPENDENT AUDITORS

We consent to the incorporation by reference in Registration Statement No. 333-215833 (including Post-Effective Amendment No. 1 thereto) on Form S-3; Registration Statement Nos. 333-203201, as amended, 333-179310, 333-173660, 333-149757, 333-101202, as amended, 333-115976, as amended, 333-159586, as amended, and 333-105773, as amended on Form S-8; Post-Effective Amendment No. 1 to Registration Statement Nos. 333-32413-99, 333-49333-99, 333-38188-99, 333-60260-99 and 333-98271-99 on Form S-8; and Post-Effective Amendment No. 5 to Registration Statement No. 333-11329-99 on Form S-8 of CenterPoint Energy, Inc. of our report dated February 27, 2019, relating to the consolidated financial statements of Vectren Corporation and subsidiary companies appearing in this Current Report on Form 8-K of CenterPoint Energy, Inc. dated August 12, 2019.

DELOITTE & TOUCHE LLP
Indianapolis, IN
August 12, 2019

Exhibit 99.1

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED FINANCIAL STATEMENTS

For the year ended December 31, 2018

Contents

Deloitte & Touche LLP
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INDEPENDENT AUDITORS' REPORT

To the Director of Vectren Corporation:

We have audited the accompanying consolidated financial statements of Vectren Corporation and its subsidiaries (the "Company"), which comprise the consolidated balance sheets as of December 31, 2018 and 2017, and 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, 2018, and the related notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Vectren Corporation and its subsidiaries as of December 31, 2018 and 2017, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2018, in accordance with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

February 27, 2019

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

	At December 31, 2018	At December 31, 2017
ASSETS		
Current Assets		
Cash & cash equivalents	$ 29.6	$ 16.6
Accounts receivable - less reserves of $4.5 & $5.1, respectively	241.3	262.9
Accrued unbilled revenues	182.6	207.1
Inventories	106.8	126.6
Recoverable fuel & natural gas costs	6.9	19.2
Prepayments & other current assets	54.1	47.0
Total current assets	**621.3**	**679.4**
Utility Plant		
Original cost	7,528.4	7,015.4
Less: accumulated depreciation & amortization	2,891.7	2,738.7
Net utility plant	**4,636.7**	**4,276.7**
Investments in unconsolidated affiliates	1.4	19.7
Other utility & corporate investments	43.6	43.7
Other nonutility investments	9.6	9.6
Nonutility plant - net	476.3	464.1
Goodwill	293.5	293.5
Regulatory assets	478.9	416.8
Other assets	34.1	35.8
TOTAL ASSETS	**$6,595.4**	**$6,239.3**

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, 2018	At December 31, 2017
LIABILITIES & SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 268.7	$ 366.2
Accrued liabilities	253.7	222.3
Short-term borrowings	166.6	249.5
Current maturities of long-term debt	60.0	100.0
Total current liabilities	**749.0**	**938.0**
Long-term Debt - Net of Current Maturities	2,154.1	1,738.7
Deferred Credits & Other Liabilities		
Deferred income taxes	528.0	491.3
Regulatory liabilities	941.3	937.2
Deferred credits & other liabilities	319.6	284.8
Total deferred credits & other liabilities	**1,788.9**	**1,713.3**
Commitments & Contingencies (Notes 6, 15-18)		
Common Shareholders' Equity		
Common stock (no par value) - issued & outstanding 83.1 & 83.0 shares, respectively	739.5	736.9
Retained earnings	1,165.2	1,113.7
Accumulated other comprehensive (loss)	(1.3)	(1.3)
Total common shareholders' equity	**1,903.4**	**1,849.3**
TOTAL LIABILITIES & SHAREHOLDERS' EQUITY	**$6,595.4**	**$6,239.3**

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,		
	2018	2017	2016
OPERATING REVENUES			
Gas utility	$ 857.8	$ 812.7	$ 771.7
Electric utility	582.5	569.6	605.8
Nonutility	1,253.0	1,275.0	1,070.8
Total operating revenues	**2,693.3**	**2,657.3**	**2,448.3**
OPERATING EXPENSES			
Cost of gas sold	316.7	271.5	266.7
Cost of fuel & purchased power	186.2	171.8	183.6
Cost of nonutility revenues	404.7	444.2	363.4
Other operating	1,082.4	1,114.8	933.3
Merger-related	31.5	—	—
Depreciation & amortization	292.2	276.2	260.0
Taxes other than income taxes	66.7	59.3	60.9
Total operating expenses	**2,380.4**	**2,337.8**	**2,067.9**
OPERATING INCOME	**312.9**	**319.5**	**380.4**
OTHER INCOME			
Equity in earnings (losses) of unconsolidated affiliates	(18.3)	(1.1)	(0.2)
Other income – net	36.1	31.7	29.8
Total other income	17.8	30.6	29.6
Interest expense	97.4	87.7	85.5
INCOME BEFORE INCOME TAXES	**233.3**	**262.4**	**324.5**
Income taxes	28.7	46.4	112.9
NET INCOME	**$ 204.6**	**$ 216.0**	**$ 211.6**
WEIGHTED AVERAGE AND DILUTED COMMON SHARES OUTSTANDING	**83.1**	**83.0**	**82.8**
BASIC AND DILUTED EARNINGS PER SHARE OF COMMON STOCK	**$ 2.46**	**$ 2.60**	**$ 2.55**

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,		
	2018	2017	2016
NET INCOME	**$204.6**	**$216.0**	**$211.6**
Pension & other benefits			
Amounts arising during the year	(7.7)	(5.6)	(10.1)
Reclassifications to periodic cost	6.7	5.4	4.7
Deferrals to regulatory assets	1.0	0.2	5.3
Pension & other benefits costs	**—**	**—**	**(0.1)**
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX	**—**	**—**	**(0.1)**
TOTAL COMPREHENSIVE INCOME	**$204.6**	**$216.0**	**$211.5**

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,		
	2018	2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 204.6	$ 216.0	$ 211.6
Adjustments to reconcile net income to cash from operating activities:			
Depreciation & amortization	292.2	276.2	260.0
Deferred income taxes & investment tax credits	26.6	19.0	100.1
Provision for uncollectible accounts	7.1	5.9	6.9
Expense portion of pension & postretirement benefit cost	4.3	5.4	3.6
Other non-cash items - net	21.1	12.9	7.8
Changes in working capital accounts:			
Accounts receivable & accrued unbilled revenues	39.0	(80.9)	(39.6)
Inventories	19.8	3.3	3.9
Recoverable/refundable fuel & natural gas costs	12.3	10.7	(37.8)
Prepayments & other current assets	(7.2)	5.7	22.9
Accounts payable, including to affiliated companies	(103.9)	65.9	40.7
Accrued liabilities	31.1	15.6	22.7
Employer contributions to pension & postretirement plans	(8.5)	(4.6)	(19.6)
Changes in noncurrent assets	(34.6)	(40.6)	(44.0)
Changes in noncurrent liabilities	(14.1)	(11.7)	(15.1)
Net cash from operating activities	**489.8**	**498.8**	**524.1**
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from:			
Long-term debt, net of issuance costs	474.3	198.5	—
Dividend reinvestment plan & other common stock issuances	1.7	6.3	6.3
Requirements for:			
Dividends on common stock	(152.0)	(141.9)	(134.2)
Retirement of long-term debt	(100.0)	(75.0)	(73.0)
Net change in short-term borrowings	(82.9)	55.1	179.9
Net cash from financing activities	**141.1**	**43.0**	**(21.0)**
CASH FLOWS FROM INVESTING ACTIVITIES			
Proceeds from sale of assets and other collections	6.7	11.3	33.0
Requirements for:			
Capital expenditures, excluding AFUDC equity	(624.6)	(602.6)	(542.0)
Other costs	—	(3.4)	(5.2)
Changes in restricted cash	—	0.9	5.0
Net cash from investing activities	**(617.9)**	**(593.8)**	**(509.2)**
Net change in cash & cash equivalents	13.0	(52.0)	(6.1)
Cash & cash equivalents at beginning of period	16.6	68.6	74.7
Cash & cash equivalents at end of period	$ 29.6	$ 16.6	$ 68.6

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			Accumulated Other	
	Shares	Amount	Retained Earnings	Comprehensive Income (Loss)	Total
Balance at January 1, 2016	**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: option exercises & 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**
Net income			204.6		204.6
Other comprehensive income (loss)					—
Common stock:					
Issuance: dividend reinvestment plan	0.1	1.7			1.7
Dividends ($1.830 per share)			(152.0)		(152.0)
Other		0.9	(1.1)		(0.2)
Balance at December 31, 2018	**83.1**	**$739.5**	**$1,165.2**	**$ (1.3)**	**$1,903.4**

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 599,200 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 146,300 electric customers and approximately 111,900 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to approximately 320,100 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.

<u>Merger with CenterPoint Energy, Inc.</u>

On February 1, 2019, Vectren completed the previously announced merger with CenterPoint Energy, Inc., a Texas corporation ("CenterPoint"). In accordance with the Merger Agreement, a wholly owned subsidiary of CenterPoint merged with and into the Company (the "Merger"), with the Company surviving as a wholly owned subsidiary of CenterPoint. The Company's shareholders received $72.00 plus a dividend of $0.41145 in cash for each share of common stock. In addition, all unvested share based compensation awards became fully vested upon close of the transaction, and were either paid out in cash or deferred into a deferred compensation plan. The total purchase price was approximately $6 billion.

In connection with this transaction, the Company has recorded Merger-related expenses of $31.5 million for the year ending December 31, 2018, which are reflected in *Merger-related* in *Operating Expenses* in the Consolidated Statements of Income. Merger-related expenses for the year included $24.4 million of transaction advisory and other costs and $7.1 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 accounted for these costs as tax deductible since the requisite closing conditions to the Merger were not satisfied at December 31, 2018. While the merger has been completed, the Company continues to evaluate the tax deductibility of these costs and will reflect any non-deductible amounts in the effective tax rate at the Merger closing date. Subsequent to year end, the Company has incurred approximately another $100 million of Merger-related expenses including transaction advisory and other costs, share-based compensation costs that resulted from the accelerated vesting of awards, and severance and other employee change in control costs.

The Merger was subject to the approvals, orders, or waivers of various government agencies, including the FERC, Federal Communications Commission, Federal Trade Commission, the IURC, and PUCO. Approvals were obtained from all agencies subject to several conditions. The Company does not believe that the conditions set forth in the various regulatory orders approving the Merger will have a material impact on its operations or financial results.

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. The Company's management has performed a review of subsequent events through February 27, 2019, the date the financial statements were 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 is 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* are 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 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 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 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 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 service cost of all postretirement plans is recognized in operating expenses or capitalized to plant following the direct labor of current employees. Non-service costs are expensed as incurred and included in *Other income - net*. 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 electric 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

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.

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.

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 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 \$31.1 million in 2018, \$29.1 million in 2017, and \$28.3 million in 2016. 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. 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 January 1, 2018 consolidated 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 Consolidated Income Statement for the year ended December 31, 2018 and the Consolidated Balance Sheet as of December 31, 2018. 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.

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 20, 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 monthly 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)	Year Ended December 31, 2018
Gas Utility Services	
Residential	$ 575.2
Commercial	196.6
Industrial	78.3
Other	7.7
Total Gas Utility Services	$ 857.8
Electric Utility Services	
Residential	$ 210.2
Commercial	149.3
Industrial	162.1
Other	60.9
Total Electric Utility Services	$ 582.5

Infrastructure Services

Infrastructure Services provides underground pipeline construction and repair services. The duration of the contracts is 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)	Year Ended December 31, 2018
Revenue	
Unit or time and material (point in time)	$ 628.5
Fixed price (over time)	337.2
Total Infrastructure Services	$ 965.7

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 15.

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

(In millions)	Year Ended December 31, 2018
Revenue	
Construction	$ 260.8
Operations and maintenance and other	30.5
Total Energy Services	$ 291.3

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 assets are included in *Accrued unbilled revenues* in the Consolidated Balance Sheets. The Company's contract assets primarily relate to contracts in the Infrastructure Services segment where revenue is recognized using the input method. The Company's contract liabilities are included in *Accrued Liabilities* in the 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 opening and closing balances of the Company's accounts receivable, accrued unbilled revenue, and contract liabilities are as follows:

(In millions)	Accounts Receivable	Other Accrued Unbilled Revenues	Contract Assets	Contract Liabilities
Opening (01/01/2018)	$ 262.9	$ 168.3	$ 31.8	$ 38.3
Closing (12/31/2018)	241.3	161.1	21.5	40.3
Increase/(decrease)	$ (21.6)	$ (7.2)	$ (10.3)	$ 2.0

The full amount of the opening contract liabilities has been recognized in revenue in year ended December 31, 2018. The differences between the opening and closing balances of the Company's contracts assets and contract liabilities primarily result from timing differences 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)	Less than 12 Months	12 Months or Greater	Total
Revenue expected to be recognized on contracts in place as of December 31, 2018:			
Energy Services - operations and maintenance	$ 30.7	$ 383.9	$ 414.6
Energy Services - construction	213.3	67.8	281.1
Infrastructure Services - fixed price (bid)	344.8	—	344.8
Total	$ 588.8	$ 451.7	$1,040.5

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. 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, 2018		2017	
	Original Cost	Depreciation Rates as a Percent of Original Cost	Original Cost	Depreciation Rates as a Percent of Original Cost
Gas utility plant	$ 4,315.3	3.4%	$ 3,969.6	3.4%
Electric utility plant	2,945.8	3.3%	2,833.5	3.3%
Common utility plant	67.6	3.2%	59.0	3.2%
Construction work in progress	112.6	—	70.7	—
Asset retirement obligations	87.1	—	82.6	—
Total original cost	**$ 7,528.4**		**$ 7,015.4**	

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, 2018, is $192.1 million with accumulated depreciation totaling $128.5 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:

	At December 31,	
(In millions)	2018	2017
Vehicles & equipment	$230.3	$220.2
Computer hardware & software	165.0	156.5
Land & buildings	65.3	77.1
All other	15.7	10.3
Nonutility plant - net	**$476.3**	**$464.1**

Nonutility Plant is presented net of accumulated depreciation and amortization of $539.1 million and $506.9 million as of December 31, 2018 and 2017, respectively. Depreciable lives range from 5 to 15 years for vehicles and equipment, 6 to 15 years for computer hardware & software, and 30 to 40 years for buildings. The Company capitalized interest totaling $1.2 million for both years ended December 31, 2018 and 2017.

5. Regulatory Assets & Liabilities

Regulatory Assets

Regulatory assets consist of the following:

	At December 31,	
(In millions)	2018	2017
Future amounts recoverable from ratepayers related to:		
Benefit obligations (See Note 9)	$103.8	$102.8
Net deferred income taxes (See Note 8)	6.6	6.2
Asset retirement obligations & other	34.4	24.3
	144.8	133.3
Amounts deferred for future recovery related to:		
Indiana cost recovery riders	97.5	70.0
Ohio cost recovery riders	107.9	72.4
	205.4	142.4
Amounts currently recovered in customer rates related to:		
Indiana authorized trackers	67.2	75.9
Ohio authorized trackers	33.0	28.4
Loss on reacquired debt & hedging costs	21.4	22.7
Deferred coal costs and other	7.1	14.1
	128.7	141.1
Total regulatory assets	**$478.9**	**$416.8**

Of the $129 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 $21 million, is 19 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 9.

Regulatory assets for asset retirement obligations, see Note 18 for further discussion, 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, 2018 and 2017, the Company had regulatory liabilities of approximately $941 million and $937 million, respectively, of which $502 million and $477 million related to cost of removal obligations and $438 million and $459 million related to deferred taxes, at December 31, 2018 and 2017, respectively. The deferred tax related regulatory liability is primarily the revaluation of deferred taxes at the reduced federal corporate tax rate that was enacted on December 22, 2017. These regulatory liabilities are being refunded to customers over time following regulatory commission approval.

6. 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, 2018, shown at its 61 percent ownership share of the individual net assets of ProLiance, is as follows.

(In millions)	As of December 31, 2018
Cash	$ 0.1
Investment in LA Storage	4.9
Total investment in ProLiance	$ 5.0
Included in:	
Investments in unconsolidated affiliates	$ 0.6
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 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. At December 31, 2018 and 2017, ProLiance's investment in the joint venture was $8.0 million and $36.8 million, respectively.

7. Intangible Assets

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

(In millions)	At December 31,			
	2018		2017	
	Amortizing	Non-amortizing	Amortizing	Non-amortizing
Customer-related assets	$ 16.4	$ —	$ 18.6	$ —
Market-related assets	6.3	6.0	6.6	6.0
Intangible assets, net	**$ 22.7**	**$ 6.0**	**$ 25.2**	**$ 6.0**

As of December 31, 2018, the weighted average remaining life for amortizing customer-related assets is 12 years. These amortizing intangible assets have no significant residual values. Intangible assets are presented net of accumulated amortization totaling $17.2 million for customer-related assets and $4.5 million for market-related assets at December 31, 2018 and $14.6 million for customer-related assets and $4.3 million for market-related assets at December 31, 2017. Annual amortization associated with intangible assets totaled $2.6 million in 2018, $2.6 million in 2017 and $2.5 million in 2016. Amortization should approximate (in millions) $2.6 per year from 2019 through 2023. 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 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.

Consolidated results reflected 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 resulted in $333.4 million in excess federal deferred income taxes for the Utility Group for the period ending December 31, 2017, resulting in a regulatory liability of $458.6 million after gross-up.

The Company's gas and electric utilities currently recover corporate income tax expense in 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 liabilities to record all estimated impacts of tax reform starting January 1, 2018. As of December 31, 2018, the Company has established $39.1 million in liabilities associated with the other impacts of tax reform, including $10.3 million in *Regulatory Liabilities* and $28.8 million in *Accrued Liabilities.*

In Indiana, 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. The refund of excess deferred taxes and regulatory liabilities commenced in November 2018 for the Company's Indiana electric customers and in January 2019 for the Company's Indiana gas customers.

In Ohio, the initial rate reduction to the Company's current rates and charges will be effective upon conclusion of its pending base rate case filed on March 30, 2018. In January 2019, the Company filed an application with PUCO requesting authority to implement a rider to flow back to customers the tax benefits realized under the TCJA, including the refund of excess deferred taxes and regulatory liabilities.

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

	Year Ended December 31,		
	2018	2017	2016
Statutory rate:	21.0%	35.0%	35.0%
Federal tax law change impacts	(7.6)	(17.3)	—
State & local taxes-net of federal benefit	3.4	3.4	2.8
Energy efficiency building deductions	(2.2)	(0.8)	(1.7)
All other-net	(2.3)	(2.6)	(1.3)
Effective tax rate	**12.3%**	**17.7%**	**34.8%**

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. The impacts were reflected in 2018 results related to accounting for retroactive effects of legislation.

Significant components of the net deferred tax liability follow:

	At December 31,	
(In millions)	2018	2017
Noncurrent deferred tax liabilities (assets):		
Depreciation & cost recovery timing differences	$ 619.2	$ 593.7
Regulatory assets recoverable through future rates	8.1	7.9
Alternative minimum tax carryforward	—	(12.2)
Employee benefit obligations	(17.7)	(9.3)
Net operating loss & other carryforwards (net of valuation allowances)	(5.8)	(4.1)
U.S. federal charitable contributions carryforwards	(8.8)	(12.2)
Regulatory liabilities to be settled through future rates	(104.6)	(116.2)
Impairments	(5.2)	(0.6)
Deferred fuel costs-net	14.4	16.2
Other – net	28.4	28.1
Net noncurrent deferred tax liability	**$ 528.0**	**$ 491.3**

At December 31, 2018 and 2017, investment tax credits totaling $3.4 million and $1.2 million respectively, are included in *Deferred credits & other liabilities*.

In addition, the Company has $14.1 million in state net operating losses and $8.8 million and $1.1 million in federal and state charitable contribution carryforwards, respectively, 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, 2018, the valuation allowance on the state net operating losses and federal and state charitable contribution carryforwards was $9.9 million.

The components of income tax expense follow:

(In millions)	Year Ended December 31, 2018	2017	2016
Current:			
Federal	$14.1	$20.5	$ 6.8
State	5.3	6.9	6.0
Total current taxes	**19.4**	**27.4**	**12.8**
Deferred:			
Federal	6.1	16.7	97.6
State	(0.2)	2.7	3.6
Total deferred taxes	**5.9**	**19.4**	**101.2**
Net investment tax credit deferred / (amortized)	3.4	(0.4)	(1.1)
Total income tax expense	**$28.7**	**$46.4**	**$112.9**

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 $1.7 million and $1.3 million, respectively, at December 31, 2018 and 2017.

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) is currently examining the Company's U.S. federal income tax return for tax year December 31, 2016. The State of Indiana, the Company's primary state tax jurisdiction, is currently examining the Company's consolidated state returns for December 31, 2015 through 2017 and has previously concluded examinations of state income tax returns for tax years through December 31, 2011. The statutes of limitations for assessment of federal income tax and Indiana income tax have expired with respect to tax years through 2015 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 tax return will expire in 2020. The statutes of limitations for assessment of the 2012 through 2014 tax years related to the amended Indiana income tax returns will expire in 2019 through 2020.

9. Retirement Plans & Other Postretirement Benefits

At December 31, 2018, 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, 2018 follows:

	Pension Benefits			Other Benefits		
(In millions)	2018	2017	2016	2018	2017	2016
Service cost	$ 6.7	$ 6.5	$ 7.0	$ 0.2	$ 0.2	$ 0.3
Interest cost	12.8	13.7	14.7	1.4	1.5	1.7
Expected return on plan assets	(21.1)	(21.0)	(22.8)	—	—	—
Amortization of prior service cost (benefit)	0.5	0.4	0.4	(2.2)	(2.4)	(2.9)
Amortization of actuarial loss	8.4	7.4	7.2	—	—	—
Settlement charge	1.7	2.1	—	—	—	—
Net periodic benefit cost (benefit)	**$ 9.0**	**$ 9.1**	**$ 6.5**	**$(0.6)**	**$(0.7)**	**$(0.9)**

A portion of the service cost disclosed in the table above is capitalized as *Utility Plant* following the allocation of current employee labor costs. Service costs capitalized in 2018, 2017, and 2016 are estimated at $2.6 million, $3.0 million, and $1.9 million, respectively.

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

	Pension Benefits			Other Benefits		
	2018	2017	2016	2018	2017	2016
Discount rate	3.61%	4.07%	4.31%	3.57%	4.04%	4.21%
Rate of compensation increase	3.50%	3.50%	3.50%	N/A	N/A	N/A
Expected return on plan assets	7.00%	7.00%	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 derives its discount rate by identifying a theoretical settlement portfolio of high quality corporate bonds sufficient to provide for the plans' projected benefit payments. The Company uses a "building block" approach to develop an expected long-term rate of return. 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, 2018 and 2017 follows:

	Pension Benefits		Other Benefits	
(In millions)	2018	2017	2018	2017
Projected benefit obligation, beginning of period	$366.3	$350.4	$40.0	$40.5
Service cost – benefits earned during the period	6.7	6.5	0.2	0.2
Interest cost on projected benefit obligation	12.8	13.7	1.4	1.5
Plan participants' contributions	—	—	1.2	1.2
Plan amendments	0.4	1.4	—	—
Actuarial loss (gain)	(27.3)	25.4	(1.7)	1.3
Settlement loss	1.5	0.5	—	—
Benefit payments	(33.3)	(31.4)	(5.0)	(4.7)
Projected benefit obligation, end of period	**$327.1**	**$366.5**	**$36.1**	**$40.0**

The accumulated benefit obligation for all defined benefit pension plans was $319.1 million and $356.5 million at December 31, 2018 and 2017, 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, 2018 and 2017 was calculated using the following weighted average assumptions:

	Pension Benefits		Other Benefits	
	2018	2017	2018	2017
Discount rate	4.27%	3.61%	4.24%	3.57%
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, 2018, the assumptions for determining future lump sum payments reflect the latest IRS mortality table (2019) and the latest mortality improvement scales released by the Society of Actuaries. To calculate the 2018 ending postretirement benefit obligation, medical claims costs in 2019 were assumed to be 6.7 percent higher than those incurred in 2018. 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 less than $0.2 million.

Plan Assets

A reconciliation of the Company's plan assets at December 31, 2018 and 2017 follows:

(In millions)	Pension Benefits		Other Benefits	
	2018	2017	2018	2017
Plan assets at fair value, beginning of period	$316.1	$304.5	$—	$—
Actual return on plan assets	(15.4)	41.9	—	—
Employer contributions	4.6	1.1	3.9	3.5
Plan participants' contributions	—	—	1.1	1.2
Benefit payments	(33.3)	(31.4)	(5.0)	(4.7)
Fair value of plan assets, end of period	**$272.0**	**$316.1**	**$—**	**$—**

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 (NAV) of the underlying investments which has been used 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, 2018 and December 31, 2017 by asset category and by fair value hierarchy are as follows:

(In millions)	As of December 31, 2018			
	Level 1	Level 2	Level 3	Total
Domestic equity funds	$120.3	$ —	$ —	$120.3
International equity funds	40.1	—	—	40.1
Bond funds	37.4	—	—	37.4
Real estate, commodity & other funds	16.1	—	4.6	20.7
Investments measured at NAV	—	—	—	53.5
Total plan investments	**$213.9**	**$ —**	**$ 4.6**	**$272.0**

(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 NAV	—	—	—	74.8
Total plan investments	**$236.8**	**$ —**	**$ 4.5**	**$316.1**

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, 2018 and 2017, the estimate of undiscounted funds necessary to satisfy John Hancock's remaining obligation was $4.4 million and $4.2 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, 2018 and 2017 was 3.78 percent and 3.25 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)	2018	2017
Fair value, beginning of year	$ 4.5	$ 4.4
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	**$ 4.6**	**$ 4.5**

Funded Status

The funded status of the plans as of December 31, 2018 and 2017 follows:

(In millions)	Pension Benefits 2018	Pension Benefits 2017	Other Benefits 2018	Other Benefits 2017
Qualified Plans				
Projected benefit obligation, end of period	$(306.5)	$(343.4)	$(36.1)	$(40.0)
Fair value of plan assets, end of period	272.0	316.1	—	—
Funded Status of Qualified Plans, end of period	(34.5)	(27.3)	(36.1)	(40.0)
Projected benefit obligation of SERP Plan, end of period	(20.6)	(22.9)	—	—
Total funded status, end of period	**$ (55.1)**	**$ (50.2)**	**$(36.1)**	**$(40.0)**
Accrued liabilities	$ 0.6	$ 1.1	$ 4.7	$ 4.1
Deferred credits & other liabilities	$ 54.5	$ 49.1	$ 31.4	$ 35.9

Expected Cash Flows

The Company expects to make no contributions to the qualified pension plans in 2019. In addition, the Company expects to make contributions totaling approximately $3.0 million into the postretirement plan.

Estimated retiree pension benefit payments, excluding the SERP, projected to be required during the years following 2018 are approximately (in millions) $28.5 in 2019, $27.4 in 2020, $25.4 in 2021, $26.6 in 2022, $26.3 in 2023, and $118.6 in years 2024-2028. Expected benefit payments projected to be required for postretirement benefits during the years following 2018 (in millions) are approximately $4.6 in 2019, $4.9 in 2020, $4.9 in 2021, $4.9 in 2022, $5.0 in 2023, and $21.0 in years 2024-2028.

Subsequent to the February 1, 2019 completion of the Merger, and pursuant to the Merger Agreement, substantially all the SERP liability will be settled during 2019. Approximately $19 million was funded into a rabbi trust in 2019 to fund the settlement.

Prior Service Cost and Actuarial Gains and Losses

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

	Pensions		Other Benefits	
(In millions)	Prior Service Cost	Net (Gain) or Loss	Prior Service Cost	Net (Gain) or Loss
Balance at January 1, 2016	**$ 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**
Amounts arising during the period	0.4	8.9	—	(1.6)
Reclassification to benefit costs	(0.5)	(8.4)	2.2	—
Balance at December 31, 2018	**$ 2.2**	**$110.8**	**$ (6.6)**	**$ (0.4)**

Following is a reconciliation of the amounts in *Accumulated other comprehensive income* (AOCI) and *Regulatory assets* related to retirement plan obligations at December 31, 2018 and 2017.

	2018		2017	
(In millions)	Pensions	Other Benefits	Pensions	Other Benefits
Prior service cost	$ 2.2	$ (6.6)	$ 2.3	$ (8.8)
Unamortized actuarial loss	110.8	(0.4)	110.3	1.2
	113.0	(7.0)	112.6	(7.6)
Less: *Regulatory asset* deferral	(110.7)	6.9	(110.2)	7.4
***AOCI* before taxes**	**$ 2.3**	**$ (0.1)**	**$ 2.4**	**$ (0.2)**

Related to pension plans, $0.5 million of prior service cost and $7.2 million of actuarial loss is expected to be amortized to cost in 2019. Related to other benefits, no actuarial gain/loss is expected to be amortized to periodic cost in 2019, and $2.2 million of prior service cost is expected to reduce costs in 2019.

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 stops participation in some of 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 $43.8 million, $42.1 million and $35.0 million for the years ended December 31, 2018, 2017, and 2016, respectively. During 2018, 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 2019 through 2021. The average contribution related to these local unions was less than $0.2 million, and the largest contribution was $4.0 million. Multiple unions can contribute to a single multiemployer plan. The Company made contributions to at least 50 plans in 2018, 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 2018 and 2017 is for the plan year end at January 31, 2018 and 2017 for the Central Pension Fund, May 31, 2018 and 2017 for the Indiana Laborers Fund, December 31, 2017 and 2016 for the Pipeline Industry Benefit Fund, December 31, 2017 and 2016 for the Laborers District Council & Contractors’ Pension Fund of Ohio, April 30, 2018 and 2017 for the Ohio Operating Engineers Pension Fund, April 30, 2018 and 2017 for the Operating Engineers Local 324 Fringe Benefit Fund, and December 31, 2017 and 2016 for the Minnesota Laborers Pension Fund respectively. 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 2018, 2017, and 2016.

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 Protection Act Zone Status			Multiemployer Contributions			
Pension Fund	EIN/Pension Plan Number	2018	2017	FIP/RP Status Pending/ Implemented	2018	2017	2016	Surcharge Imposed
Central Pension Fund	36-6052390-001	Green	Green	No	$ 9.0	$ 9.3	$ 7.4	No
Indiana Laborers Pension Fund	35-6027150-001	Green	Yellow	Implemented	5.2	5.0	4.4	No
Pipeline Industry Benefit Fund	73-0742835-001	Green	Green	No	4.1	4.9	3.0	No
Laborers District Fund of Ohio	31-6129964-001	Green	Green	No	3.6	3.3	2.0	No
Ohio Operating Engineers Pension Fund	31-6129968-001	Green	Green	No	2.6	2.8	2.1	No
Operating Eng. Local 324 Fund (1)	38-1900637-001	Red	Red	Implemented	2.8	2.5	1.6	No
Minnesota Laborers Pension Fund	41-6159599-001	Green	Green	No	2.0	1.1	1.2	No
Other					14.5	13.2	13.3	
Total Contributions					$43.8	$42.1	$35.0	

(1) The Operating Engineers Local #324 Fringe Benefits Fund was certified to be in “critical” status for the plan year ending April 30, 2018 because the Plan is projected to have an accumulated funding deficiency on April 30, 2019, which is within nine years of the current plan year. In an effort to improve the Plan’s funding situation, on March 17, 2011, the trustees adopted a Plan Amendment, which reduced benefit accruals and eliminated some ancillary benefits, and adopted an RP 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 RP to change the annual standard for meeting the requirements of the RP. 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 four 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 2018, 2017 and 2016, the Company made contributions to these plans of $14.5 million, $13.2 million, and $12.1 million, respectively. Subsequent to the Merger closing, there is no longer an option to invest in Vectren common stock.

10. Borrowing Arrangements

Long-Term Debt

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

(In millions)	At December 31, 2018	2017
Utility Holdings		
Fixed Rate Senior Unsecured Notes		
2018, 5.75%	$ —	$ 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	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	100.0
2055, 4.51%	40.0	40.0
Variable Rate Term Loans		
2020, current adjustable rate, 3.20%	300.0	—
Total Utility Holdings	**$1,400.0**	**$1,200.0**
Indiana Gas		
Fixed Rate Senior Unsecured Notes		
2025, Series E, 6.53%	10.0	10.0
2027, Series E, 6.42%	5.0	5.0
2027, Series E, 6.68%	1.0	1.0
2027, Series F, 6.34%	20.0	20.0
2028, Series F, 6.36%	10.0	10.0
2028, Series F, 6.55%	20.0	20.0
2029, Series G, 7.08%	30.0	30.0
Total Indiana Gas	**$ 96.0**	**$ 96.0**
SIGECO		
First Mortgage Bonds		
2022, 2013 Series C, current adjustable rate 2.75%, tax-exempt	4.6	4.6
2024, 2013 Series D, current adjustable rate 2.75%, tax-exempt	22.5	22.5
2025, 2014 Series B, current adjustable rate 2.75%, tax-exempt	41.3	41.3
2029, 1999 Series, 6.72%	80.0	80.0
2037, 2013 Series E, current adjustable rate 2.75%, tax-exempt	22.0	22.0
2038, 2013 Series A, current adjustable rate 2.75%, tax-exempt	22.2	22.2
2043, 2013 Series B, current adjustable rate 2.75%, 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, 2018	2017
Vectren Capital Corp.		
Fixed Rate Senior Unsecured Notes		
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
Variable Rate Term Loans		
2020, current adjustable rate, 3.14%	175.0	—
Total Vectren Capital Corp.	**$ 435.0**	**$ 260.0**
Total long-term debt outstanding	**$2,223.7**	**$1,848.7**
Current maturities of long-term debt	(60.0)	(100.0)
Debt issuance costs	(9.1)	(9.4)
Debt subject to tender		—
Unamortized debt premium & discount-net	(0.5)	(0.6)
Total long-term debt-net	**$2,154.1**	**$1,738.7**

Term Loans

On July 30, 2018, Utility Holdings closed a two-year term loan with two banking partners. The term loan agreement provided for a $250 million draw at closing and the remaining $50 million was drawn on December 14, 2018. Proceeds from the term loan were utilized to pay a $100 million, August 1, 2018, debt maturity and for general utility purposes. The term loan's interest rate is currently priced at one-month LIBOR, plus a credit spread ranging from 70 to 90 basis points depending on Utility Holdings' credit rating. The current spread is 70 basis points and such spread remains unchanged by recent actions taken by rating agencies. 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.

On September 14, 2018, Vectren Capital Corporation (Vectren Capital), which funds short-term and long-term financing needs of the Nonutility Group and corporate operations, closed a two-year term loan with one banking partner. This term loan agreement provided for a $50 million draw at closing and a $125 million draw on December 14, 2018. Proceeds from the term loan have been utilized for general corporate purposes. The term loan's interest rate is priced at one-month LIBOR, plus a credit spread. In addition, the Vectren Capital term loan contains the same provision as the Utility Holdings' term loan stipulating that should the Company 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 Vectren Corporation. At December 31, 2018, Vectren Capital had remaining firm commitment on the term loan of $25 million. This was drawn on February 8, 2019. The loan also contains a $50 million accordion feature.

Utility Holdings and Vectren Capital Borrowing Arrangements

The Merger constituted a "Change of Control" under the note agreements pursuant to which Senior Notes executed by Utility Holdings in an aggregate principal amount of $1.025 billion and Senior Notes executed by Vectren Capital in an aggregate principal amount of $260 million were issued. At December 31, 2018, the prepayment offer was accepted on $568 million of Utility Holdings notes and $191 million of Vectren Capital notes. At merger close, CenterPoint loaned Utility Holdings and Vectren Capital the proceeds necessary to make the prepayment at the same interest rate and term as the notes being prepaid. The CenterPoint notes are not guaranteed by Utility Holdings' subsidiaries or Vectren Corporation.

Pursuant to the Company's two short-term credit facilities, the Merger represented an event of default. However, the banking partners in these facilities have waived the event of default.

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 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;
- 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.

Mandatory Tenders

At December 31, 2018, certain series of SIGECO bonds, aggregating $185.7 million are subject to mandatory tenders prior to the bonds' final maturities. $38.2 million will be tendered in 2020 and $147.5 million will be tendered in 2023.

Call Options

At December 31, 2018, certain series of SIGECO bonds may be called at SIGECO's option. $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 2018 sinking fund requirement by this means and, expects to also meet this requirement in 2019 in this manner. Accordingly, the sinking fund requirement is excluded from *Current liabilities* in the *Consolidated Balance Sheets*. At December 31, 2018, $1.6 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 $3.6 billion at December 31, 2018.

Consolidated maturities of long-term debt during the five years following 2018 (in millions) are $60 in 2019, $575 in 2020, $55 in 2021, $80 in 2022, $150 in 2023, and $1,294 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, 2018 was $435 million. Vectren Capital had no short-term obligations outstanding at December 31, 2018. 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, 2018 are $1.4 billion and $167 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, 2018, the Company was in compliance with all debt covenants.

Short-Term Borrowings

At December 31, 2018, the Company had $600 million of short-term borrowing capacity, including $400 million for Utility Holdings and $200 million for Vectren Capital. 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. 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. Both Utility Holdings' and Vectren Capital's short-term credit facilities are available through July 14, 2022.

As reduced by borrowings currently outstanding, approximately $233 million was available for the Utility Group operations and $200 million was available for the wholly owned Nonutility Group and corporate operations at December 31, 2018.

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)	2018	2017	2016	2018	2017	2016
As of Year End						
Balance Outstanding	$166.6	$179.5	$194.4	$ —	$70.0	$ —
Weighted Average Interest Rate	3.00%	1.92%	1.05%	N/A	2.68%	N/A
Annual Average						
Balance Outstanding	$189.2	$172.4	$ 59.8	$ 99.3	$12.2	$ 0.2
Weighted Average Interest Rate	2.30%	1.30%	0.71%	3.17%	2.44%	1.60%
Maximum Month End Balance						
Outstanding	$262.8	$238.7	$194.4	$156.6	$70.0	$ 6.3

11. Common Shareholders' Equity

Authorized, Reserved Common and Preferred Shares

At December 31, 2018 and 2017, 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 4.5 million shares at December 31, 2018 and 4.6 million at December 31, 2017 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, 2018 and 2017, there were 392.5 million 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. With the consummation of the merger, shareholders of all the Company's outstanding stock received $72.00 per share in cash, and all the Company's outstanding common stock was cancelled and delisted from the New York Stock Exchange.

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 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, 2018:

	Year Ended December 31,		
(In millions, except per share data)	2018	2017	2016
Numerator:			
Reported net income (Numerator for Basic and Diluted EPS)	$204.6	$216.0	$211.6
Denominator:			
Weighted-average common shares outstanding (Basic and Diluted EPS)	83.1	83.0	82.8
Basic and diluted earnings per share	**$ 2.46**	**$ 2.60**	**$ 2.55**

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:

	2016			2017		2018	
(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	$ (2.1)	$ (0.1)	$ (2.2)	$ —	$ (2.2)	$ —	$ (2.2)
Deferred income taxes	0.9	—	0.9	—	0.9	—	0.9
Accumulated other comprehensive income (loss)	**$ (1.2)**	**$ (0.1)**	**$ (1.3)**	**$ —**	**$ (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)	2018	2017	2016
Total cost of share-based compensation	$30.7	$40.2	$30.0
Less capitalized cost	7.3	8.6	7.0
Total in other operating expense	23.4	31.6	23.0
Less income tax benefit in earnings	6.0	12.3	9.0
After tax effect of share-based compensation	**$17.4**	**$19.3**	**$14.0**

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 100,000 units as of December 31, 2018, 2017 and 2016.

Most officer, non-officer employee, and non-employee director awards are accounted for as liability awards at their settlement date fair value.

A summary of the status of awards separated between those accounted for as liabilities and equity as of December 31, 2018 and 2017, and changes during the years ended December 31, 2018 and 2017, follow:

	Equity Awards		Liability Awards	
	Units	Wtd. Avg. Grant Date Fair value	Units	Fair value
Awards at January 1, 2017	6,332	$ 33.42	611,580	
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
Granted	243	46.21	272,603	
Vested	(706)	46.21	(289,750)	
Forfeited	—	—	(1,269)	
Awards at December 31, 2018	**—**	**$ —**	**575,124**	**$ 71.98**

As of December 31, 2018, there was $13.9 million of total unrecognized compensation cost associated with outstanding grants. That cost is expected to be recognized over a weighted-average period of 1.6 years. The total fair value of shares vested for liability awards during the years ended December 31, 2018, 2017, and 2016 was $18.2 million, $25.1 million, and $23.7 million, respectively. The total fair value of equity awards vesting during the years ended December 31, 2018, 2017, and 2016 was $0.0 million, $0.5 million, $0.6 million, respectively.

Subsequent to the February 1, 2019 completion of the Merger, and pursuant to the Merger Agreement, all the Company's share- based awards have been settled.

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 $68.8 million and $61.4 million at December 31, 2018 and 2017 respectively. Other than $1.6 million and $1.2 million which is classified in *Accrued liabilities* at December 31, 2018 and 2017, respectively, the liability is included in *Deferred credits & other liabilities*. The impact of these plans on *Other operating* expenses was expense of $3.1 million in 2018, $13.1 million in 2017 and $4.3 million in 2016. The amount recorded in earnings related to the investment activities in Vectren phantom stock associated with these plans during the years ended December 31, 2018, 2017, and 2016, was expense of $2.4 million, expense of $10.1 million, and income of $3.8 million, respectively.

The Company has certain investments held in a rabbi trust 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 $42.6 million and $42.2 million at December 31, 2018 and 2017, respectively. Those investments generated earnings of $0.3 million in 2018, earnings of $5.9 million in 2017, and losses of $3.5 million in 2016. This activity is reflected in *Other operating expenses*.

Pursuant to the Merger Agreement, the Company funded an additional $35.8 million into the rabbi trust designed to pay deferred compensation benefits. A majority of the Company's deferred compensation liabilities will be settled in 2019 and will be funded by a majority of the balance in the rabbi trust.

15. Commitments & Contingencies

Commitments

Future minimum lease payments required under operating leases that have initial or remaining lease terms in excess of one year during the five years following 2018 and thereafter (in millions) are $16.8 in 2019, $10.4 in 2020, $5.7 in 2021, $3.0 in 2022, $2.7 in 2023, and $3.5 thereafter. Total lease expense, for these type of commitments, (in millions) was $19.0 in 2018, $16.5 in 2017, and $13.0 in 2016.

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, 2018, there were 54 open surety bonds supporting future performance. The average face amount of these obligations is $9.3 million, and the largest obligation has a face amount of $41.9 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, 2018, approximately 35 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 to allow those subsidiaries the flexibility to conduct business without posting other forms of collateral. At December 31, 2018, parent level guarantees support a maximum of $444 million of ESG's performance commitments, warranty obligations, project guarantees, and energy savings guarantees.

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.

Given the infrequent occurrence of any performance shortfalls historically on any of these commitments, no reserve for a potential liability has been deemed warranted. 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 issues letters of credit that support consolidated operations. At December 31, 2018, letters of credit outstanding total $22.4 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.

Litigation Related to the Merger

As of November 6, 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," referred to together with the preceding actions, as the "Actions"). 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.

The 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 its 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 its 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 the 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 its 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 the 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 August 10, 2018, the court consolidated the Actions and appointed a group as interim lead plaintiff. On August 22, 2018, the court denied interim lead plaintiffs' preliminary injunction, which sought to halt the Vectren shareholder vote on the Vectren Merger.

Vectren and the Vectren director defendants filed a motion to dismiss on August 15, 2018. On September 4, 2018, the court entered the parties' stipulation that the interim lead plaintiff group is under no obligation to oppose or otherwise respond to the motion to dismiss. Instead, under the stipulation, the lead plaintiff shall file a consolidated amended complaint or designate an operative complaint within thirty (30) days of the entry appointing lead plaintiff and lead counsel, and once the lead plaintiff files a consolidated amended complaint or designates an operative complaint, the case will proceed, as it ordinarily would, under the Federal Rules of Civil Procedure and the Local Rules for the Southern District of Indiana. On September 4, 2018, interim plaintiffs filed a motion for appointment as lead plaintiffs and approval of their selection of counsel as lead counsel. On September 28, 2018, the court granted the interim plaintiffs' motion for appointment and ordered lead plaintiffs to file a consolidated amended complaint or designate an operative complaint within thirty (30) days of the entry in accordance with the court's September 4, 2018 entry of the parties' stipulation.

On October 29, 2018, lead plaintiffs filed an amended consolidated complaint asserting claims under 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 the final proxy statement. Plaintiffs seek compensatory and/or rescissory damages and an award of costs and attorneys' and expert fees. On December 12, 2018, the Court ruled that the amended consolidated complaint rendered the August 15, 2018 motion to dismiss moot.

On December 28, 2018, Plaintiffs Michael Kent and Richard Scarantino filed a notice of voluntary dismissal of their claims against Vectren and Vectren director defendants. On January 9, 2019, the Court entered an order approving the voluntary dismissal and dismissing Kent's and Scarantino's claims without prejudice.

On December 7, 2018, Vectren and the Vectren director defendants filed a motion to dismiss the amended consolidated complaint. Plaintiffs filed their response in opposition to the motion to dismiss on January 11, 2019, and Vectren and the Vectren director defendants filed their reply in support of the motion to dismiss on February 8, 2019.

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

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, except for the rate of return on equity, which remains fixed at the rate determined in the Company's last base 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 not 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 statutes, 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.

Since this August 2014 Order, the Company has received nine semi-annual orders which approved the inclusion in rates of approximately $639 million of approved capital investments through June 30, 2018, and approved updates to the seven-year capital investment plan reflecting capital expenditures of approximately $955 million.

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 has removed the associated projects that were not 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 removed the projects from the plan in accordance with the Opinion when it filed supplemental testimony in its eighth semi-annual TDSIC proceeding on July 25, 2018. The Company does not expect a resulting material impact to results of operations or cash flow from operations.

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 Company received the IURC Order approving the request for recovery and inclusion in the approved seven-year capital investment plan on December 28, 2017. Approximately $15 million of operating expenses and $12 million of capital investments have been included in the plan over a three-year period beginning in 2018. The Company does not have company-owned storage operations in Ohio.

At December 31, 2018 and December 31, 2017, the Company has regulatory assets related to the Plan totaling $99.4 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. 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 pending base rate case, it requested extension to include investments made starting 2018 through completion of the program, currently estimated by 2023. In total, the Company has made capital investments on projects that are now in-service under the DRR totaling $390.9 million as of December 31, 2018, of which $321.1 million has been approved for recovery under the DRR through December 31, 2017. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $38.1 million and $31.2 million at December 31, 2018 and December 31, 2017, respectively.

The PUCO has also issued Orders approving the Company's filings under Ohio House Bill 95. These Orders approve deferral of the Company's Ohio capital expenditure program for items not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. Ohio House Bill 95 Orders also established a prospective bill impact evaluation on the cumulative deferrals, limiting the total deferrals at a level which would equal $1.50 per residential and small general service customer per month. The Company has requested recovery of these deferrals through December 31, 2017 in its rate case, along with a mechanism to recover future Ohio House Bill 95 deferrals. At December 31, 2018 and December 31, 2017, the Company has regulatory assets totaling $97.6 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.

On January 4, 2019, the Company, in conjunction with the PUCO Staff, the City of Dayton, Interstate Gas Supply, and the Retail Energy Supply Association, filed a stipulation and recommendation with the PUCO regarding the requested revenue increase. The non-unanimous Stipulation provides for a nearly $22.7 million increase in the base rates and charges for VEDO's distribution business, based on approximately $622 million of rate base and a rate of return of 7.48%. The Stipulation supports the continuation of the straight-fixed-variable rate design for residential customers and expansion to small commercial customers. In addition, the Stipulation supports the extension of the DRR with targeted completion of the accelerated replacement program by 2023, and the continuation of the deferral authority under Ohio House Bill 95 for VEDO's capital expenditure program with a new mechanism to recover future deferrals over the life of the investments. Finally, the Stipulation supports the continuation of the Company's energy efficiency programs through 2020, with a commitment to file for further extension by the end of 2019. The Company expects an order later in 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 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 Note 16 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 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 Company removed the projects from the plan in accordance with the Opinion when it filed its third semi-annual TDSIC proceeding on August 1, 2018.

On December 5, 2018, the IURC issued an order (December 2018 order) for the third semi-annual filing approving the inclusion in rates of investments made from November 2017 through April 2018. Through the December 2018 order, approximately $59 million of the approved capital investment plan has been incurred and approved for recovery.

As of December 31, 2018 and December 31, 2017, the Company has regulatory assets related to the Electric TDSIC plan totaling $2.2 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.

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 and the remaining investment went into service in 2016. At December 31, 2018 and December 31, 2017, respectively, the Company has regulatory assets totaling $18.6 million and $12.8 million related to depreciation and operating expenses and $6.5 million and $4.7 million 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.

<u>SIGECO Electric Demand Side Management (DSM) Program Filing</u>

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. On February 19, 2019, the Indiana Court of Appeals issued an order upholding the Commission's Order of the 2018-2020 Energy Efficiency Plan in its entirety.

For the twelve months ended December 31, 2018, 2017, and 2016, the Company recognized electric utility revenue of $12.3 million, $11.6 million, and $11.1 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 an order authorizing a 10.32 percent base ROE for the first refund period and prospectively from the date of the order. Pursuant to a US Court of Appeals decision in April 2017 which challenged FERC's prior methodology for calculating ROE, in October 2018, the FERC issued an order which established a modified calculation ROE framework. On November 15, 2018, the FERC issued an order reopening the first complaint case taking the modified ROE framework into consideration. The order proposed a preliminary ROE not materially different from the original order and directed participants to submit briefs regarding the proposed approach. Reply comments in response to the order are due in February 2019.

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. Following the resolution of the first complaint case, a base ROE will be established for this period and prospectively from the date of the order.

Separately, on January 6, 2015, the FERC approved a MISO transmission owner joint request for an adder to the approved ROE. Under FERC regulations, transmission owners that are part of a Regional Transmission Organization (RTO) such as the MISO are authorized to earn an incentive of 50 basis points above the FERC approved ROE. The 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, continues to evaluate the potential impacts of the outstanding cases, and does not expect any impact to be material. As of December 31, 2018, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $130.1 million at December 31, 2018.

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.

On August 10, 2018, most of the intervening parties filed direct testimony opposing the Company's proposed generation investments, and an evidentiary hearing has been completed. The Company continues to support the proposed investments and 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 1, 2019, the Company filed its first request for recovery of these investments using the mechanism allowed under Senate Bill 29, with costs of the completed projects totaling approximately $13 million as of December 31, 2018.

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. On September 5, 2018, the intervening parties filed testimony opposing the investment, and on September 18, 2018 the Company filed its rebuttal testimony in response. On October 10, 2018, a settlement agreement between all but one of the intervening parties and Vectren was filed. The settlement agreement provides for a rate recovery approach whereby the energy produced by the solar farm would be recovered via a fixed rate over the life of the investment. The settlement is now pending before the Commission. An evidentiary hearing was held November 19, 2018. The Company expects an order in the first half of 2019.

Other Generation Developments

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, the President publicly called for immediate action by the DOE. To date, the DOE has not publicly acted, 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.

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 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 2017 corporate sustainability report.

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

The Company is subject to extensive environmental regulation pursuant to a variety of federal, state, and municipal laws and regulations. These environmental regulations impose, among other things, restrictions, liabilities, and obligations in connection with the storage, transportation, treatment, and disposal of hazardous substances and limit airborne emissions from electric generating facilities including particulate matter, sulfur dioxide (SO_2), nitrogen oxide (NO_x), and mercury, among others. Environmental legislation and regulation also requires that facilities, sites, and other properties associated with the Company's operations be operated, maintained, abandoned, and reclaimed to the satisfaction of applicable regulatory authorities.

The Company's current costs to comply with these laws and regulations are significant to its results of operations and financial condition. Similar to the costs associated with federal mandates in the Pipeline Safety Law, Senate Bill 251 is also applicable to federal environmental mandates impacting SIGECO's electric operations.

Coal Ash Waste Disposal, Ash Ponds and Water

Coal Combustion Residuals Rule

In April 2015, the EPA finalized its Coal Combustion Residuals (CCR) rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The final rule allows beneficial reuse of ash and the majority of the ash generated by the Company's generating plants will continue to be reused. 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. On August 21, 2018, the U.S. Court of Appeals for the D.C. Circuit issued an opinion in the underlying judicial review litigation, agreeing largely with the environmental challengers by vacating and remanding provisions of the 2015 rule that allowed unlined ash ponds to receive coal ash until a leak is detected and exempted inactive "legacy" impoundments. This decision effectively undercuts further attempts by EPA to make the rule less stringent on reconsideration.

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. The CCR rule requires that companies complete location restriction determinations by October 18, 2018. The Company has completed its evaluation under the rule and determined that one F.B. Culley pond and one A.B. Brown pond fail the aquifer placement location restriction requiring that ash cannot be disposed within five feet of the uppermost groundwater aquifer. The Company will be required to cease disposal and commence closure of the ponds by October 31, 2020. The Company plans to seek the extensions available under the CCR rule that would allow the Company to continue to use the ponds through completion of the generation transition plans by December 31, 2023.

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 December 31, 2018, the Company has recorded an approximate $40 million asset retirement obligation (ARO). The recorded AROreflects 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.

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. In the case of Vectren's water discharge permits, in 2017 the Indiana Department of Environmental Management (IDEM) issued final renewals for Company's F.B. Culley and A.B. Brown power plants. IDEM agreed that units identified for retirement by December 2023 would not be required to install new treatment technology to meet ELG, and approved a 2020 compliance date for dry bottom ash and a 2023 compliance date for flue gas desulfurization wastewater treatment standards for the remaining coal-fired unit at F.B. Culley.

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. 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>

MATS Reconsideration

On December 27, 2018, US EPA proposed to revise the Supplemental Cost Finding for the Mercury and Air Toxics Standards (MATS) rule, as well as the hazardous air pollutants risk and technology review (RTR) required under the CAA. Specifically, the agency proposes to determine that it is not "appropriate and necessary" to regulate hazardous air pollutant emission from power plants under Section 112 of the CAA. Under the proposal, the emission standards and other requirements of the MATS rule, first promulgated in 2012, would remain in place, since EPA is not proposing to remove coal-fired power plants from the list of sources that are regulated under Section 112 of the Act. The Company is in full compliance with MATS and does not anticipate significant impacts or operational changes under this proposal.

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

Clean Power Plan and ACE Rule

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.

On August 31, 2018, EPA published its proposed CPP replacement rule, the Affordable Clean Energy (ACE) rule, which if finalized, would require that each state set unit by unit heat rate performance standards, considering such factors as remaining useful life. Under the ACE rule, a state would have three years to finalize its program and the EPA would have 18 months to approve, making compliance likely in 2023-2024. Comments to the ACE proposal were due October 31, 2018. Vectren filed comments which largely support EPA's ACE proposal.

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 $44.7 million ($23.9 million at Indiana Gas and $20.8 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 substantially all 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, 2018 and December 31, 2017, approximately $2.6 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.

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,			
	2018		2017	
(In millions)	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	$2,214.1	$2,277.3	$1,838.7	$1,981.2
Short-term borrowings & notes payable	166.6	166.6	249.5	249.5
Cash & cash equivalents	29.6	29.6	16.6	16.6
Natural gas purchase instrument assets (1)	—	—	0.5	0.5
Natural gas purchase instrument liabilities (2)	12.1	12.1	4.5	4.5
Interest rate swap liabilities (3)	0.1	0.1	1.4	1.4

(1) Presented in "Other utility & corporate investments" on the Consolidated Balance Sheets.
(2) Presented in "Accrued liabilities" and "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.

As described in Note 10, the Company, through SIGECO, executed forward starting interest rate swaps during 2017 providing that on January 1, 2020, the Company will begin hedging variability in interest rates. 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.

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, 2018 and 2017, the fair value for these financial instruments was not estimated. The carrying value of these investments at December 31, 2018 and 2017 were approximately $9.6 million.

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.

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 $140.8 million in 2018, $157.1 million in 2017, and $117.8 million in 2016.

Corporate and Other includes unallocated corporate expenses such as Merger-related costs, 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.

(In millions)	Year Ended December 31, 2018	2017	2016
Revenues			
Utility Group			
Gas Utility Services	$ 857.8	$ 812.7	$ 771.7
Electric Utility Services	582.5	569.6	605.8
Other Operations	47.1	45.6	42.2
Eliminations	(46.8)	(45.3)	(41.9)
Total Utility Group	**1,440.6**	**1,382.6**	**1,377.8**
Nonutility Group			
Infrastructure Services	965.7	996.1	813.3
Energy Services	291.3	281.8	260.0
Total Nonutility Group	**1,257.0**	**1,277.9**	**1,073.3**
Eliminations, net of Corporate & Other Revenues	(4.3)	(3.2)	(2.8)
Consolidated Revenues	**$2,693.3**	**$2,657.3**	**$2,448.3**
Profitability Measures - Net Income			
Utility Group Net Income			
Gas Utility Services	$ 99.3	$ 115.5	$ 76.1
Electric Utility Services	76.2	75.2	84.7
Other Operations	15.0	(14.9)	12.8
Total Utility Group Net Income	**190.5**	**175.8**	**173.6**
Nonutility Group Net Income (Loss)			
Infrastructure Services	37.7	32.3	25.0
Energy Services	15.6	10.7	12.5
Other Businesses	(14.2)	(1.9)	(0.6)
Total Nonutility Group Net Income	**39.1**	**41.1**	**36.9**
Corporate & Other Net Income	(25.0)	(0.9)	1.1
Consolidated Net Income	**$ 204.6**	**$ 216.0**	**$ 211.6**

(In millions)	Year Ended December 31, 2018	2017	2016
Amounts Included in Profitability Measures			
Depreciation & Amortization			
Utility Group			
Gas Utility Services	$130.1	$118.9	$108.1
Electric Utility Services	91.8	89.5	87.1
Other Operations	28.2	26.1	23.9
Total Utility Group	**250.1**	**234.5**	**219.1**
Nonutility Group			
Infrastructure Services	40.0	39.7	38.2
Energy Services	1.9	1.9	2.5
Other Businesses	0.2	0.1	0.2
Total Nonutility Group	**42.1**	**41.7**	**40.9**
Consolidated Depreciation & Amortization	**$292.2**	**$276.2**	**$260.0**
Interest Expense			
Utility Group			
Gas Utility Services	$ 49.3	$ 43.0	$ 40.1
Electric Utility Services	26.7	25.8	27.0
Other Operations	5.4	3.8	2.6
Total Utility Group	**81.4**	**72.6**	**69.7**
Nonutility Group			
Infrastructure Services	14.0	13.8	12.8
Energy Services	0.7	0.6	1.9
Other Businesses	1.2	1.0	0.9
Total Nonutility Group	**15.9**	**15.4**	**15.6**
Corporate & Other	0.1	(0.3)	0.2
Consolidated Interest Expense	**$ 97.4**	**$ 87.7**	**$ 85.5**
Income Taxes			
Utility Group			
Gas Utility Services	$ 13.6	$ 25.4	$ 47.1
Electric Utility Services	21.7	41.4	50.1
Other Operations	(2.6)	(6.1)	2.3
Total Utility Group	**32.7**	**60.7**	**99.5**
Nonutility Group			
Infrastructure Services	13.5	(12.9)	17.9
Energy Services	(4.4)	(1.5)	(3.5)
Other Businesses	(4.8)	0.9	0.3
Total Nonutility Group	**4.3**	**(13.5)**	**14.7**
Corporate & Other	(8.3)	(0.8)	(1.3)
Consolidated Income Taxes	**$ 28.7**	**$ 46.4**	**$112.9**

(In millions)	Year Ended December 31, 2018	2017	2016
Capital Expenditures			
Utility Group			
Gas Utility Services	$ 377.2	$ 391.4	$ 358.5
Electric Utility Services	163.6	105.3	106.4
Other Operations	44.4	57.9	39.0
Non-cash costs & changes in accruals	(12.4)	(3.7)	(7.1)
Total Utility Group	**572.8**	**550.9**	**496.8**
Nonutility Group			
Infrastructure Services	50.2	48.4	43.2
Energy Services	1.6	3.2	1.8
Other Businesses, net of eliminations	—	0.1	0.2
Total Nonutility Group	**51.8**	**51.7**	**45.2**
Consolidated Capital Expenditures	**$ 624.6**	**$ 602.6**	**$ 542.0**

(In millions)	At December 31, 2018	2017	2016
Assets			
Utility Group			
Gas Utility Services	$3,794.2	$3,457.8	$3,091.0
Electric Utility Services	1,950.0	1,820.3	1,788.4
Other Operations, net of eliminations	131.9	220.1	161.5
Total Utility Group	**5,876.1**	**5,498.2**	**5,040.9**
Nonutility Group			
Infrastructure Services	571.2	552.6	513.9
Energy Services	156.1	155.8	182.7
Other Businesses, net of eliminations and reclassifications	56.0	59.1	53.3
Total Nonutility Group	**783.3**	**767.5**	**749.9**
Corporate & Other	619.5	449.1	628.4
Eliminations	(683.5)	(475.5)	(618.5)
Consolidated Assets	**$6,595.4**	**$6,239.3**	**$5,800.7**

21. Additional Balance Sheet & Operational Information

Inventories consist of the following:

(In millions)	At December 31, 2018	2017
Gas in storage – at LIFO cost	$ 36.0	$ 36.0
Coal & oil for electric generation - at average cost	16.6	43.1
Materials & supplies	52.8	46.2
Other	1.4	1.3
Total inventories	**$ 106.8**	**$126.6**

Based on the average cost of gas purchased during December 2018, the cost of replacing inventories carried at LIFO cost was greater than carrying value at December 31, 2018 by $2.0 million. Based on the average cost of gas purchased during December 2017, the cost of replacing inventories carried at LIFO cost was less than the carrying value at December 31, 2017 by $2.0 million.

Prepayments & other current assets consist of the following:

(In millions)	At December 31, 2018	2017
Prepaid gas delivery service	$23.2	$ 26.6
Prepaid taxes	9.9	3.8
Other prepayments & current assets	21.0	16.6
Total prepayments & other current assets	**$54.1**	**$ 47.0**

Investments in unconsolidated affiliates consist of the following:

(In millions)	At December 31, 2018	2017
ProLiance Holdings, LLC	$0.6	$18.9
Other nonutility partnerships & corporations	0.6	0.6
Other utility investments	0.2	0.2
Total investments in unconsolidated affiliates	**$1.4**	**$19.7**

Other utility & corporate investments consist of the following:

(In millions)	At December 31, 2018	2017
Cash surrender value of life insurance policies	$42.6	$42.2
Other	1.0	1.5
Total other utility & corporate investments	**$43.6**	**$43.7**

Goodwill by operating segment follows:

(In millions)	At December 31, 2018	2017
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, 2018	2017
Refunds to customers & customer deposits	$ 83.9	$ 51.4
Accrued taxes	46.3	55.7
Accrued interest	17.5	19.6
Deferred compensation & post retirement benefits	6.9	6.4
Accrued salaries & other	99.1	89.2
Total accrued liabilities	**$253.7**	**$222.3**

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

(In millions)	2018	2017
Asset retirement obligation, January 1	$107.0	$106.7
Accretion	4.5	4.3
Changes in estimates, net of cash payments	4.4	(4.0)
Asset retirement obligation, December 31	**115.9**	**107.0**

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

	Year Ended December 31,		
(In millions)	2018	2017	2016
ProLiance Holdings, LLC	$(18.2)	$(0.3)	$(0.5)
Other	(0.1)	(0.8)	0.3
Total equity in earnings (losses) of unconsolidated affiliates	**$(18.3)**	**$(1.1)**	**$(0.2)**

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

	Year Ended December 31,		
(In millions)	2018	2017	2016
AFUDC – borrowed funds	$29.8	$24.8	$20.3
AFUDC – equity funds	3.4	2.6	2.2
Nonutility plant capitalized interest	1.2	1.2	1.0
Interest income, net	0.7	1.0	1.3
All other income	1.0	2.1	5.0
Total other income – net	**$36.1**	**$31.7**	**$29.8**

Supplemental Cash Flow Information:

	Year Ended December 31,		
(In millions)	2018	2017	2016
Cash paid (received) for:			
Interest	$99.5	$86.4	$86.6
Income taxes	38.2	9.6	(3.6)

As of December 31, 2018 and 2017, the Company has accruals related to utility and nonutility plant purchases totaling approximately $36.1 million and $28.6 million, respectively.

22. Impact of Recently Issued Accounting Guidance

Leases

In February 2016, the FASB issued new accounting guidance, ASU 2016-02, 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. The Company has adopted the guidance effective January 1, 2019.

ASU 2016-02 includes multiple practical expedients that may be elected but must be elected as a package. These practical expedients allow lessees and lessors to: 1) not reassess expired or existing contracts to determine whether they are subject to lease accounting guidance, (2) not reconsider lease classification at transition, and (3) not evaluate previously capitalized initial direct costs under the revised requirements. The Company has elected to utilize this package of three expedients.

The Company has adopted an accounting policy that exempts leases with terms of less than one year from the recognition requirements of the standard. The ASU also provides lessees the option of electing an accounting policy, by class of underlying asset, in which the lessee may choose not to separate nonlease components from lease components. The Company has adopted this practical expedient for certain classes of leases.

In January 2018, the FASB issued 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 has applied the election under 2018-01 to its existing or expired land easements as part of its transition.

In July 2018, the FASB issued ASU 2018-11, providing entities an optional transitional relief method to apply ASU 2016-02 at the adoption date and to recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. The Company has applied the election under 2018-11 to its 2016-02 adoption.

As of December 31, 2018, the Company has reviewed substantially all its leases and related contracts and has completed its preliminary evaluation of the guidance. The population primarily consists of leases of equipment for our infrastructure services business and office facility leases. While the Company is continuing to evaluate the full impact of the standard on the consolidated financial statements and related disclosures, upon adoption, the Company will recognize right-of-use assets and lease liabilities for leases currently classified as operating leases. No material impact to net income is expected.

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 2018 and 2017 follows:

(In millions, except per share amounts)	Q1	Q2	Q3	Q4
2018				
Operating revenues	$658.4	$644.3	$665.0	$725.4
Operating income	84.3	55.5	76.3	96.7
Net income	63.5	22.2	50.4	68.5
Earnings per share:				
Basic and Diluted	$ 0.76	$ 0.27	$ 0.61	$ 0.82
2017				
Operating revenues	$624.5	$630.7	$691.2	$711.0
Operating income	101.4	74.0	107.3	36.9
Net income	55.4	37.6	61.9	61.2
Earnings per share:				
Basic and Diluted	$ 0.67	$ 0.45	$ 0.75	$ 0.74

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 for the year ended December 31, 2018, included in CenterPoint Energy's Annual Report on Form 10-K for the fiscal year ended December 31, 2018, filed with the Securities and Exchange Commission (SEC) on February 28, 2019;
- the unaudited consolidated financial statements of CenterPoint Energy for the six months ended June 30, 2019, included in CenterPoint Energy's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2019 (Q2 2019 Form 10-Q), filed with the SEC on August 7, 2019; and
- the consolidated financial statements of Vectren for the year ended December 31, 2018, filed as Exhibit 99.1 to this Current Report on Form 8-K.

Vectren Merger

On February 1, 2019 (Closing Date), the merger (Vectren Merger) contemplated by the Agreement and Plan of Merger dated as of April 21, 2018 (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), was completed. Pursuant to the Merger Agreement, on and subject to the terms and conditions set forth therein, Merger Sub merged with and into Vectren, with Vectren continuing as the surviving corporation in the Vectren Merger and becoming a wholly-owned subsidiary of CenterPoint Energy. Under the Merger Agreement, CenterPoint Energy paid cash consideration of approximately $6.0 billion, 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 close of the Vectren Merger. These amounts did not include a stub period cash dividend of $0.41145 per share, which was declared, with CenterPoint Energy's consent, by Vectren's board of directors on January 16, 2019, paid to Vectren stockholders as of the record date of February 1, 2019.

Financing

In anticipation of the Vectren Merger, in August and October 2018, CenterPoint Energy completed registered public offerings of its Common Stock, Series A Preferred Stock, Series B Preferred Stock and Senior Notes (in each case defined below and collectively, Merger Financings). These offerings provided total net proceeds of approximately $5.0 billion for the partial funding of the Merger Consideration. CenterPoint Energy funded the remaining balance of the Merger Consideration after completion of the Merger Financings by issuances of commercial paper.

The pro forma financial statements give effect to the following, including the net proceeds of the Merger Financings, as well as the issuance of commercial paper, that were completed prior to the Closing Date (see Note 2 for further details):

- $790 million from the issuance of CenterPoint Energy's Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Stock (Series A Preferred Stock) completed on August 22, 2018;
- $950 million from the issuance of CenterPoint Energy's 7.00% Series B Mandatory Convertible Preferred Stock (Series B Preferred Stock) completed on October 1, 2018;

- $1.8 billion from the issuance of CenterPoint Energy common stock, par value $0.01 per share (Common Stock), completed on October 1, 2018;
- $1.5 billion from the issuance of CenterPoint Energy senior notes (Senior Notes) completed on October 5, 2018; and
- approximately $1.0 billion of commercial paper issued beginning in January 2019.

The Unaudited Pro Forma Condensed Combined Statements of Income (pro forma statements of income) for the six months ended June 30, 2019 and the year ended December 31, 2018, give effect to the Vectren Merger as if it were completed on January 1, 2018. A pro forma condensed combined balance sheet as of June 30, 2019 has not been included as the Vectren Merger is reflected in the historical condensed consolidated balance sheet as of June 30, 2019 disclosed in CenterPoint Energy's Q2 2019 Form 10-Q.

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) expected to have a continuing impact on the consolidated results following the Vectren Merger.

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 based on preliminary estimates, the total amounts recorded 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 allocation of the Vectren Merger as disclosed in CenterPoint Energy's Q2 2019 Form 10-Q.

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

CENTERPOINT ENERGY, INC.
UNAUDITED PRO FORMA CONDENSED COMBINED STATEMENTS OF INCOME
For the Six Months Ended June 30, 2019

	CenterPoint Energy Historical	Vectren Historical January 2019 Only	Pro Forma Adjustments (Note 3)	CenterPoint Energy Pro Forma
	(In Millions, Except Per Common Share Amounts)			
Revenues:				
Utility revenues	$ 3,716	$ 181	$ —	$ 3,897
Non-utility revenues	2,613	68	—	2,681
Total	6,329	249	—	6,578
Expenses:				
Utility natural gas, fuel and purchased power	999	75	—	1,074
Non-utility cost of revenues, including natural gas	2,161	20	—	2,181
Operation and maintenance	1,745	133	(37) (e)	1,804
			(37) (h)	
Depreciation and amortization	653	25	(11) (b)	667
Taxes other than income taxes	239	8	—	247
Total	5,797	261	(85)	5,973
Operating Income	532	(12)	85	605
Other Income (Expense):				
Gain on marketable securities	147	—	—	147
Loss on indexed debt securities	(154)	—	—	(154)
Interest and other finance charges	(255)	(5)	—	(260)
Interest on Securitization Bonds	(22)	—	—	(22)
Equity in earnings of unconsolidated affiliates, net	136	—	—	136
Other, net	31	—	—	31
Total	(117)	(5)	—	(122)
Income (Loss) Before Income Taxes	415	(17)	85	483
Income tax expense	51	3	22 (f)	76
Net Income (Loss)	364	(20)	63	407
Preferred stock dividend requirement	59	—	—	59
Income available to common shareholders	$ 305	$ (20)	$ 63	$ 348
Basic Earnings Per Common Share	$ 0.61			$ 0.69
Diluted Earnings Per Common Share	$ 0.61			$ 0.69
Weighted Average Common Shares Outstanding, Basic	502			502
Weighted Average Common Shares Outstanding, Diluted	504			504

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, 2018

	CenterPoint Energy Historical	Vectren Historical	Pro Forma Adjustments (Note 3)	CenterPoint Energy Pro Forma
	(In Millions, Except Per Common Share Amounts)			
Revenues:				
Utility revenues	$ 6,163	$ 1,440	$ —	$ 7,603
Non-utility revenues	4,426	1,253	(3) (g)	5,676
Total	10,589	2,693	(3)	13,279
Expenses:				
Utility natural gas, fuel and purchased power	1,410	503	—	1,913
Non-utility cost of revenues, including natural gas	4,364	405	(2) (g)	4,767
Operation and maintenance	2,335	1,114	(47) (e)	3,401
			(1) (g)	
Depreciation and amortization	1,243	292	20 (b)	1,555
Taxes other than income taxes	406	66	—	472
Total	9,758	2,380	(30)	12,108
Operating Income	831	313	27	1,171
Other Income (Expense):				
Loss on marketable securities	(22)	—	—	(22)
Loss on indexed debt securities	(232)	—	—	(232)
Interest and other finance charges	(361)	(66)	(45) (a)	(472)
Interest on Securitization Bonds	(59)	—	—	(59)
Equity in earnings (losses) of unconsolidated affiliates, net	307	(18)	—	289
Other, net	50	5	—	55
Total	(317)	(79)	(45)	(441)
Income Before Income Taxes	514	234	(18)	730
Income tax expense (benefit)	146	29	(4) (f)	171
Net Income	368	205	(14)	559
Preferred stock dividend requirement	35	—	31 (c)	117
			51 (d)	
Income available to common shareholders	$ 333	$ 205	$ (96)	$ 442
Basic Earnings Per Common Share	$ 0.74			$ 0.88
Diluted Earnings Per Common Share	$ 0.74			$ 0.88
Weighted Average Common Shares Outstanding, Basic	449		52 (i)	501
Weighted Average Common Shares Outstanding, Diluted	452		52 (i)	504

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, 2019, and the year ended December 31, 2018, give effect to the Vectren Merger as if it were completed on January 1, 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. These reclassifications have no material impact on the historical operating income or net income 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 (i) directly attributable to the Vectren Merger, (ii) factually supportable and (iii) expected to have a continuing impact on the consolidated 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 as a result of the Vectren Merger at the conclusion of the measurement period may differ materially from the information presented. These estimates are subject to change pending further analysis during the measurement period of acquisition accounting.

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. See CenterPoint Energy's Q2 2019 Form 10-Q for further discussion.

The accounting policies used in the preparation of the pro forma financial statements are those described in CenterPoint Energy's audited consolidated financial statements for the year ended December 31, 2018 and updated in CenterPoint Energy's Q2 2019 Form 10-Q. The historical income statements for the six months ended June 30, 2019 for CenterPoint Energy and for the month ended January 31, 2019 for Vectren reflect all normal recurring adjustments that are, in the opinion of management, necessary to present fairly the results of operations for the respective periods.

Transaction costs recorded in the historical statements of income have been excluded from the pro forma statements of income as they reflect nonrecurring charges directly related to the Vectren Merger.

The pro forma financial statements do not reflect any pro forma adjustments to the historical results for the realization of any expected cost savings or other synergies nor the costs to achieve synergies from the Vectren Merger as a result of restructuring activities following the completion of the Vectren Merger. Severance costs totaling $61 million incurred during 2019 are reflected in the historical statement of income for the six months ended June 30, 2019. No pro forma adjustment was made to eliminate these costs as they were not directly attributable to the Vectren Merger.

(2) Financing Transactions

The pro forma financial statements give effect to the following financing transactions discussed below that were completed prior to the Closing Date.

CenterPoint Energy obtained commitments by lenders for a $5.0 billion, 364-day senior unsecured bridge term loan facility (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. Upon execution of the Bridge Facility, CenterPoint Energy deferred debt issuance costs of $25 million in other assets, of which $25 million was amortized as debt issuance expense in the historical statements of income for the year ended December 31, 2018. CenterPoint Energy terminated all remaining commitments under the Bridge Facility promptly following the issuance of the Senior Notes, and these pro forma financial statements do not reflect any borrowings under the Bridge Facility.

On August 22, 2018, CenterPoint Energy completed the issuance of 800,000 shares of its Series A Preferred Stock for net proceeds of $790 million (net of $10 million of issuance costs) with an aggregate liquidation value of $800 million. The Series A Preferred Stock accrue dividends in cash, calculated as a percentage of the aggregate liquidation value, at a fixed annual rate of 6.125% per annum to, but excluding, September 1, 2023, and at an annual rate of 3-month LIBOR plus a spread of 3.270% thereafter. During 2018, CenterPoint Energy utilized the net proceeds of $790 million to temporarily pay down outstanding commercial paper to reduce holding costs.

On October 1, 2018, CenterPoint Energy completed the issuance of 977,500 shares of its Series B Preferred Stock for net proceeds of $950 million (net of $28 million of issuance costs) with an aggregate liquidation value of $978 million. Once declared by the CenterPoint Energy Board of Directors, CenterPoint Energy will pay dividends in cash or shares of Common Stock, calculated as a percentage of the aggregate liquidation value, at a rate of 7% per annum.

On October 1, 2018, CenterPoint Energy completed the issuance of 69,633,027 shares of its Common Stock at a public offering price of $27.25 per share for net proceeds of $1,844 million (net of $54 million of issuance costs).

On October 5, 2018, CenterPoint Energy completed the issuance of $1.5 billion aggregate principal amount of Senior Notes, for net proceeds of $1.49 billion (net of issuance costs of $12 million). The Senior Notes bear interest between 3.60% and 4.25%, with a weighted average interest rate of 3.90%, maturing between 2021 and 2028.

In May 2018, CenterPoint Energy entered into an amendment to its Revolving Credit Facility that increased 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. The increase in aggregate commitments became effective on October 5, 2018.

For purposes of the pro forma financial statements, CenterPoint Energy has presented the funding of the remaining balance of the Merger Consideration through the issuance of commercial paper of approximately $1 billion beginning on January 7, 2019 with a weighted average interest rate of 2.47% per annum as of August 7, 2019.

(3) Adjustments to Pro Forma Statements of Income and Earnings Per Share

(a) *Interest and other finance charges.* Reflects additional interest expense and amortization of debt issuance costs related to the financing transactions described in Note 2 above. No pro forma adjustments were recorded for the six months ended June 30, 2019 as the financing transactions were substantially completed during 2018, and interest expense on commercial paper borrowings beginning in January 2019 is reflected in the historical statement of income for the six months ended June 30, 2019.

	Year Ended December 31, 2018
	(in millions)
Annual interest expense related to the issuance of the Senior Notes	$ 58
Annual amortization of the Senior Notes debt issuance costs (1)	2
Elimination of CenterPoint Energy's historical interest expense related to the Senior Notes	(15)
Elimination of CenterPoint Energy's historical amortization of Bridge Facility fees (2)	(25)
Estimated interest expense related to commercial paper (3) (4)	25
Net adjustments to interest and other finance charges	$ 45

(1) Reflects total debt issuance costs of $12 million amortized over the weighted-average term of the Senior Notes of 6 years.
(2) Bridge Facility fees were incurred and fully amortized by CenterPoint Energy during the year ended December 31, 2018.
(3) An increase or decrease of one-eighth percent to the assumed interest rate would increase or decrease interest expense for the commercial paper by approximately $1 million for the year ended December 31, 2018.
(4) Reflects interest expense on approximately $1 billion of commercial paper, the amount of commercial paper used to fund the remaining portion of the cash consideration after the application of funds from the Merger Financings at a weighted average interest rate of 2.47% as of August 7, 2019.

(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, 2019	Year Ended December 31, 2018
	(in years)	(in millions)	
Eliminate historical amortization of intangible assets (1)		$ (20)	$ (4)
Operation and maintenance agreements	24	—	1
Backlog (2)	1	—	—
Customer relationships	18	6	12
Trade Names	10	3	6
Regulatory assets not earning a return (3)	10	—	5
Net adjustment to depreciation and amortization		$ (11)	$ 20

(1) Amounts reflected in the historical statements of income of Vectren prior to the Closing Date and in CenterPoint Energy's historical statements of income directly attributable to the Vectren Merger subsequent to the Closing Date.

(2) 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 consolidated results following the Vectren Merger.

(3) No pro forma adjustment was necessary for the six months ended June 30, 2019 as the amortization related to regulatory assets not earning a return is reflected in the historical statements of income.

(c) *Series A Preferred Stock dividends.* Reflects the incremental accumulated dividends from the issuance of the Series A Preferred Stock of $31 million for the year ended December 31, 2018. Accumulated dividends of $25 million related to Series A Preferred Stock are reflected on the historical statement of income for the six months ended June 30, 2019.

(d) *Series B Preferred Stock dividends.* Reflects the incremental accumulated dividends from the issuance of the Series B Preferred Stock of $51 million for the year ended December 31, 2018. Accumulated dividends of $34 million related to Series B Preferred Stock are reflected on the historical statement of income for the six months ended June 30, 2019.

(e) *Transaction costs.* Reflects the elimination of non-recurring transaction costs of $37 million for the six months ended June 30, 2019, related to the Vectren Merger incurred by Vectren and $28 million and $19 million for the year ended December 31, 2018, related to the Vectren Merger incurred by CenterPoint Energy and Vectren, respectively, and included in the historical statement of income.

(f) *Income tax expense.* Reflects the income tax effects of the pro forma adjustments calculated using an estimated combined company statutory income tax rate of 26% and 24% for the six months ended June 30, 2019 and for the year ended December 31, 2018, respectively. The assumed statutory tax rates do not take into account any possible future tax events that may impact the consolidated company.

(g) *Intercompany transactions.* Reflects the elimination of $3 million of non-utility revenues, $2 million of non-utility cost of revenues and $1 million of operation and maintenance expenses for the year ended December 31, 2018 related to transactions between CenterPoint Energy and Vectren. Elimination of transactions between CenterPoint Energy and Vectren for the six months months ended June 30, 2019 are reflected in the historical statement of income.

(h) *Stock-based Compensation.* Reflects the elimination of $37 million of non-recurring accelerated stock-based compensation expense recorded in the historical statement of income for the six months ended June 30, 2019. Pursuant to the Merger Agreement, the unvested stock units and performance units of Vectren held by Vectren's employees and non-employee directors immediately vested and were cashed out immediately following the Vectren Merger.

(i) *Earnings per common share.* Reflects the issuance of 69,633,027 shares of Common Stock on October 1, 2018 as if the issuance had occurred on January 1, 2018, resulting in an incremental increase of 52,272,464 weighted average shares of Common Stock utilized in the computation of earnings per common share. Diluted shares outstanding include potential dilution of common stock equivalent shares that may occur if securities to issue common stock were exercised or converted into Common Stock at the maximum conversion rate. Diluted earnings per common share applies the if-converted method by adjusting for the more dilutive effect of the Series B Preferred Stock as a result of either its accumulated dividend for the period in the numerator or the assumed-converted common share equivalent in the denominator. No adjustment for the shares issuable on conversion is reflected in the computation of the pro forma diluted earnings per common share for the six months ended June 30, 2019 or the year ended December 31, 2018 because the assumed conversion of those shares would be anti-dilutive.