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): **March 26, 2021**

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	The 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	The 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. o

Item 7.01. Regulation FD Disclosure.

Included herein is financial information related to Vectren Utility Holdings, Inc. ("VUHI") and Southern Indiana Gas & Electric Company ("SIGECO"). SIGECO is a wholly-owned subsidiary of VUHI. VUHI is a wholly-owned subsidiary of Vectren Corporation ("Vectren"), which in turn, is a wholly-owned subsidiary of CenterPoint Energy, Inc. ("CenterPoint Energy").

Exhibits 99.1 and 99.2 to this Current Report on Form 8-K include audited financial statements for the years ended December 31, 2020 and 2019, for VUHI and SIGECO, respectively. These financial statements are not intended to comply with Regulation S-X or Regulation S-K. Exhibit 99.3 includes certain supplementary financial and operational data of SIGECO for the years ended December 31, 2020 and 2019.

Each of Exhibits 99.1, 99.2 and 99.3 is furnished, not filed, pursuant to Item 7.01. Accordingly, none of the information will be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), or otherwise subject to the liability of that section, as amended, and the information in Exhibits 99.1, 99.2 and 99.3 will not be incorporated by reference into any registration statement filed by CenterPoint Energy under the Securities Act of 1933, as amended, unless specifically identified as being incorporated by reference.

Item 9.01. Financial Statements and Exhibits.

Each of Exhibits 99.1, 99.2 and 99.3 is furnished, not filed, pursuant to Item 7.01. Accordingly, none of the information will be deemed "filed" for purposes of Section 18 of the Exchange Act, or otherwise subject to the liability of that section, as amended, and the information in Exhibits 99.1, 99.2 and 99.3 will not be incorporated by reference into any registration statement filed by CenterPoint Energy under the Securities Act of 1933, as amended, unless specifically identified as being incorporated by reference.

(d) Exhibits.

EXHIBIT NUMBER	EXHIBIT DESCRIPTION
99.1	Reporting Package of Vectren Utility Holdings, Inc.
99.2	Reporting Package of Southern Indiana Gas & Electric Company
99.3	Financial and Operational Data of Southern Indiana Gas & Electric Company
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: March 26, 2021

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

VECTREN UTILITY HOLDINGS INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED FINANCIAL STATEMENTS

For the year ended December 31, 2020

Contents

DEFINITIONS

AFUDC	Allowance for funds used during construction
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
ASU	Accounting Standard Update
CECA	Clean Energy Cost Adjustment
COVID-19	Novel coronavirus disease 2019, and any mutations or variants thereof, and related global outbreak that was subsequently declared a pandemic by the World Health Organization
CODM	Chief Operating Decision Maker who is the Company's Chief Executive Officer
CSIA	Compliance and System Improvement Adjustment
DRR	Distribution Replacement Rider
DSMA	Demand Side Management Adjustment
ECA	Environmental Cost Adjustment
EEFC	Energy Efficiency Funding Component
EEFR	Energy Efficiency Funding Rider
EPA	Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulation Commission
IDEM	Indiana Department of Environmental Management
IURC	Indiana Utility Regulatory Commission
MISO	Midcontinent Independent System Operator
MW	megawatts
PUCO	Public Utilities Commission of Ohio
SERP	Supplemental Executive Retirement Plan
SRC	Sales Reconciliation Component
TCJA	Tax Cuts and Jobs Acts
TDSIC	Transmission, Distribution and Storage System Improvement Charge
TSCR	Tax Savings Credit Rider
VISCO	Vectren Infrastructure Services Corporation, a wholly -owned subsidiary of Vectren

INDEPENDENT AUDITORS' REPORT

To the Director of Vectren Utility Holdings, Inc.

We have audited the accompanying consolidated financial statements of Vectren Utility Holdings, Inc. and its subsidiaries (the "Company")(a wholly owned subsidiary of Vectren Corporation), which comprise the consolidated balance sheets as of December 31, 2020 and 2019, and the related consolidated statements of income, cash flows and common shareholder's equity for each of the three years in the period ended December 31, 2020, 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 Utility Holdings, Inc. and its subsidiaries as of December 31, 2020 and 2019, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2020, in accordance with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP
Indianapolis, Indiana
March 8, 2021

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

	At December 31, 2020		At December 31, 2019	
ASSETS				
Current Assets				
Cash & cash equivalents	$	8.2	$	10.9
Accounts receivable - less reserves of $6.4 & $4.8, respectively		126.4		103.4
Accrued unbilled revenues - less reserves of $1.1 and $-0-, respectively		97.4		87.2
Inventories		120.7		112.2
Recoverable fuel & natural gas costs		2.5		2.4
Prepayments & other current assets		41.4		26.9
Total current assets		**396.6**		**343.0**
Utility Plant				
Original cost		8,640.2		8,065.7
Less: accumulated depreciation & amortization		3,230.5		3,052.4
Net utility plant		**5,409.7**		**5,013.3**
Other investments		17.0		15.8
Nonutility plant - net		203.5		181.7
Goodwill		205.0		205.0
Regulatory assets		518.1		466.7
Other assets		72.1		77.5
TOTAL ASSETS	**$**	**6,822.0**	**$**	**6,303.0**

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

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

	At December 31, 2020	At December 31, 2019
LIABILITIES & SHAREHOLDER'S EQUITY		
Current Liabilities		
Accounts payable	$ 188.2	$ 154.6
Affiliated payables to CenterPoint Energy	7.3	4.0
Payables to other Vectren companies	80.9	33.0
Accrued liabilities	128.6	142.1
Current maturities of long-term debt	55.0	400.0
Total current liabilities	**460.0**	**733.7**
Long-term debt - net of current maturities	858.2	1,088.9
Long-term debt payable to CenterPoint Energy	1,343.0	693.0
Total long-term debt	**2,201.2**	**1,781.9**
Deferred Credits & Other Liabilities		
Deferred income taxes	645.7	530.6
Regulatory liabilities	970.4	966.3
Deferred credits & other liabilities	255.6	248.6
Total deferred credits & other liabilities	**1,871.7**	**1,745.5**
Commitments & Contingencies (Notes 8-10)		
Common Shareholder's Equity		
Common stock (no par value)	1,163.4	1,033.4
Retained earnings	1,125.7	1,008.5
Total common shareholder's equity	**2,289.1**	**2,041.9**
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	**$ 6,822.0**	**$ 6,303.0**

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

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

	Year Ended December 31, 2020	2019	2018
OPERATING REVENUES			
Gas utility	$ 868.0	$ 862.4	$ 857.8
Electric utility	554.5	570.2	582.5
Other	0.1	0.4	0.3
Total operating revenues	**1,422.6**	**1,433.0**	**1,440.6**
OPERATING EXPENSES			
Cost of gas sold	241.2	279.8	316.7
Cost of fuel & purchased power	147.4	165.9	186.2
Other operating	375.8	428.8	355.0
Depreciation & amortization	286.4	269.0	250.1
Taxes other than income taxes	73.6	67.7	63.9
Total operating expenses	**1,124.4**	**1,211.2**	**1,171.9**
OPERATING INCOME	**298.2**	**221.8**	**268.7**
Other income - net	20.3	21.7	36.0
Interest expense	81.9	87.0	81.4
INCOME BEFORE INCOME TAXES	**236.6**	**156.5**	**223.3**
Income taxes	48.4	8.5	32.7
NET INCOME	**$ 188.2**	**$ 148.0**	**$ 190.6**

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

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

	Year Ended December 31, 2020	2019	2018
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 188.2	$ 148.0	$ 190.6
Adjustments to reconcile net income to cash from operating activities:			
Depreciation & amortization	286.4	269.0	250.1
Deferred income taxes & investment tax credits	87.6	33.4	20.7
Provision for uncollectible accounts	5.5	7.2	6.5
Expense portion of pension & postretirement benefit cost	11.7	14.3	4.2
Other non-cash items - net	13.2	4.5	3.5
Changes in working capital accounts:			
Accounts receivable & accrued unbilled revenue	(38.6)	14.3	14.5
Inventories	(8.5)	(20.2)	25.5
Recoverable/refundable fuel & natural gas costs	(1.0)	5.7	12.3
Prepayments & other current assets	(12.7)	7.1	(1.7)
Account payable	93.3	9.2	(59.7)
Accrued liabilities	(8.6)	(30.5)	26.7
Employer contributions to pension & postretirement plans	(3.3)	(17.1)	(8.4)
Changes in noncurrent assets	(57.6)	(50.9)	(36.9)
Changes in noncurrent liabilities	(18.7)	(70.6)	(24.5)
Net cash from operating activities	**536.9**	**323.4**	**423.4**
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from:			
Long-term debt, net of issuance costs	—	—	299.3
Long-term debt from CenterPoint Energy	650.0	693.0	—
Capital contribution from parent	130.0	54.2	101.7
Requirements for:			
Dividends to parent	(71.0)	(47.5)	(127.9)
Retirement of long-term debt	(55.0)	(568.0)	(100.0)
Current maturities of long-term debt	(345.0)	—	—
Net change in commercial paper	(175.8)	101.6	(12.9)
Net cash from financing activities	**133.2**	**233.3**	**160.2**
CASH FLOWS FROM INVESTING ACTIVITIES			
Proceeds from:			
Company-owned life insurance	1.7	20.2	—
Sale of investments	—	34.4	—
Requirements for:			
Capital expenditures, excluding AFUDC equity	(676.8)	(584.4)	(570.9)
Purchase of investments	—	(38.5)	—
Other-net	2.3	—	—
Net cash from investing activities	**(672.8)**	**(568.3)**	**(570.9)**
Net change in cash & cash equivalents	(2.7)	(11.6)	12.7
Cash & cash equivalents at beginning of period	10.9	22.5	9.8
Cash & cash equivalents at end of period	$ 8.2	$ 10.9	$ 22.5

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

VECTREN UTILITY HOLDINGS, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY
(In millions)

	Common Stock	Retained Earnings	Total
Balance at January 1, 2018	**$ 877.5**	**$ 845.3**	**$ 1,722.8**
Net income		190.6	190.6
Common stock:			
Additional capital contribution	101.7		101.7
Dividends		(127.9)	(127.9)
Balance at December 31, 2018	**979.2**	**908.0**	**1,887.2**
Net income		148.0	148.0
Common stock:			
Additional capital contribution	54.2		54.2
Dividends		(47.5)	(47.5)
Balance at December 31, 2019	**1,033.4**	**1,008.5**	**2,041.9**
Net income		188.2	188.2
Common stock:			
Additional capital contribution	130.0		130.0
Dividends		(71.0)	(71.0)
Balance at December 31, 2020	**$ 1,163.4**	**$ 1,125.7**	**$ 2,289.1**

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

1. Organization and Nature of Operations

Vectren Utility Holdings, Inc. (the Company, Utility Holdings or VUHI), an Indiana corporation, was formed on March 31, 2000, to serve as the intermediate holding company for Vectren Corporation's (Vectren or the Company's parent) three operating public utilities: Indiana Gas Company, Inc. (Indiana Gas or Vectren Energy Delivery of Indiana - North or CenterPoint Energy Indiana North), Southern Indiana Gas and Electric Company (SIGECO or Vectren Energy Delivery of Indiana - South or CenterPoint Energy Indiana South), and Vectren Energy Delivery of Ohio, Inc. (VEDO or CenterPoint Energy Ohio). Herein, 'the Company' may also refer to Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Inc. and/or Vectren Energy Delivery of Ohio, Inc. The Company also has other assets that provide information technology and other services to the three utilities. Vectren, a wholly owned subsidiary of CenterPoint Energy, Inc. (collectively with its subsidiaries, CenterPoint Energy) and an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana, and was organized on June 10, 1999. Both Vectren and the Company are holding companies as defined by the Energy Policy Act of 2005 (Energy Act).

At December 31, 2020, Indiana Gas provided energy delivery services to 625,662 natural gas customers located in central and southern Indiana. SIGECO provided energy delivery services to 149,289 electric customers and 114,125 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 provided energy delivery services to 328,317 natural gas customers located near Dayton in west-central Ohio.

Merger with CenterPoint Energy

On February 1, 2019 (Merger Date), pursuant to the Merger Agreement, Vectren consummated the previously announced a merger with CenterPoint Energy and was acquired for approximately $6 billion in cash (the Merger). Each share of Vectren common stock issued and outstanding immediately prior to the closing was canceled and converted into the right to receive $72.00 in cash per share, without interest. At the closing, each stock unit payable in Vectren common stock or whose value was determined with reference to the value of Vectren common stock, whether vested or unvested, was canceled with cash consideration paid in accordance with the terms of the Merger Agreement. These amounts did not include a stub period cash dividend of $0.41145 per share, which was declared, with CenterPoint Energy consent, by Vectren's board of directors on January 16, 2019, and paid to Vectren stockholders as of the Merger Date.

Pursuant to the Merger Agreement and immediately subsequent to the close of the Merger, Vectren cash settled all outstanding share-based awards issued prior to the Merger Date by Vectren to its employees. As a result, VUHI recorded an incremental cost of $26 million in *Other operating expenses* on its *Consolidated Statements of Income* during the year ended December 31, 2019 for its share of allocated costs.

Subsequent to the close of the Merger, VUHI recognized severance totaling $41 million to employees terminated in 2019, inclusive of change of control severance payments to executives of Vectren under existing agreements, and which is included in *Other operating expenses* on its *Consolidated Statements of Income* during the year ended December 31, 2019.

In connection with the Merger, VUHI made offers to prepay certain outstanding guaranteed senior notes as required pursuant to certain note purchase agreements previously entered into by VUHI. See Note 7 for further details.

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 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.

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 March 8, 2021, 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.

Accounts Receivables and Allowance for Credit Losses

Accounts receivable are recorded at the invoiced amount and do not bear interest. Management reviews historical write-offs, current available information, and reasonable and supportable forecasts to estimate and establish allowance for credit losses. Account balances are charged off against the allowance when management determines it is probable the receivable will not be recovered. See Note 5 for further information about regulatory deferrals of bad debt expense related to COVID-19.

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 of Long-Lived Assets
The Company periodically evaluates long-lived assets, including property, plant and equipment, and specifically identifiable intangibles subject to amortization, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. For rate regulated businesses, recoverability of long-lived assets is assessed by determining if a capital disallowance from a regulator is probable through monitoring the outcome of rate cases and other proceedings. No long-lived asset or intangible asset impairments were recorded in 2020, 2019, or 2018.

<u>Goodwill</u>
Goodwill recorded on the *Consolidated Balance Sheets* results from the Company's 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 performs goodwill impairment tests at least annually and evaluates goodwill when events or changes in circumstances indicate that its carrying value may not be recoverable. The Company recognizes a goodwill impairment by the amount a reporting unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill within that reporting unit. The Company includes deferred tax assets and liabilities within its reporting unit's carrying value for the purposes of annual and interim impairment tests, regardless of whether the estimated fair value reflects the disposition of such assets and liabilities. No goodwill impairments were recorded in 2020, 2019,or 2018.

<u>Regulation</u>
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. SIGECO is subject to FERC regulation as an electric public utility. 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 regulatory 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 the ability to recognize new regulatory assets associated with its regulated utility operations. The Company records pre-tax expense for (i) probable disallowances of capital investments and (ii) customer refund obligations and costs deferred in regulatory assets when recovery of such amounts

is no longer considered probable. Given the current regulatory environment in its jurisdictions, the Company believes such accounting for regulatory assets and regulatory liabilities 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 collected in advance of expenditure as a *Regulatory liability* because the liability does not meet the threshold of an asset retirement obligation.

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 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.

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, other than NPNS, is not material to these financial statements.

Income Taxes
On February 1, 2019, Vectren became a wholly-owned subsidiary of CenterPoint Energy and became included in CenterPoint Energy's consolidated federal income tax return. Vectren and certain subsidiaries are also included in various unitary or consolidated state income tax returns with CenterPoint Energy. In other state jurisdictions, Vectren and certain subsidiaries continue to file separate state tax returns. The Company calculates the provision for income taxes and income tax liabilities for each jurisdiction using a separate return method.

The Company uses the asset and liability method of accounting for deferred income taxes. Deferred income tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. A valuation allowance is established against deferred tax assets for which management believes realization is not considered to be more likely than not. The Company recognizes interest and penalties as a component of *income tax expense (benefit)*, as applicable, in their respective *Consolidated Statements of Income*.

On December 22, 2017, President Trump signed into law comprehensive tax reform legislation informally called the Tax Cuts and Jobs Acts, or TCJA, which resulted in significant changes to federal tax laws effective January 1, 2018. See Note 6 for further discussion of the impacts of tax reform implementation.

To the extent certain excess deferred income taxes of the Company’s rate-regulated subsidiaries may be recoverable or payable through future rates, regulatory assets and liabilities have been recorded, respectively.

Investment tax credits are deferred and amortized to income over the approximate lives of the related property.

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 at least a net hourly position, meaning net purchases within that interval are recorded on the Company's *Consolidated Statements of Income* in Utility natural gas, fuel and purchased power, and net sales within that interval are recorded on the Company's *Consolidated Statements of Income* in 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.

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 $30.3 million in 2020, $30.3 million in 2019, and $31.1 million in 2018. Expense associated with excise and utility receipts taxes are recorded as a component of *Taxes other than income taxes*.

Reportable Segments

The Company’s chief operating decision maker is the Chief Executive Officer of the Company. Beginning on February 1, 2019, upon close of the Merger, the Company aligned its operating segments with CenterPoint Energy. During 2019, the measure of profitability used by management for all operations became operating income. During 2020, the Company’s CODM views net income as the measure of profit or loss for the reportable segments rather than the previous measure of operating income

Prior period segment results have been recast to reflect management's profitability measure effective during 2020. Net income is the measure of profitability used by management for all operations. See Note 12 for further information.

Fair Value Measurements

Certain assets and liabilities are valued and disclosed at fair value. 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 accordance with ASC 606, revenue is recognized when a customer obtains control of promised goods or services. The amount of revenue recognized reflects the consideration to which the Company expects to be entitled to receive in exchange for these goods or services.

The Company determines that disaggregating revenue into certain 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 12, include: Natural Gas and Electric.

The Company provides commodity service to customers at rates, charges, and terms and conditions included in tariffs approved by regulators. The Company's utilities bill customers 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 Company's revenues are not subject to significant returns, refunds, or warranty obligations.

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

(In millions)	Year Ended December 31, 2020	2019	2018
Natural Gas			
Residential	$ 593.0	$ 578.9	$ 575.2
Commercial	189.9	194.3	196.6
Industrial	82.6	82.0	78.3
Other	2.5	7.2	7.7
Total Natural Gas	**$ 868.0**	**$ 862.4**	**$ 857.8**
Electric			
Residential	$ 209.1	$ 210.4	$ 210.2
Commercial	144.3	148.1	149.3
Industrial	153.2	159.9	162.1
Other	47.9	51.8	60.9
Total Electric	**$ 554.5**	**$ 570.2**	**$ 582.5**

Contract Balances

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

Remaining Performance Obligations

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

The Company adopted ASU 2016-13, Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments and all related amendments on January 1, 2020 using a modified retrospective method. ASU 2016-13 replaces the “incurred loss” model with a CECL model for financial assets measured at amortized cost and for certain off-balance sheet credit exposures. Adoption of this standard did not have a material impact on the Company's’ consolidated financial statements, and the Company had no material changes in its methodology to recognize losses on financial assets that fall under the scope of Topic 326.

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, 2020		At December 31, 2019	
	Original Cost	Depreciation Rates as a Percent of Original Cost	Original Cost	Depreciation Rates as a Percent of Original Cost
Gas utility plant	$ 4,986.1	3.3 %	$ 4,636.3	3.4 %
Electric utility plant	3,249.1	3.3 %	3,077.3	3.3 %
Common utility plant	71.5	3.6 %	70.8	3.5 %
Construction work in progress	212.2	—	155.9	—
Asset retirement obligations	121.3	—	125.4	—
Total original cost	**$ 8,640.2**		**$ 8,065.7**	

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, 2020, is $194.6 million with accumulated depreciation totaling $145.7 million. AGC and SIGECO share equally in the cost of operation and output of the unit. SIGECO's share of operating costs is included in *Other operating expenses* in the *Consolidated Statements of Income*.

Nonutility Plant, net of accumulated depreciation and amortization follows:

(In millions)	At December 31, 2020	At December 31, 2019
Computer hardware & software	$ 166.3	$ 145.1
Land & buildings	32.5	31.9
All other	4.7	4.7
Nonutility plant - net	**$ 203.5**	**$ 181.7**

Nonutility plant is presented net of accumulated depreciation and amortization of $312.4 million and $323.9 million as of December 31, 2020 and 2019, respectively. Depreciable lives range from 6 to15 years for computer hardware & software and 30 to 40 years for buildings. For the years ended December 31, 2020 and 2019, the Company capitalized interest totaling $0.0 million and $2.7 million, respectively.

5. Regulatory Assets & Liabilities

Regulatory Assets

Regulatory assets consist of the following:

	At December 31,	
(In millions)	2020	2019
Future amounts recoverable from ratepayers related to:		
Net deferred income taxes	$ 8.6	$ 7.0
Asset retirement obligations & other	48.2	59.1
	56.8	66.1
Amounts deferred for future recovery related to:		
Indiana cost recovery riders	133.1	97.5
Ohio cost recovery riders	51.0	59.3
	184.1	156.8
Amounts currently recovered in customer rates related to:		
Indiana authorized trackers	107.6	99.4
Ohio authorized trackers	38.6	7.9
Ohio authorized cost deferrals	94.3	95.8
Loss on reacquired debt & hedging costs	36.7	40.7
	277.2	243.8
Total regulatory assets	**$ 518.1**	**$ 466.7**

Of the $277.2 million currently being recovered in customer rates, $94.3 million related to Ohio deferrals is earning a return. The weighted average recovery period of regulatory assets currently being recovered in base rates, not earning a return, which totals $36.2 million, is 14 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 future recovery is probable.

Regulatory assets for asset retirement obligations, see Note 10 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 Company reached a settlement agreement with the intervening parties whereby the costs would be recovered as requested in the petition filed with the IURC on August 14, 2019. On May 13, 2020, the IURC approved the settlement agreement in full. On October 28, 2020, the IURC approved the Company's ECA proceeding, which included the initiation of recovery of the federally mandated project costs.

Regulatory Liabilities

At December 31, 2020 and 2019, the Company had regulatory liabilities of $970.4 million and $966.3 million, respectively, of which $583.8 million and $548.1 million related to cost of removal obligations and $385.6 million and $416.9 million related to regulatory liability associated with TCJA, at December 31, 2020 and 2019, 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.

COVID-19 Regulatory Matters

Governors, public utility commissions and other authorities in the states in which the Company operate have issued a number of different orders related to the COVID-19 pandemic, including orders addressing customer non-payment and disconnection.
The IURC and PUCO have authorized utilities to employ deferred accounting authority for certain COVID-19 related costs which ensure the safety and health of customers, employees, and contractors, that would not have been incurred in the normal course of business. Additionally, the IURC and PUCO have either (1) issued orders to record a regulatory asset for incremental bad debt expenses related to COVID-19, including costs associated with the suspension of disconnections and payment plans or (2)

provided authority to recover bad debt expense through an existing tracking mechanism. The Company has recorded incremental uncollectible receivables to the associated regulatory asset of $2.5 million , as of December 31, 2020.

6. Transactions with Other Vectren Companies and Affiliates

Vectren Infrastructure Services Corporation (VISCO)
On April 9, 2020, Vectren closed on a transaction to sell its Infrastructure Services businesses which provided underground pipeline construction and repair services. VISCO's customers included the Company's utilities and fees incurred by the Company totaled:

(In millions)	2020(1)	2019	2018
Pipeline construction and repair services(2)	$ 54.7	$ 149.7	$ 140.8

(1) Represents charges for the period, January 1, 2020 until the closing of the sale of VISCO.

(2) Amounts owed to VISCO are included in Payable to other Vectren companies until the closing of the sale of VISCO.

Support Services & Purchases
Affiliates of CenterPoint Energy and Vectren provide corporate and general and administrative services to the Company and allocates certain costs to the Company. These services are billed to the Company at actual cost, either directly or as an allocation using various allocators, including number of employees, number of customers and/or the level of payroll, revenue contribution and capital expenditures. Affiliates of CenterPoint Energy provide other miscellaneous services, including geographic services and other management support. These services are billed at actual cost, and the charges are not necessarily indicative of what would have been incurred had CenterPoint Energy's subsidiaries not been affiliates. Amounts owed for support services and purchases at December 31, 2020 and 2019 are included in *Payables to other Vectren companies* and *Affiliated payables to CenterPoint Energy.*

Additionally, CenterPoint Energy, through its energy service subsidiary divested in June 2020, sold natural gas to Electric for use in electric generation activities. Contracts for natural gas were executed in a competitive bidding process and are reflective of what would have been incurred had CenterPoint Energy not been an affiliate.

(In millions)	2020(1)	2019	2018
Affiliate natural gas expense (1)	$ 0.7	$ 1.1	$ —
Corporate allocations (2)	$ 51.4	$ 91.8	$ 52.7

(1) Amounts charged for natural gas are included primarily in *Cost of fuel and purchased power*.

(2) The allocated costs in 2019 include $21.7 million of severance and $25.9 million of stock-based compensation as a result of the Merger with CenterPoint Energy. The allocated costs in 2019 and 2020 also include allocations from CenterPoint Energy for corporate service charges. Amounts charged for corporate allocations are reflected primary in *Other Operating*.

Retirement Plans & Other Postretirement Benefits
At December 31, 2020, the Company's parent maintains three closed qualified defined benefit pension plans (Vectren Corporation Non-Bargaining Retirement Plan, The Indiana Gas Company, Inc. Bargaining Unit Retirement Plan, Pension Plan for Hourly Employees of Southern Indiana Gas and Electric Company), a nonqualified supplemental executive retirement plan (SERP), and a postretirement benefit plan. The defined benefit pension plans and postretirement benefit plan, which cover the Company's 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 Company's current and former employees comprise the vast majority of the participants and retirees covered by these plans.

The Company's parent satisfies the future funding requirements for funded plans and the payment of benefits for unfunded plans from general corporate assets and, as necessary, relies on the Company to support the funding of these obligations. However, the Company has no contractual funding obligation to the plans. The Company did not make a contribution in 2020 and 2019 to the Company's parent for the deferred benefit and pension plans. The Company contributed $3.3 million in 2020 and $17.1 million in 2019 to the Company's parent for SERP and post retirement benefit plans. The combined funded status of Vectren's defined benefit pension plans was approximately 92 percent and 90 percent at December 31, 2020 and 2019, respectively.

The Company's parent allocates retirement plan and other postretirement benefit plan periodic cost calculated pursuant to US GAAP to its subsidiaries, which is also how the Company’s rate regulated utilities recover retirement plan periodic costs through base rates. Periodic costs are charged to the Company following a labor cost allocation methodology and results in retirement costs being allocated to both operating expense and capital projects. For the years ended December 31, 2020, 2019, and 2018, costs totaling $9.5 million, $16.2 million and $8.2 million, respectively, were charged to the Company.

Any difference between the Company's funding requirements to the Company's parent and allocated periodic costs is recognized by the Company as an intercompany asset or liability. The allocation methodology to determine the intercompany funding requirements from the subsidiaries to Vectren is consistent with FASB guidance related to "multiemployer" benefit accounting. Neither plan assets nor plan obligations as calculated pursuant to GAAP by the Company's parent are allocated to individual subsidiaries.

As of December 31, 2020 and 2019, the Company has $46.1 million, and $54.7 million, respectively, included in *Other assets* representing defined benefit funding by the Company to the Company's parent that is yet to be reflected in costs. As of December 31, 2020 and 2019, the Company has $36.6 million and $39.3 million, respectively, included in *Deferred credits & other liabilities* representing costs related to other postretirement benefits charged to the Company that is yet to be funded to the Company's parent. The Company's labor allocation methodology is used to compute the Company's funding of the defined benefit retirement and other postretirement plans to the Company's parent, which is consistent with the regulatory ratemaking processes of the Company's subsidiaries.

Share-Based Incentive Plans & Deferred Compensation Plans
The Company does not have share-based compensation plans separate from Vectren or CenterPoint Energy. The Company recognizes its allocated portion of costs related to share-based incentive plans and deferred compensation plans in accordance with FASB guidance and to the extent these awards are expected to be settled in cash that liability is pushed down to the Company. As of December 31, 2020 and 2019, $5.2 million and $4.4 million, respectively, is included in *Accrued liabilities and Deferred credits & other liabilities* and represents deferred compensation obligations that are yet to be funded in the plan. Subsequent to the February 1, 2019 completion of the Merger, and pursuant to the Merger Agreement, all the share-based awards of Vectren have been settled and a majority of its deferred compensation liabilities have been settled.

Cash Management Arrangements
The Company participates in the centralized cash management program with affiliates of Vectren and has long-term borrowing arrangements with CenterPoint Energy. See Note 7 for further information regarding intercompany borrowing arrangements.

Income Taxes
The Company does not file federal or state income tax returns separate from those filed by its parent, Vectren or CenterPoint Energy. As of February 2, 2019, the Company's parent is included in CenterPoint Energy's consolidated U.S. federal income tax return. Vectren and/or certain of its subsidiaries file income tax returns in various states. Pursuant to a tax sharing agreement and for financial reporting purposes, Vectren subsidiaries record income taxes on a separate company basis. The Company's allocated share of tax effects resulting from it being a part of this consolidated tax group are recorded at the parent company level. Current taxes payable/receivable are settled with the Company's parent in cash quarterly and after filing the consolidated federal and state income tax returns.

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 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.

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 Tax Cuts and Jobs Act (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, 2020 and 2019, the Company has $385.6 million and $397.5 million, respectively, in liabilities associated with excess deferred income taxes.

In Indiana, the IURC approved a 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, a rate reduction to the Company's current rates and charges was effective upon the Company receiving approval of new base rates effective on September 1, 2019. In January 2019, the Company filed an application with PUCO in compliance with its October 2018 order requiring utilities to file for a request to adjust rates to reflect the impact of the TCJA, requesting authority to implement a Tax Credit and Savings Rider (TCSR) to flow back to customers the tax benefits realized under the TCJA, including the refund of excess deferred taxes and regulatory liabilities. An order was received July 1, 2020; however, it did not resolve Component D of the TCJA case. As of December 31, 2020, the Company still awaits a ruling on this portion.

The components of income tax expense and amortization of investment tax credits follow:

	Year Ended December 31,		
(In millions)	2020	2019	2018
Current:			
Federal	$ (32.3)	$ 2.5	$ 25.4
State	(6.9)	(3.9)	3.8
Total current taxes	**(39.2)**	**(1.4)**	**29.2**
Deferred:			
Federal	63.5	8.6	(1.2)
State	24.7	2.6	1.3
Total deferred taxes	**88.2**	**11.2**	**0.1**
Net investment tax credit deferred / (amortized)	(0.6)	(1.3)	3.4
Total income tax expense	**$ 48.4**	**$ 8.5**	**$ 32.7**

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

	Year Ended December 31,		
	2020	2019	2018
Statutory rate	21.0 %	21.0 %	21.0 %
Federal tax law change impacts	(7.4)	(11.4)	(8.0)
State and local taxes-net of federal benefit	2.3	2.9	2.8
All other - net	4.5	(7.0)	(1.2)
Effective tax rate	**20.4 %**	**5.5 %**	**14.6 %**

Significant components of the net deferred tax liability follow:

	At December 31,	
(In millions)	2020	2019
Noncurrent deferred tax assets:		
U.S. federal charitable contributions carryforwards	$ —	$ 3.3
Regulatory liabilities settled through future rates	86.0	$ 98.0
Total deferred tax assets	$ 86.0	$ 101.3
Noncurrent deferred tax liabilities:		
Depreciation & cost recovery timing differences	$ 646.1	$ 567.1
Regulatory assets recoverable through future rates	9.8	8.4
Employee benefit obligations	4.3	3.8
Deferred fuel costs	25.6	17.5
Other – net	45.9	35.1
Total deferred tax liabilities	$ 731.7	$ 631.9
Net noncurrent deferred tax liability	$ 645.7	$ 530.6

At December 31, 2020 and 2019, investment tax credits totaling $2.8 million and $3.4 million, respectively, are included in *Deferred credits & other liabilities*.

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 $0.6 million and $0.8 million, respectively, at December 31, 2020 and 2019.

The Company's parent and certain of its subsidiaries file income tax returns in the U.S. federal jurisdiction and various states. The Internal Revenue Service (IRS) has concluded examinations of Vectren's U.S. federal income tax return for tax year December 31, 2016 with no adjustments. The State of Indiana, Vectren's primary state tax jurisdiction, has concluded examinations of Vectren's consolidated state income tax returns for tax years through 2017 with no adjustments. The statutes of limitations for assessment of federal income tax and Indiana income tax have expired with respect to tax years through 2016 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 2013 tax year related to the amended federal income tax return expired in 2020. The statutes of limitations for assessment of the 2013 and 2014 tax years related to the amended Indiana income tax returns expired in 2020.

7. Borrowing Arrangements

Long-Term Debt

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

	At December 31,	
(In millions)	2020	2019
Utility Holdings		
Fixed Rate Affiliate Debt		
2028, 3.20%	$ 45.0	45.0
2032, 3.26%	100.0	100.0
2023, 3.72%	93.0	93.0
2035, 3.90%	25.0	25.0
2047, 3.93%	100.0	100.0
2043, 4.25%	70.0	70.0
2045, 4.36%	95.0	95.0
2055, 4.51%	40.0	40.0
2049, 3.42%	125.0	125.0
2050, 3.92%	175.0	—
2025, 1.21%	300.0	—
2030, 1.72%	175.0	—
Fixed Rate Senior Unsecured Notes		
2020, 6.28%	—	100.0
2021, 4.67%	55.0	55.0
2023, 3.72%	57.0	57.0
2026, 5.02%	60.0	60.0
2035, 6.10%	75.0	75.0
2041, 5.99%	35.0	35.0
2042, 5.00%	100.0	100.0
2043, 4.25%	10.0	10.0
2045, 4.36%	40.0	40.0
Variable Rate Term Loans		
2020, current adjustable rate, 2.5125%	—	300.0
Commercial Paper backed by long-term facility	92.4	268.2
Total Utility Holdings	**1,867.4**	**1,793.2**
SIGECO		
First Mortgage Bonds		
2022, 2013 Series C, current adjustable rate .88%, tax-exempt	4.6	4.6
2024, 2013 Series D, current adjustable rate .88%, tax-exempt	22.5	22.5
2025, 2014 Series B, current adjustable rate .88%, tax-exempt	41.3	41.3
2029, 1999 Series, 6.72%	80.0	80.0
2037, 2013 Series E, current adjustable rate .88%, tax-exempt	22.0	22.0
2038, 2013 Series A, current adjustable rate .88%, tax-exempt	22.2	22.2
2043, 2013 Series B, current adjustable rate .88%, tax-exempt	39.6	39.6
2044, 2014 Series A, 4.00%, tax-exempt	22.3	22.3
2055, 2015 Series Mt. Vernon, .875%, tax-exempt	23.0	23.0
2055, 2015 Series Warrick County, .875%, tax-exempt	15.2	15.2
Total SIGECO	**292.7**	**292.7**

	At December 31,	
(In millions)	2020	2019
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**
Total long-term debt payable to CenterPoint Energy	**1,343.0**	**693.0**
Total long-term debt payable to third parties	**913.1**	**1,488.9**
Total long-term debt outstanding	**2,256.1**	**2,181.9**
Current maturities of long-term debt	(55.0)	(400.0)
Unamortized debt premium & discount - net	0.1	—
Total long-term debt-net	**$ 2,201.2**	**$ 1,781.9**

Utility Holdings Borrowing Arrangements

In connection with the Merger, the Company made offers to prepay certain outstanding guaranteed senior notes as required pursuant to certain note purchase agreements. In turn, the Company borrowed $568 million to make the prepayment at the same interest rate and term as the notes being prepaid. The CenterPoint Energy notes are not guaranteed by the Company's subsidiaries.

On September 28, 2020, Utility Holdings issued a 1.72% promissory note due October 1, 2030 to CenterPoint Energy. Total gross and net proceeds to Utility Holdings were $175 million, which were used to repay borrowings under VUHI’s $400 million commercial paper program.

On June 30, 2020, Utility Holdings issued a 1.21% promissory note due July 1, 2025 to CenterPoint Energy. Total gross and net proceeds to Utility Holdings were $300 million, which were used to repay VUHI's $300 million Term Loan.

On April 7, 2020, Utility Holdings issued a 3.92% promissory note due May 1, 2050 to CenterPoint Energy. Total gross and net proceeds to Utility Holdings were $175 million, which were used in part to repay VUHI’s $100 million fixed rate senior unsecured notes and to repay borrowings under VUHI’s $400 million commercial paper program.

On September 10, 2019, the Company issued a 3.42% promissory note due September 15, 2049 to CenterPoint Energy. Total gross and net proceeds to the Company were $125 million, which were used to repay borrowings under the Company's $400 million commercial paper program.

Credit Facilities: The Company had the following revolving credit facilities as of December 31, 2020:

Execution Date	Company	Size of Facility		Draw Rate of LIBOR plus [1]	Financial Covenant Limit on Debt for Borrowed Money to Capital Ratio	Debt for Borrowed Money to Capital Ratio as of December 31, 2020 [2]	Termination Date
		(in millions)					
July 14, 2017	Utility Holdings [3]	$	400	1.125%	65%	49.7%	July 14, 2022

[1] Based on credit ratings as of December 31, 2020.

[2] As defined in the revolving credit facility agreement.

[3] This credit facility was issued by VUHI, is guaranteed by SIGECO, Indiana Gas and VEDO and includes a $10 million swing line sublimit and a $20 million letter of credit sublimit. This credit facility backstops, VUHI's commercial paper program.

Pursuant to the Company's short-term credit facility the Merger represented an event of default. However, the banking partner in the facility waived the event of default. In February 2021, the Company amended and restated its credit facility. See Note 16 for further information.

Term Loans

On July 30, 2018, the Company 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 depending on the Company's credit rating. In addition, the term loan contains a provision 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 the Company's wholly-owned operating companies, SIGECO, Indiana Gas, and VEDO. The Utility Holdings term loan was repaid on September 30, 2020.

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.

In September 2020, the Company completed the remarketing of two series of tax-exempt debt of approximately $38 million, comprised of: (i) $23 million aggregate principal amount of Environmental Improvement Revenue Bonds, Series 2015, issued by the City of Mount Vernon, Indiana, and (ii) $15 million aggregate principal amount of Environmental Improvement Revenue

Bonds, Series 2015, issued by Warrick County, Indiana, that, in each case, were originally issued on September 9, 2015. Both series of revenue bonds originally had an initial term interest rate of 2.375 percent. After the remarketing, each series of revenue bonds have a new term interest rate of 0.875 percent that is fixed through August 31, 2023. Each series of revenue bonds have a final maturity date of September 1, 2055, subject to prior redemption.

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, 2019, certain series of SIGECO bonds, aggregating $185.7 million were subject to mandatory tenders prior to the bonds' final maturities. In 2020, $38.2 million was tendered and remarketed and $147.5 million will be tendered in 2023.

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 2020 sinking fund requirement by this means and, expects to also meet this requirement in 2021 in this manner. Accordingly, the sinking fund requirement is excluded from *Current liabilities* in the *Consolidated Balance Sheets*. At December 31, 2020, $2.1 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 $4.1 billion at December 31, 2020.

Consolidated maturities of third-party long-term debt during the five years following 2020 (in millions) are $55 in 2021, $5 in 2022, $57 in 2023, $23 in 2024, $51 in 2025, and $630 thereafter. Consolidated maturities of affiliated long-term debt, excluding commercial paper backed by the VUHI credit facility that expires in July 2022, during the five years following 2020 (in millions) are $0 in 2021, $0 in 2022, $93 in 2023, $0 in 2024, $300 in 2025, and $950 thereafter.

Debt Guarantees

The Company's outstanding long-term and commercial paper borrowing arrangements are jointly and severally guaranteed by SIGECO, Indiana Gas, and VEDO. The Company's third-party long-term debt outstanding at December 31, 2020, was $524 million.

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, 2020, the Company was in compliance with all debt covenants.

8. Commitments & Contingencies

Commitments

The Company's regulated utilities have both firm and non-firm commitments, some of which are between five and twenty year agreements, to purchase natural gas, 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.

The Company's minimum purchase obligations for these commitments, which have various quantity requirements and duration are $218 million in 2021, $214 million in 2022, $190 million in 2023, $133 million in 2024, $143 million in 2025 and $383 million thereafter.

Letters of Credit
The Company, from time to time, through its subsidiaries, issues letters of credit that support consolidated operations. At December 31, 2020, there were no letters of credit outstanding.

Legal and 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.

9. Regulatory Matters

COVID-19 Regulatory Matters
Governors, public utility commissions and other authorities in Indiana and Ohio have issued a number of different orders related to the COVID-19 pandemic, including orders addressing customer non-payment and disconnection. While certain jurisdictions are subject to mandatory stay-at-home and similar orders, essential businesses and activities are exempted from these orders, including utility operations and maintenance. Accordingly, the Company's crews continue to provide essential service by responding to calls, completing work orders and undertaking other critical work. To protect its customers and employees, the Company has implemented COVID-19 safety precautions. Although the disconnect moratoriums have expired, the Company continues to support those customers who may need payment assistance, arrangements or extensions. The Company continue to monitor developments in this area and adjust our response as guidelines and circumstances may require. Additionally, while the Company has not experienced delays to date due to COVID-19 with respect to its regulatory proceedings, it could experience significant delays in scheduling proceedings or hearings and in obtaining orders from regulatory agencies. See Note 5 for further information.

Indiana Gas Base Rate Case
On December 18, 2020, the Company filed its base rate case with the IURC seeking approval for a revenue increase of approximately $21 million. This rate case filing is required under Indiana TDSIC statutory requirements before the completion of the Company's capital expenditure program, approved in 2014 for investments starting in 2014 through 2020. The revenue increase is based upon a requested ROE of 10.15% and an overall after-tax rate of return of 6.32% on total rate base of approximately $1,611 million. The Company has utilized a projected test year, reflecting its 2021 budget as the basis for the revenue increase requested, and proposes to implement rates in two phases. The first phase of rate implementation will occur as of the date of an order in this proceeding, expected in October 2021, and the second phase of rate implementation will occur at the completion of the test year, as of December 31, 2021. Under Indiana statutory requirements, the IURC has a minimum of 300 days and maximum of 360 days from the date of the filing of the Company's case-in-chief to issue an order.

SIGECO Base Rate Case
On October 30, 2020, and as subsequently amended, the Company filed its base rate case with the IURC seeking approval for a revenue increase of approximately $29 million. This rate case filing is required under Indiana TDSIC statutory requirements before the completion of the Company's capital expenditure program, approved in 2014 for investments starting in 2014 through 2020. The revenue increase is based upon a requested ROE of 10.15% and an overall after-tax rate of return of 5.99% on total rate base of approximately $469 million. The Company has utilized a projected test year, reflecting its 2021 budget as the basis for the revenue increase requested, and proposes to implement rates in two phases. The first phase of rate implementation will occur as of the date of an order in this proceeding, expected in September 2021, and the second phase of rate implementation will occur at the completion of the test year, as of December 31, 2021. Under Indiana statutory requirements, the IURC has a minimum 300 days and maximum of 360 days from the date of the filing of the Company's case- in-chief to issue an order.

Electric Generation Project
The Company must either (i) make substantial investments in its existing generation resources to comply with environmental regulations or (ii) replace its existing generation with new resources. Indiana requires each electric utility to perform and submit an IRP every three years (unless extended) to the IURC that uses economic modeling to consider the costs and risks associated with available resource options to provide reliable electric service for the next 20-year period. On February 20, 2018, the Company filed a petition seeking authorization from the IURC to construct a new 700-850 MW natural gas combined cycle

generating facility to replace the baseload capacity of its existing generation fleet at an approximate cost of $900 million, which included the cost of a new natural gas pipeline to serve the plant.

As a part of this same proceeding, the Company also sought recovery under Indiana Senate Bill 251 of costs to be incurred for environmental investments to be made at its F.B. Culley generating plant to comply with ELG and CCR rules. The F.B. Culley investments, estimated to be approximately $95 million, began 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 customers. Under Indiana Senate Bill 251, the Company sought authority to recover 80% of the approved costs, including a return, using a tracking mechanism, with the remaining 20% of the costs deferred for recovery in the Company's next base rate proceeding.

On April 24, 2019, the IURC issued an order approving the environmental investments proposed for the F.B. Culley generating facility, along with recovery of prior pollution control investments made in 2014. The order denied the proposed gas combined cycle generating facility. The Company has conducted a new IRP, which was submitted to the IURC in June 2020, to identify an appropriate generation resource portfolio that includes the replacement of 730 MW of coal-fired generation facilities with a significant buildout of renewables supported by dispatchable natural gas combustion turbines.

A.B. Brown Ash Pond Remediation

On August 14, 2019, the Company filed a petition with the IURC, seeking approval, as a federally mandated project, for the recovery of costs associated with the clean closure of the A.B. Brown ash pond pursuant to Indiana Senate Bill 251. This project, expected to last approximately 14 years, would result in the full excavation and recycling of the ponded ash through agreements with a beneficial reuse entity, totaling approximately $160 million. Under Indiana Senate Bill 251, the Company seeks authority to recover via a tracking mechanism 80% of the approved costs, with a return on eligible capital investments needed to allow for the extraction of the ponded ash, with the remaining 20% of the costs deferred for recovery in the Company's next base rate proceeding. On December 19, 2019 and subsequently on January 10, 2020, the Company filed a settlement agreement with the intervening parties whereby the costs would be recovered as requested, with an additional commitment by the Company to offset the federally mandated costs by at least $25 million, representing a combination of total cash proceeds received from the ash reuser and total insurance proceeds to be received from the Company's insurers under confidential settlement agreements of litigation filed against the insurers. On May 13, 2020, the IURC approved the settlement agreement in full. On October 28, 2020, the IURC approved the Company's ECA proceeding, which included the initiation of recovery of the federally mandated project costs.

Rate Change Applications

The Company is routinely involved in rate change applications before state regulatory authorities. Those applications include general rate cases, where the entire cost of service of the utility is assessed and reset. In addition, the Company is periodically involved in proceedings to adjust its capital tracking mechanisms in Indiana (CSIA for gas and TDSIC, ECA and CECA for Electric) and Ohio (DRR), its decoupling mechanism in Indiana (SRC for gas), and its energy efficiency cost trackers in Indiana (EEFC for gas and DSMA for electric) and Ohio (EEFR).

The table below reflects significant applications pending or completed during 2020 and to date in 2021 for the Company.

Mechanism	Annual Increase (Decrease) (1) (in millions)	Filing Date	Effective Date	Approval Date	Additional Information
			Indiana South - Gas (IURC)		
CSIA	1	April 2020	July 2020	July 2020	Requested an increase of $13 million to rate base, which reflects a $1 million annual increase in current revenues. 80% of revenue requirement is included in requested rate increase and 20% is deferred until the next rate case. The mechanism also includes refunds associated with the TCJA, resulting in no change to the previous credit provided, and a change in the total (over)/under-recovery variance of $1 million annually.
CSIA	2	October 2020	January 2021	January 2021	Requested an increase of $13 million to rate base, which reflects a $2 million annual increase in current revenues. 80% of revenue requirement is included in requested rate increase and 20% is deferred until the next rate case. The mechanism also includes refunds associated with the TCJA, resulting in no change to the previous credit provided, and a change in the total (over)/under-recovery variance of $(1) million annually.
Rate Case (1)	29	October 2020	September 2021	TBD	See discussion above under SIGECO Base Rate Case.
			Indiana North - Gas (IURC)		
CSIA	4	April 2020	July 2020	July 2020	Requested an increase of $35 million to rate base, which reflects a $4 million annual increase in current revenues. 80% of revenue requirement is included in requested rate increase and 20% is deferred until the next rate case. The mechanism also includes refunds associated with the TCJA, resulting in no change to the previous credit provided, and a change in the total (over)/under-recovery variance of $14 million annually.
CSIA (1)	2	October 2020	January 2021	January 2021	Requested an increase of $32 million to rate base, which reflects a $2 million annual increase in current revenues. 80% of revenue requirement is included in requested rate increase and 20% is deferred until the next rate case. The mechanism also includes refunds associated with the TCJA, resulting in an increase of $(1) million to the previous credit provided, and a change in the total (over)/under-recovery variance of $(6) million annually.
Rate Case (1)	21	December 2020	October 2021	TBD	See discussion above under Indiana Gas Base Rate Case.
			Ohio (PUCO)		

Mechanism	Annual Increase (Decrease) (1) (in millions)	Filing Date	Effective Date	Approval Date	Additional Information
TSCR	N/A	January 2019	July 2020	July 2020	Application to flow back to customers certain benefits from the TCJA. Initial impact reflects credits for 2018 of $(10) million and 2019 of $(9) million, and 2020 of $(7) million, with mechanism that began upon approval from the PUCO effective July 1, 2020.
TSCR	N/A	September 2020	January 2021	January 2021	Application to flow back to customers certain benefits from the TCJA. Impact reflects credits for 2021 of $(7) million and includes a reconciliation through August 31, 2020 of $(14) million.
DRR	9	May 2020	September 2020	December 2020	Requested an increase of $67 million to rate base for investments made in 2019, which reflects a $10 million annual increase in current revenues. A change in (over)/under-recovery variance of $2 million annually is also included in rates.
Indiana Electric (IURC)					
TDSIC	4	February 2020	May 2020	May 2020	Requested an increase of $34 million to rate base, which reflects a $4 million annual increase in current revenues. 80% of revenue requirement is included in requested rate increase and 20% is deferred until next rate case. The mechanism also includes a change in (over)/under-recovery variance of $2 million annually.
ECA	10	May 2020	August 2020	October 2020	Requested an increase of $49 million to rate base, which reflects a $10 million annual increase in current revenues. 80% of the revenue requirement is included in requested rate increase and 20% is deferred until next rate case. The mechanism also includes a change in (over)/under-recovery variance of $4 million annually.
TDSIC	3	August 2020	November 2020	November 2020	Requested an increase of $36 million to rate base, which reflects a $3 million annual increase in current revenues. 80% of the revenue requirement is included in requested rate increase and 20% is deferred until next rate case. The mechanism also includes a change in (over) under-recovery variance of $(1) million annually.
TDSIC(1)	3	February 2021	May 2021	TBD	Requested an increase of $28 million to rate base, which reflects a $3 million annual increase in current revenues. 80% of the revenue requirement is included in requested rate increase and 20% is deferred until next rate case. The mechanism also included a change in (over) under-recovery variance of less than $1 million.
CECA(1)	8	February 2021	TBD	TBD	Reflects an $8 million annual increase in current revenues through a non-traditional rate making approach related to a 50 MW universal solar array placed in service in January 2021.

[1] Represents proposed increases (decreases) when effective date and/or approval date is not yet determined. Approved rates could differ materially from proposed rates.

10. Environmental and Sustainability Matters

Coal Ash Waste Disposal, Ash Ponds and Water

Coal Combustion Residuals Rule
In April 2015, the EPA finalized its CCR Rule, which regulates ash as non-hazardous material under the Resource Conservation and Recovery Act of 1976 (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.

The Company has three ash ponds, two at the F.B. Culley facility (Culley East and Culley West) and one at the A.B. Brown facility. Under the existing CCR Rule, the Company is required to perform integrity assessments, including ground water monitoring, at its F.B. Culley and A.B. Brown generating stations. The ground water studies are necessary 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. The Company's Warrick generating unit is not included in the scope of the CCR Rule as this unit has historically been part of a larger generating station that predominantly serves an adjacent industrial facility. In March 2018, the Company began posting ground water data monitoring reports annually to its public website in accordance with the requirements of the CCR Rule. This data preliminarily indicates potential groundwater impacts very close to the Company's ash impoundments, and further analysis is ongoing. The CCR Rule required companies to complete location restriction determinations by October 18, 2018. The company completed its evaluation and determined that one F.B. Culley pond (Culley East) and the A.B. Brown pond fail the aquifer placement location restriction. As a result of this failure, the Company is required to cease disposal of new ash in the ponds and commence closure of the ponds by April 11, 2021. The Company plans to seek extensions available under the CCR Rule that would allow the Company to continue to use the ponds through October 15, 2023. The inability to take these extensions may result in increased and potentially significant operational costs in connection with the accelerated implementation of an alternative ash disposal system or adversely impact the Company's future operations. Failure to comply with these requirements could also result in an enforcement proceeding including the imposition of fines and penalties. On April 24, 2019, the Company received an order from the IURC approving recovery in rates of costs associated with the closure of the Culley West pond, which completed closure activities under its approved closure plan in December 2020.

In March 2019, the Company entered into agreements with third parties for the excavation and beneficial reuse of the ash at the A.B. Brown ash pond. On August 14, 2019, the Company filed its petition with the IURC for recovery of costs associated with the closure the A.B. Brown ash pond, which would include costs associated with the excavation and recycling of the ponded ash. This petition was subsequently approved by the IURC on May 13, 2020. On October 28, 2020, the IURC approved Indiana Electric’s ECA proceeding, which included the initiation of recovery of the federally mandated project costs. In July 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, and has since reached confidential settlement agreements with its insurers. The proceeds of these settlements will offset costs that have been and will be incurred to close the ponds. The Company continues to refine site specific estimates of closure costs for its 10 acre Culley East pond.

As of December 31, 2020, the Company has recorded an approximate $74 million ARO, which represents the discounted value of future cash flow estimates to close the ponds at A.B. Brown and F.B. Culley. This estimate is subject to change due to the contractual arrangements; continued assessments of the ash, closure methods, and the timing of closure; implications of the Company's generation transition plan; changing environmental regulations; and proceeds received from the settlements in the aforementioned insurance proceeding. In addition to these removal costs, the Company also anticipates equipment purchases of between $60 million and $80 million to complete the A.B. Brown closure project.

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 the Company's water discharge permits, in 2017 the IDEM issued final renewals for the 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, which have been completed, 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 U.S. President’s 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, the EPA finalized a rule postponing certain interim compliance dates by two years, but did not postpone final compliance deadline of December 31, 2023. On April 12, 2019, the U.S. Court of Appeals for the Fifth Circuit vacated and remanded portions of the ELG that selected impoundment as the best available technology for legacy wastewater and leachate. On October 13, 2020, the EPA finalized revisions to the ELG rule, which established a two-year extension of the compliance deadline for the prohibition of wet sluicing of bottom ash. However, the ELG rule did not establish alternative deadlines for the prohibition of wet sluicing of fly ash, and the most recent revision to the CCR rule confirmed that ash ponds must commence closure no later than October 2023. As a result, CenterPoint Energy does not currently anticipate any changes to its current compliance plans based upon this most recent ELG update.

Cooling Water Intake Structures
Section 316 of the federal Clean Water Act requires steam electric generating facilities use “best technology available” to minimize adverse environmental impacts on a body of water. In May 2014 EPA finalized a regulation requiring installation of best technology available (BTA) to mitigate impingement entrainment of aquatic species in cooling water intake structures. The Company is currently completing the required ecological studies and anticipates timely compliance in 2021-2022.

Climate Change and Carbon Strategy

Clean Power Plan and Affordable Clean Energy (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. The final rule was published in the Federal Register on October 23, 2015, and that action was immediately followed by litigation ultimately resulting in the U.S. Supreme Court staying implementation of the rule.

In August 2018, the EPA proposed a CPP replacement rule, the ACE Rule, which was finalized in July 2019 and required states to implement a program of energy efficiency improvement targets for individual coal-fired electric generating units. On January 19, 2021, the ACE Rule was struck down by the U.S. District Court of Appeals for the D.C. Circuit. We are currently unable to predict whether the Biden Administration will continue its defense of the CPP or ACE rules, or what a new replacement rule would look like.

Impact of Legislative Actions & Other Initiatives
At this time, compliance costs and other effects associated with reductions in greenhouse gases (GHG) emissions or obtaining renewable energy sources remain uncertain. Moreover, the Biden Administration has moved to reenter the Paris Climate Agreement. While the requirements of a new GHG replacement rule remain uncertain, the Company will continue to monitor regulatory and legislative activity regarding GHG emission standards that may affect its electric generating units.

Manufactured Gas Plants
Vectren and its predecessors operated manufactured gas plants in the past. The Company has accrued estimated costs for investigation, remediation, and ground water monitoring that it expects to incur to fulfill its respective obligations using assumptions based on actual costs incurred, the timing of expected future payments and inflation factors, among others. While the Company has recorded all costs which it presently is obligated 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 potentially responsible parties (PRP) or insurance recovery.

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. As of December 31, 2020 and 2019, approximately $5.1 million and $4.5 million, respectively of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

11. Fair Value Measurements

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

	At December 31,			
	2020		2019	
(In millions)	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt payable to third parties	$ 820.8	$ 977.5	$ 1,220.7	$ 1,329.9
Long-term debt payable to CenterPoint Energy	1,343.0	1,499.3	693.0	717.0
Commercial Paper [1]	92.4	92.4	268.2	268.2
Cash & cash equivalents	8.2	8.2	10.9	10.9
Natural gas purchase instrument liabilities [2]	9.9	9.9	22.2	22.2
Interest rate swap liabilities [3]	20.0	20.0	9.8	9.8

[1] Presented in "Long-term debt" 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.* The interest rate swaps contain provisions that require the Company to maintain an investment grade credit rating on its long-term unsecured unsubordinated debt from S&P and Moody's. If the Company's debt were to fall below investment grade, it would be in violation of these provisions, and the counterparties to the interest rate swaps could request immediate payment. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position on December 31, 2020, is approximately $20 million for which the Company has posted collateral of $6.5 million in the normal course of business. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2020, the Company would be required to post an additional $3.5 million of collateral to its counterparties. The maximum collateral required if further escalating collateral is triggered would equal the net liability position.

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 7, 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.

12. Segment Reporting

The Company segregates its operations into two reportable segments: 1) Natural Gas and 2) Electric. As of January 1, 2020, the Company's CODM views net income as the measure of profit or loss for the reportable segments rather than the previous measure of operating income. Certain prior year amounts have been reclassified to conform to the current year presentation. See Note 2 for further information.

As of December 31, 2020, reportable segments are as follows:

- The Natural Gas segment provides natural gas distribution and transportation services to nearly two-thirds of Indiana and to west central Ohio.
- The Electric segment provides electric generation, transmission and 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.

Other operations provides information technology and other support services to the operating segments, owns shared company assets that are charged to the operating segments, as well as unallocated corporate expenses such as Merger-related costs, advertising and certain charitable contributions, among other activities, that benefit the Company’s other operating segments.

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

(In millions)	Year Ended December 31, 2020	2019	2018
Revenues			
Natural Gas	$ 868.0	$ 862.4	$ 857.8
Electric	554.5	570.2	582.5
Other Operations	0.1	0.4	0.3
Total revenues	**$ 1,422.6**	**$ 1,433.0**	**$ 1,440.6**
Profitability Measure - Net Income			
Natural Gas	$ 120.0	$ 72.6	$ 99.3
Electric	73.1	58.0	76.2
Other Operations	(4.9)	17.4	15.1
Total net income	**$ 188.2**	**$ 148.0**	**$ 190.6**
Depreciation & Amortization			
Natural Gas	$ 156.2	$ 142.8	$ 130.1
Electric	103.9	99.7	91.8
Other Operations	26.3	26.5	28.2
Total depreciation & amortization	**$ 286.4**	**$ 269.0**	**$ 250.1**

(In millions)	Year Ended December 31, 2020	2019
Capital Expenditures		
Natural Gas	$ 365.3	$ 348.2
Electric	260.1	204.1
Other Operations	48.6	6.5
Non-cash costs & changes in accruals	2.8	25.6
Total capital expenditures	**$ 676.8**	**$ 584.4**

(In millions)	At December 31, 2020	2019
Assets		
Natural Gas	$ 4,337.6	$ 4,053.9
Electric	2,254.8	2,053.0
Other Operations, net of eliminations	229.6	196.1
Total assets	**$ 6,822.0**	**$ 6,303.0**

13. Additional Balance Sheet & Operational Information

Inventories consist of the following:

(In millions)	At December 31, 2020	2019
Gas in storage – at LIFO cost	$ 36.9	$ 39.5
Materials & supplies	38.7	37.9
Coal & oil for electric generation - at average cost	43.7	33.4
Other	1.4	1.4
Total inventories	**$ 120.7**	**$ 112.2**

Based on the average cost of gas purchased during December 2020, the cost of replacing inventories carried at LIFO cost was less than carrying value at December 31, 2020 by $8.0 million. Based on the average cost of gas purchased during December 2019, the cost of replacing inventories carried at LIFO cost was less than the carrying value at December 31, 2019 by $8.0 million.

Prepayments & other current assets in the Consolidated Balance Sheets consist of the following:

	At December 31,	
(In millions)	2020	2019
Prepaid gas delivery service	$ 16.0	$ 19.4
Prepaid taxes	16.9	2.5
Other prepayments & current assets	8.5	5.0
Total prepayments & other current assets	**$ 41.4**	**$ 26.9**

Other investments in the Consolidated Balance Sheets consist of the following:

	At December 31,	
(In millions)	2020	2019
Cash surrender value of life insurance policies	$ 16.7	$ 15.4
Other	0.3	0.4
Total other investments	**$ 17.0**	**$ 15.8**

Accrued liabilities in the Consolidated Balance Sheets consist of the following:

	At December 31,	
(In millions)	2020	2019
Refunds to customers & customer deposits	$ 39.6	$ 44.3
Accrued taxes	50.7	47.4
Accrued interest	12.6	13.8
Accrued salaries & other	25.7	36.6
Total accrued liabilities	**$ 128.6**	**$ 142.1**

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

(In millions)	2020	2019
Asset retirement obligation, January 1	$ 159.9	$ 115.9
Accretion	4.2	5.7
Changes in estimates, net of cash payments	(4.1)	38.3
Asset retirement obligation, December 31	**$ 160.0**	**$ 159.9**

Other – net in the Consolidated Statements of Income consists of the following:

	Year Ended December 31,		
(In millions)	2020	2019	2018
AFUDC - borrowed funds	$ 16.2	$ 26.3	$ 29.7
AFUDC - equity funds	7.5	4.1	3.4
Nonutility plant capitalized interest	—	0.2	1.2
Pension Settlement Charges	(5.4)	(10.6)	(1.6)
Other income	2.0	1.7	3.3
Total other – net	**$ 20.3**	**$ 21.7**	**$ 36.0**

Supplemental Cash Flow Information:

	Year Ended December 31,		
(In millions)	2020	2019	2018
Cash paid (received) for:			
Interest	$ 79.4	$ 85.2	$ 83.7
Income taxes	(24.6)	(1.9)	44.4

As of December 31, 2020 and 2019, the Company has accruals related to utility and nonutility plant purchases totaling approximately $7.7 million and $17.3 million, respectively.

14. Impact of Recently Issued Accounting Standards

The following table provides an overview of recently adopted or issued accounting pronouncements applicable to the Company, unless otherwise noted:

Recently Adopted Accounting Standards

ASU Number and Name	Description	Date of Adoption	Financial Statement Impact upon Adoption
ASU 2016-13- Financial Instruments-Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments	This standard, including standards amending this standard, requires a new model called CECL to estimate credit losses for (1) financial assets subject to credit losses and measured at amortized cost and (2) certain off-balance sheet credit exposures. Upon initial recognition of the exposure, the CECL model requires an entity to estimate the credit losses expected over the life of an exposure based on historical information, current information and reasonable and supportable forecasts, including estimates of prepayments. ***Transition method***:modified retrospective	January 1, 2020	The Company adopted the standard and there was no impact on results of operations and cash flows. See Note 3 for more information.
ASU 2019-12: Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes	This standard simplifies accounting for income taxes by eliminating certain exceptions to the guidance for intraperiod tax allocation, the methodology for calculating income taxes in an interim period and the recognition of deferred tax liabilities for outside basis differences. It also simplifies aspects of the accounting for franchise taxes that are partially based on income and enacted changes in tax laws or rates and clarifies the accounting for transactions that result in a step-up in the tax basis of goodwill. ***Transition method***: prospective for all amendments that apply to the Company.	January 1, 2020	Upon adoption, the Company is not required to apply the intraperiod tax allocation exception when there is a current-period loss from continuing operations. Accordingly, the Company determined the tax effect of income from continuing operations without considering the tax effects of items that are not included in continuing operations (i.e., discontinued operations). Additionally, the Company is no longer required to limit the year-to-date tax benefit recognized when the year-to-date benefit exceeds the anticipated full year benefit.

Management believed that other recently adopted standards and recently issued standards that are not yet effective will not have a material impact on the Company's financial position, results of operations or cash flows upon adoption.

15. Lease

The Company adopted ASC 842, Leases, and all related amendments on January 1, 2019 using the modified retrospective transition method and elected not to recast comparative periods in the year of adoption as permitted by the standard. There was no adjustment to retained earnings as a result of transition. As a result, disclosures for periods prior to adoption will be presented in accordance with accounting standards in effect for those periods. The Company also elected the package of practical expedients permitted under the transition guidance within the new standard, which among other things, allowed them to carry forward the historical lease classification. Additionally, the Company elected the practical expedient related to land easements, which allows the carry forward of the accounting treatment for land easements on existing agreements. The total Right of Use (ROU) assets obtained in exchange for new operating lease liabilities upon adoption were $3.6 million.

An arrangement is determined to be a lease at inception based on whether the Company has the right to control the use of an identified asset. ROU assets represent the Company's right to use the underlying asset for the lease term and lease liabilities represent the Company's obligation to make lease payments arising from the lease. ROU assets and liabilities are recognized at the lease commencement date based on the present value of lease payments over the lease term, including payments at commencement that depend on an index or rate. Most leases in which the Company are the lessee do not have a readily determinable implicit rate, so an incremental borrowing rate, based on the information available at the lease commencement dates, utilized to determine the present value of lease payments. When a secured borrowing rate is not readily available, unsecured borrowing rates are adjusted for the effects of collateral to determine the incremental borrowing rate. Lease expense and lease income are recognized on a straight-line basis over the lease term for operating leases.

The Company has lease agreements with lease and non-lease components and have elected the practical expedient to combine lease and non-lease components for certain classes of leases, such as office buildings. For classes of leases in which lease and non-lease components are not combined, consideration is allocated between components based on the stand-alone prices.

The Company's lease agreements do not contain any material residual value guarantees, material restrictions or material covenants. There are no material lease transactions with related parties. Because risk is minimal, the Company does not take any significant actions to manage risk associated with the residual value of their leased assets.

The Company's lease agreements are primarily equipment and real property leases, including land and office facility leases. The Company's lease terms may include options to extend or terminate a lease when it is reasonably certain that those options will be exercised. The Company has elected an accounting policy that exempts leases with terms of one year or less from the recognition requirements of ASC 842.

The components of lease cost, included in *Other Operating* expense on the Company's *Statements of Consolidated Income*, are as follows:

	Year Ended December 31,	
(In millions)	2020	2019
Operating lease cost	$ 0.9	$ 0.9
Short-term lease cost	1.5	1.3
Total lease cost	$ 2.4	$ 2.2

Supplemental balance sheet information related to lease is as follows:

	December 31,	
(In millions, except lease term and discount rate)	2020	2019
Assets:		
Operating ROU assets [1]	$ 2.9	$ 2.8
Total leased assets	$ 2.9	$ 2.8
Liabilities:		
Current operating lease liability [2]	$ 0.9	$ 0.8
Non-current operating lease liability [3]	2.0	2.0
Total lease liabilities	$ 2.9	$ 2.8
Weighted-average remaining lease term (in years) - operating leases	5.2	6.1
Weighted-average discount rate - operating leases	2.68 %	3.57 %

(1) Reported within Other assets in the Consolidated Balance Sheet
(2) Reported within Current other liabilities in the Consolidated Balance Sheet
(3) Reported within Other liabilities in the Consolidated Balance Sheet

As of December 31, 2020, maturities of operating lease liabilities were as follows:

(In millions)		
2021	$	0.9
2022		0.9
2023		0.7
2024		0.2
2025		0.1
2026 and beyond		0.3
Total lease payments	$	3.1
Less: Interest		0.1
Present value of lease liabilities	$	3.0

Other information related to leases is as follows:

(In millions)		Year Ended December 31, 2020
Operating cash flows from operating leases included in the measurement of lease liabilities	$	0.8
ROU assets obtained in exchange for new operating lease liabilities [1]		—

[1] Includes the transition impact of adoption of ASU 2016-02 Leases as of January 1, 2019.

16. Subsequent Events

On February 4, 2021, the Company replaced its existing revolving credit facility with a new amended and restated credit facility. The size of the facility remains unchanged and remains guaranteed by SIGECO, Indiana Gas and VEDO. Based on the credit ratings as of February 4, 2021, the draw rate would have been LIBOR plus 1.250% under the facility. The credit facility contains provisions relating to the replacement of LIBOR.

In February 2021, an extreme and unprecedented winter weather event resulted in natural gas supply shortages and increased prices of natural gas in the United States, primarily due to prolonged freezing temperatures. The Company's utility subsidiaries have natural gas cost recovery mechanisms to recover the increased cost of natural gas.

SOUTHERN INDIANA GAS & ELECTRIC COMPANY FINANCIAL STATEMENTS

For the year ended December 31, 2020

Contents

DEFINITIONS

AFUDC	Allowance for funds used during construction
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
ASU	Accounting Standard Update
CECA	Clean Energy Cost Adjustment
COVID-19	Novel coronavirus disease 2019, and any mutations or variants thereof, and related global outbreak that was subsequently declared a pandemic by the World Health Organization
CODM	Chief Operating Decision Maker who is the Company's Chief Executive Officer
CSIA	Compliance and System Improvement Adjustment
DSMA	Demand Side Management Adjustment
ECA	Environmental Cost Adjustment
EEFC	Energy Efficiency Funding Component
EEFR	Energy Efficiency Funding Rider
EPA	Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulation Commission
IDEM	Indiana Department of Environmental Management
IURC	Indiana Utility Regulatory Commission
MISO	Midcontinent Independent System Operator
MW	megawatts
SERP	Supplemental Executive Retirement Plan
SRC	Sales Reconciliation Component
TCJA	Tax Cuts and Jobs Acts
TDSIC	Transmission, Distribution and Storage System Improvement Charge
VISCO	Vectren Infrastructure Services Corporation, a wholly - owned subsidiary of Vectren

INDEPENDENT AUDITORS’ REPORT

To the Director of Southern Indiana Gas and Electric Company:

We have audited the accompanying financial statements of Southern Indiana Gas and Electric Company (the "Company")(a wholly owned subsidiary of Vectren Utility Holdings, Inc.), which comprise the balance sheets as of December 31, 2020 and 2019, and the related statements of income, common shareholder’s equity, and cash flows for the years then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these 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 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 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 financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor’s judgment, including the assessment of the risks of material misstatement of the 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 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 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 financial statements referred to above present fairly, in all material respects, the financial position of Southern Indiana Gas and Electric Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP
Indianapolis, Indiana
March 10, 2021

FINANCIAL STATEMENTS

SOUTHERN INDIANA GAS & ELECTRIC COMPANY
BALANCE SHEETS
(*In millions*)

	December 31,			
		2020		2019
ASSETS				
Utility Plant				
Original cost	$	4,149.5	$	3,862.0
Less: accumulated depreciation & amortization		1,752.3		1,666.9
Net utility plant		**2,397.2**		**2,195.1**
Current Assets				
Cash & cash equivalents		2.7		3.7
Notes receivable from Vectren Utility Holdings		—		2.0
Accounts receivable - less reserves of $3.2 & $1.9, respectively		48.0		44.2
Accrued receivable from Vectren Utility Holdings		0.3		—
Accrued unbilled revenues - less reserves of $0.2 & -0-, respectively		24.6		24.4
Inventories		96.1		86.0
Recoverable fuel & natural gas costs		0.4		1.4
Prepayments & other current assets		7.9		9.3
Total current assets		**180.0**		**171.0**
Other investments		8.1		7.3
Nonutility plant - net		1.4		1.4
Goodwill		5.6		5.6
Regulatory assets		169.3		145.4
Other assets		45.1		45.9
TOTAL ASSETS	**$**	**2,806.7**	**$**	**2,571.7**

The accompanying notes are an integral part of these financial statements

SOUTHERN INDIANA GAS & ELECTRIC COMPANY
BALANCE SHEETS
(In millions)

	December 31, 2020	December 31, 2019
LIABILITIES & SHAREHOLDER'S EQUITY		
Common shareholder's equity		
Common stock (no par value)	$ 433.3	$ 433.3
Retained earnings	651.0	638.1
Total common shareholder's equity	**1,084.3**	**1,071.4**
Long-term debt payable to third parties	292.8	292.7
Long-term debt payable to Vectren Utility Holdings - net of current maturities	514.9	373.5
Total long-term debt	**807.7**	**666.2**
Commitments & Contingencies (Notes 6, 8-10)		
Current Liabilities		
Accounts payable	55.9	53.8
Payables to CenterPoint Energy	—	0.3
Payables to other Vectren companies	22.5	16.3
Refundable fuel & natural gas costs	0.3	1.2
Accrued liabilities	36.8	39.5
Short-term borrowings payable to Utility Holdings	72.2	—
Current maturities of long-term debt payable to Utility Holdings	54.6	114.5
Total current liabilities	**242.3**	**225.6**
Deferred Credits & Other Liabilities		
Deferred income taxes	266.9	213.9
Regulatory liabilities	259.7	260.5
Deferred credits & other liabilities	145.8	134.1
Total deferred credits & other liabilities	**672.4**	**608.5**
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	**$ 2,806.7**	**$ 2,571.7**

The accompanying notes are an integral part of these financial statements

SOUTHERN INDIANA GAS & ELECTRIC COMPANY
STATEMENTS OF INCOME
(In millions)

	Year Ended December 31, 2020		2019	
OPERATING REVENUES				
Electric utility	$	554.5	$	570.2
Gas utility		99.5		99.5
Total operating revenues		**654.0**		**669.7**
OPERATING EXPENSES				
Cost of fuel & purchased power		147.4		165.9
Cost of gas sold		28.0		33.6
Other operating		216.6		241.9
Depreciation & amortization		119.6		114.0
Taxes other than income taxes		19.7		19.2
Total operating expenses		**531.3**		**574.6**
OPERATING INCOME		**122.7**		**95.1**
Other income – net		11.1		4.1
Interest expense		32.3		33.7
INCOME BEFORE INCOME TAXES		**101.5**		**65.5**
Income taxes		19.6		9.0
NET INCOME	**$**	**81.9**	**$**	**56.5**

The accompanying notes are an integral part of these financial statements

SOUTHERN INDIANA GAS & ELECTRIC COMPANY
STATEMENTS OF CASH FLOWS
(*In millions*)

	Year Ended December 31, 2020	2019
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 81.9	$ 56.5
Adjustments to reconcile net income to cash from operating activities:		
Depreciation & amortization	119.6	114.0
Deferred income taxes & investment tax credits	43.0	19.8
Provision for uncollectible accounts	2.2	2.2
Expense portion of pension & postretirement benefit cost	5.1	6.4
Other non-cash items - net	2.0	(7.4)
Changes in working capital accounts:		
Accounts receivable & accrued unbilled revenue	(6.2)	3.1
Inventories	(10.1)	(16.1)
Recoverable/refundable fuel & natural gas costs	0.1	2.2
Prepayments & other current assets	3.5	5.1
Accounts payable	78.2	17.1
Accrued liabilities	(2.6)	(14.1)
Changes in noncurrent assets	(25.6)	(30.3)
Changes in noncurrent liabilities	(9.8)	(32.0)
Net cash from operating activities	**281.3**	**126.5**
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from:		
Long-term debt from Vectren Utility Holdings	196.0	40.0
Requirements for:		
Dividends to parent	(69.0)	—
Current maturities of long-term debt	(114.3)	—
Other - net	(0.2)	—
Net cash from financing activities	**12.5**	**40.0**
CASH FLOWS FROM INVESTING ACTIVITIES		
Proceeds from:		
Company-owned life insurance	—	9.6
Sale of investments	—	16.2
Requirements for:		
Capital expenditures, excluding AFUDC equity	(299.1)	(269.4)
Purchase of investments	—	(18.2)
Net change in short-term intercompany notes receivable	2.0	96.7
Other - net	2.3	—
Net cash from investing activities	**(294.8)**	**(165.1)**
Net change in cash & cash equivalents	(1.0)	1.4
Cash & cash equivalents at beginning of period	3.7	2.3
Cash & cash equivalents at end of period	$ 2.7	$ 3.7

The accompanying notes are an integral part of these financial statements

SOUTHERN INDIANA GAS & ELECTRIC COMPANY
STATEMENTS OF COMMON SHAREHOLDER'S EQUITY
(*In millions)*

	Common Stock	Retained Earnings	Total
Balance at January 1, 2019	**$ 433.3**	**$ 581.6**	**$ 1,014.9**
Net income		56.5	56.5
Common stock:			
Capital contribution from Utility Holdings	—		—
Dividends to Utility Holdings		—	—
Balance at December 31, 2019	**$ 433.3**	**$ 638.1**	**$ 1,071.4**
Net income		81.9	81.9
Common stock:			
Capital contribution from Utility Holdings	—		—
Dividends to Utility Holdings		(69.0)	(69.0)
Balance at December 31, 2020	**$ 433.3**	**$ 651.0**	**$ 1,084.3**

The accompanying notes are an integral part of these financial statements

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
NOTES TO THE FINANCIAL STATEMENTS

1. Organization and Nature of Operations

Southern Indiana Gas and Electric Company (the Company, or SIGECO), an Indiana corporation, provides energy delivery services to 149,289 electric customers and 114,125 gas customers located near Evansville in southwestern Indiana. Of these customers, 86,464 receive combined electric and gas distribution services. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. SIGECO is a direct, wholly owned subsidiary of Vectren Utility Holdings, Inc. (Utility Holdings or the Company's parent). The Company's parent is a direct, wholly owned subsidiary of Vectren Corporation (Vectren). Vectren, a wholly owned subsidiary of CenterPoint Energy, Inc. (collectively with its subsidiaries, CenterPoint Energy), is an energy holding company headquartered in Evansville, Indiana. During 2019 and 2020, SIGECO generally did business as Vectren Energy Delivery of Indiana, Inc., and during 2021 the Company began doing business as CenterPoint Energy Indiana South.

Merger with CenterPoint Energy
On February 1, 2019 (Merger Date), pursuant to the Merger Agreement, Vectren consummated the previously announced merger with CenterPoint Energy and was acquired for approximately $6 billion in cash (the Merger).

Pursuant to the Merger Agreement and immediately subsequent to the close of the Merger, Vectren cash settled all outstanding share-based awards issued prior to the Merger Date by Vectren to its employees. As a result, the Company recorded an incremental cost of $12 million in *Other operating expenses* on its *Consolidated Statements of Income* during the year ended December 31, 2019 for its share of allocated costs.

Subsequent to the close of the Merger, the Company recognized severance totaling $18 million to employees terminated in 2019, inclusive of change of control severance payments to executives of Vectren under existing agreements, and which is included in *Other operating expenses* on its *Consolidated Statements of Income* during the year ended December 31, 2019.

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 financial statements and related footnotes. Examples of transactions for which estimation techniques are used include valuing 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.

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 March 10, 2021, 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.

Accounts Receivables and Allowance for Credit Losses
Accounts receivable are recorded at the invoiced amount and do not bear interest. Management reviews historical write-offs, current available information, and reasonable and supportable forecasts to estimate and establish allowance for credit losses. Account balances are charged off against the allowance when management determines it is probable the receivable will not be recovered. See Note 5 for further information about regulatory deferrals of bad debt expense related to COVID-19.

Inventories
In most circumstances, the Company’s inventory components are recorded using an average cost method; however, natural gas in storage is recorded using the Last In – First Out (LIFO) method. Inventory 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
The IURC allows the Company 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 income – net* in the *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.

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 of Long-Lived Assets
The Company periodically evaluates long-lived assets, including property, plant and equipment, and specifically identifiable intangibles subject to amortization, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. Recoverability of long-lived assets is assessed by determining if a capital disallowance from a regulator is probable through monitoring the outcome of rate cases and other proceedings. No long-lived asset or intangible asset impairments were recorded in 2020, 2019 or 2018.

Goodwill
Goodwill recorded on the *Balance Sheets* results from the Company's 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 performs goodwill impairment tests at least annually and evaluates goodwill when events or changes in circumstances indicate that its carrying value may not be recoverable. The Company recognizes a goodwill impairment by the amount a reporting unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill within that reporting unit. The Company includes deferred tax assets and liabilities within its reporting unit's carrying value for the purposes of annual and interim impairment tests, regardless of whether the estimated fair value reflects the disposition of such assets and liabilities. No goodwill impairments were recorded in 2020, 2019, or 2018.

Regulation
Retail public utility operations are subject to regulation by the IURC. The Company is subject to FERC regulation as an electric public utility. 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 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 regulatory 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 the ability to recognize new regulatory assets associated with its regulated utility operations. The Company records pre-tax expense for (i) probable disallowances of capital investments and (ii) customer refund obligations and costs deferred in regulatory assets when recovery of such amounts is no longer considered probable. Given the current regulatory environment in its jurisdictions, the Company believes such accounting for regulatory assets and regulatory liabilities 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 collected in advance of expenditure as a *Regulatory liability* because the liability does not meet the threshold of an asset retirement obligation.

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 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.

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 *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, other than NPNS, is not material to these financial statements.

Income Taxes
On February 1, 2019, Vectren became a wholly-owned subsidiary of CenterPoint Energy and became included in CenterPoint Energy's consolidated federal income tax return. Vectren and certain subsidiaries are also included in various unitary or consolidated state income tax returns with CenterPoint Energy. In other state jurisdictions, Vectren and certain subsidiaries continue to file separate state tax returns. The Company calculates the provision for income taxes and income tax liabilities for each jurisdiction using a separate return method.

The Company uses the asset and liability method of accounting for deferred income taxes. Deferred income tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. A valuation allowance is established against deferred tax assets for which management believes realization is not considered to be more likely than not. The Company recognizes interest and penalties as a component of *income tax expense (benefit)*, as applicable, in their respective *Statements of Income*.

On December 22, 2017, President Trump signed into law comprehensive tax reform legislation informally called the Tax Cuts and Jobs Acts, or TCJA, which resulted in significant changes to federal tax laws effective January 1, 2018. See Note 6 for further discussion of the impacts of tax reform implementation.

To the extent certain excess deferred income taxes of the Company’s rate-regulated subsidiaries may be recoverable or payable through future rates, regulatory assets and liabilities have been recorded, respectively.

Investment tax credits are deferred and amortized to income over the approximate lives of the related property.

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 at least a net hourly position, meaning net purchases within that interval are recorded on the Company's *Statements of Income* in Utility natural gas, fuel and purchased power, and net sales within that interval are recorded on the Company's *Statements of Income* in 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.

Utility Receipts Taxes
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 $8.4 million in 2020 and $8.6 million in 2019. Expense associated with utility receipts taxes are recorded as a component of *Taxes other than income taxes*.

Reportable Segments
The Company's chief operating decision maker is the Chief Executive Officer of the Company. Beginning on February 1, 2019, upon close of the Merger, the Company aligned its reportable segments with CenterPoint Energy. During 2019, the measure of profitability used by management for all operations became operating income. During 2020, the Company's CODM views net income as the measure of profit or loss for the reportable segments rather than the previous measure of operating income. Prior period segment results have been recast to reflect management's profitability measure effective during 2020. Net income is the measure of profitability used by management for all operations. The Company segregates its regulated operations between a Natural Gas reportable segment and an Electric reportable segment. See Note 12 for further information.

Fair Value Measurements
Certain assets and liabilities are valued and disclosed at fair value. 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.

Other Significant Policies
Included elsewhere in these notes are significant accounting policies related to retirement plans and other postretirement benefits, intercompany allocations and income taxes (Note 6).

3. Revenue

In accordance with ASC 606, revenue is recognized when a customer obtains control of promised goods or services. The amount of revenue recognized reflects the consideration to which the Company expects to be entitled to receive in exchange for these goods or services.

The Company determines that disaggregating revenue into certain 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 12, include: Natural Gas and Electric.

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

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

(In millions)	Year Ended December 31, 2020	2019
Natural Gas		
Residential	$ 64.4	$ 64.7
Commercial	22.2	22.5
Industrial	12.9	12.0
Other	—	0.3
Total Natural Gas	$ 99.5	$ 99.5
Electric		
Residential	$ 209.1	$ 210.4
Commercial	144.3	148.1
Industrial	153.2	159.9
Other	47.9	51.8
Total Electric	$ 554.5	$ 570.2

Contract Balances
The Company does not have any material contract balances (right to consideration for services already provided or obligations to provide services in the future for consideration already received). Substantially all the Company's accounts receivable results from contracts with customers.

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

The Company adopted ASU 2016-13, Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments and all related amendments on January 1, 2020 using a modified retrospective method. ASU 2016-13 replaces the “incurred loss” model with a CECL model for financial assets measured at amortized cost and for certain off-balance sheet credit exposures. Adoption of this standard did not have a material impact on the Company's’ consolidated financial statements, and the Company had no material changes in its methodology to recognize losses on financial assets that fall under the scope of Topic 326.

4. Utility Plant & Depreciation

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

(In millions)	At and For the Year Ended December 31, 2020		2019	
	Original Cost	Depreciation Rates as a Percent of Original Cost	Original Cost	Depreciation Rates as a Percent of Original Cost
Electric utility plant	$ 3,249.1	3.3 %	$ 3,077.3	3.3 %
Gas utility plant	572.6	2.8 %	520.6	2.9 %
Common utility plant	71.5	3.6 %	70.8	3.5 %
Construction work in progress	179.5	—	117.7	—
Asset retirement obligations	76.8	—	75.6	—
Total original cost	**$ 4,149.5**		**$ 3,862.0**	

The Company 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. The Company's share of the cost of this unit at December 31, 2020, is $194.6 million with accumulated depreciation totaling $145.7 million. AGC and the Company share equally in the cost of operation and output of the unit. The Company's share of operating costs is included in *Other operating expenses* in the *Statements of Income.*

5. Regulatory Assets & Liabilities

<u>Regulatory Assets</u>
Regulatory assets consist of the following:

(In millions)	At December 31, 2020	2019
Future amounts recoverable from ratepayers related to:		
Asset retirement obligations & other	$ 40.0	$ 40.3
Net deferred income taxes	5.1	3.5
	45.1	43.8
Amounts deferred for future recovery related to:		
Cost recovery riders & other	47.8	31.7
	47.8	31.7
Amounts currently recovered through customer rates related to:		
Authorized trackers	67.7	61.1
Deferred coal costs	—	—
Unamortized debt issue costs, reacquisition premiums & hedging proceeds	8.7	8.8
	76.4	69.9
Total regulatory assets	**$ 169.3**	**$ 145.4**

Of the $76.4 million currently being recovered in rates charged to customers, no amounts are earning a return. The weighted average recovery period of regulatory assets currently being recovered in base rates, which totals $8.7 million, is 21 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 future recovery is probable.

Regulatory assets for asset retirement obligations are a result of costs incurred for expected retirement activity for the Company's ash ponds beyond what has been recovered in rates. The Company believes the recovery of these assets are probable as the costs are currently being recovered in rates. See Note 10 for further information.

Regulatory Liabilities
At December 31, 2020 and 2019, the Company had regulatory liabilities $259.7 million and $260.5 million, respectively, of which $75.9 million and $68.7 million related to cost of removal obligations and $183.7 million and $191.5 million related to deferred taxes, at December 31, 2020 and 2019, 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 as ordered by the IURC.

COVID-19 Regulatory Matters
Governors, public utility commissions and other authorities in Indiana have issued a number of different orders related to the COVID-19 pandemic, including orders addressing customer non-payment and disconnection. The IURC authorized utilities to employ deferred accounting authority for certain COVID-19 related costs which ensure the safety and health of customers, employees, and contractors, that would not have been incurred in the normal course of business. Additionally, the IURC issued orders to record a regulatory asset for incremental bad debt expenses related to COVID-19, including costs associated with the suspension of disconnections and payment plans. The Company has recorded incremental uncollectible receivables to the associated regulatory asset of $1.1 million, as of December 31, 2020.

6. Transactions with Other Vectren Companies & Affiliates

Vectren Infrastructure Services Corporation (VISCO)
On April 9, 2020, Vectren closed on a transaction to sell its Infrastructure Services businesses which provided underground pipeline construction and repair services. VISCO's customers included the Company's utilities and fees incurred by the Company totaled:

(In millions)	2020(1)	2019
Pipeline construction and repair services(2)	$ 5.8	$ 19.7

(1) Represents charges for the period, January 1, 2020 until the closing of the sale of VISCO.

(2) Amounts owed to VISCO are included in Payable to other Vectren companies until the closing of the sale of VISCO.

Support Services and Purchases
Affiliates of CenterPoint Energy and Vectren provide corporate and general and administrative services to the Company and allocate certain costs to the Company. These services are billed to the Company at actual cost, either directly or as allocation using various allocators, including number of employees, number of customers and/or the level of payroll, revenue contribution and capital expenditures. Affiliates of CenterPoint Energy provide other miscellaneous services, including geographic services and other management support. These services are billed at actual cost, and the charges are not necessarily indicative of what would have been incurred had CenterPoint Energy's subsidiaries not been affiliates. Amounts owed for support services and purchases at December 31, 2020 and 2019 are included in *Payables to other Vectren companies* and *Payables to CenterPoint Energy.*

Additionally, CenterPoint Energy, through its energy service subsidiary divested in June 2020, sold natural gas to Electric for use in electric generation activities. Contracts for natural gas were executed in a competitive bidding process and are reflective of what would have been incurred had CenterPoint Energy not been an affiliate.

(In millions)	2020(1)	2019
Affiliate natural gas expense (1)	$ 0.7	$ 1.1
Corporate allocations (2)	$ 54.5	$ 78.5

(1) Amounts charged for natural gas are included primarily in *Cost of fuel and purchased power*.

(2) The allocated costs in 2019 include $17.8 million of severance and $12.2 million of stock-based compensation as a result of the
Merger with CenterPoint Energy. The allocated costs in 2019 and 2020 also include allocations from CenterPoint Energy cororporate service charges. Amounts charged for these services are reflected primarily in *Other Operating*.

<u>Retirement Plans & Other Postretirement Benefits</u>
At December 31, 2020, Vectren maintains three closed qualified defined benefit pension plans (Vectren Corporation Non-Bargaining Retirement Plan, The Indiana Gas Company, Inc. Bargaining Unit Retirement Plan, Pension Plan for Hourly Employees of Southern Indiana Gas and Electric Company), a nonqualified supplemental executive retirement plan (SERP), and a postretirement benefit plan. The defined benefit pension plans and postretirement benefit plan, which cover the Company's 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. Current and former employees of Vectren and its subsidiaries, which include the Company, comprise the vast majority of the participants and retirees covered by these plans.

Vectren satisfies the future funding requirements for funded plans and the payment of benefits for unfunded plans from general corporate assets and, as necessary, relies on the Company to support the funding of these obligations. However, the Company has no contractual funding obligation to the plans. The Company did not make a contribution in 2020 and 2019 to Vectren for the defined benefit and pension plans. The Company contributed $1.5 million in 2020 and $7.7 million in 2019 to Vectren for SERP and post retirement benefit plans. The combined funded status of Vectren's defined benefit pension plans was approximately 92 percent and 90 percent at December 31, 2020 and 2019, respectively.

Vectren allocates retirement plan and other postretirement benefit plan periodic cost calculated pursuant to US GAAP to its subsidiaries, which is also how the Company recovers retirement plan periodic costs through base rates. Periodic cost is charged to the Company following a labor cost allocation methodology and results in retirement costs being allocated to both operating expense and capital projects. Costs totaling $4.4 million and $7.3 million were charged to the Company in years ended December 31, 2020 and 2019, respectively.

Any difference between the Company's funding requirements to Vectren and allocated periodic costs is recognized by the Company as an intercompany asset or liability. The allocation methodology to determine the intercompany funding requirements from the subsidiaries to Vectren is consistent with FASB guidance related to "multiemployer" benefit accounting. Neither plan assets nor plan obligations as calculated pursuant to GAAP by Vectren are allocated to individual subsidiaries.

As of December 31, 2020 and 2019, the Company had $21.4 million and $24.6 million, respectively, included in *Other Assets* representing defined benefit pension funding by the Company to Vectren that is yet to be reflected in costs. As of December 31, 2020 and 2019, the Company had $17.0 million and $17.7 million, respectively, included in *Deferred credits & other liabilities* representing costs related to other postretirement benefits charged to the Company that is yet to be funded to Vectren. The Company's labor allocation methodology is used to compute the Company's funding of the defined benefit retirement and other postretirement plans to Vectren, which is consistent with the regulatory ratemaking processes of the Company.

<u>Share-Based Incentive Plans and Deferred Compensation Plans</u>
The Company does not have share-based compensation plans separate from Vectren or CenterPoint Energy. The Company recognizes its allocated portion of costs related to share-based incentive plans and deferred compensation plans in accordance with FASB guidance and to the extent these awards are expected to be settled in cash, that liability is pushed down to SIGECO. As of December 31, 2020 and 2019, $2.5 million and $2.1 million, respectively, is included in *Accrued liabilities* and *Deferred credits & other liabilities* and represents deferred compensation obligations that are yet to be funded in the plan. Subsequent to the February 1, 2019 completion of the Merger, and pursuant to the Merger Agreement, all Vectren's share-based awards have been settled and a majority of its deferred compensation liabilities have been settled.

<u>Cash Management Arrangements</u>
The Company participates in the centralized cash management program with affiliates of Vectren. See Note 7 for further information regarding intercompany borrowing arrangements.

<u>Guarantees of the Company's Parent</u>
The three operating utility companies of the Company's parent, SIGECO, Indiana Gas Company, Inc. (Indiana Gas) and Vectren Energy Delivery of Ohio, Inc. (VEDO) are guarantors of its $400 million commercial paper borrowing arrangements and its $432

million in unsecured senior notes and term loans outstanding at December 31, 2020. The majority of the unsecured senior notes and term loans outstanding of the Company's parent are allocated to the operating utility companies. The guarantees are full and unconditional and joint and several, and the Company's parent has no subsidiaries other than the subsidiary guarantors.

In connection with the Merger, the Company's parent made offers to prepay certain outstanding guaranteed senior notes as required pursuant to certain purchase agreements. In turn, the Company's parent borrowed $568 million to make the prepayment at the same interest rate and term as the notes being prepaid. The CenterPoint Energy notes are not guaranteed by the Company or the other operating utility companies of the Company's parent.

Income Taxes

The Company does not file federal or state income tax returns separate from those filed by Vectren or CenterPoint Energy. As of February 2, 2019, Vectren is included in CenterPoint Energy's consolidated U.S. federal income tax return. Vectren and/or certain of its subsidiaries file income tax returns in various states. Pursuant to a tax sharing agreement and for financial reporting purposes, Vectren subsidiaries record income taxes on a separate company basis. The Company's allocated share of tax effects resulting from it being a part of Vectren's consolidated tax group are recorded at the Company's parent level. Current taxes payable/receivable are settled with Vectren in cash quarterly and after filing the consolidated federal and state income tax returns.

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 recognizes regulatory liabilities 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 *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.

The Company's gas and electric utilities currently recover corporate income tax expense in approved rates charged to customers. The IURC issued an order which initiated a proceeding to investigate the impact of the Tax Cuts and Jobs Act (TCJA) on utility companies and customers within the state. In addition, the IURC ordered the Company to establish regulatory liabilities to record all estimated impacts of tax reform starting January 1, 2018. As of December 31, 2020 and 2019, the Company has $183.7 million and $191.5 million, respectively, in liabilities associated with excess deferred income taxes.

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 electric customers and in January 2019 for the Company’s gas customers.

The components of income tax expense/(benefit) and amortization of investment tax credits follow:

(In millions)	Year Ended December 31, 2020	2019
Current:		
Federal	$ (18.7)	$ (1.7)
State	(4.7)	(1.4)
Total current tax expense/(benefit)	**(23.4)**	**(3.1)**
Deferred:		
Federal	34.2	9.2
State	9.4	4.2
Total deferred tax expense	**43.6**	**13.4**
Amortization of investment tax credit deferred / (amortized)	(0.6)	(1.3)
Total income tax expense	**$ 19.6**	**$ 9.0**

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

	Year Ended December 31, 2020	2019
Statutory rate	21.0 %	21.0 %
Federal tax law change impacts	(4.2)	(6.5)
State & local taxes, net of federal benefit	4.4	5.4
Research & development tax credits	0.3	(4.4)
All other - net	(2.2)	(1.8)
Effective tax rate	**19.3 %**	**13.7 %**

Significant components of the net deferred tax liability follow:

(In millions)	At December 31, 2020	2019
Noncurrent deferred tax assets:		
Regulatory liabilities settled through future rates	$ 43.2	49.4
Total deferred tax assets:	43.2	49.4
Noncurrent deferred tax assets:		
Depreciation & cost recovery timing differences	$ 283.7	$ 244.0
Regulatory assets recoverable through future rates	6.8	5.3
Employee benefit obligations	2.2	1.7
Deferred fuel costs	9.3	5.7
Other – net	8.1	6.6
Total deferred tax liabilities	**$ 310.1**	**$ 263.3**
Net deferred tax liability	**$ 266.9**	**$ 213.9**

At December 31, 2020 and 2019, investment tax credits totaling $2.8 million and $3.3 million, respectively, are included in *Deferred credits & other liabilities*.

Uncertain Tax Positions

Unrecognized tax benefits for all periods presented were not material to the Company. The net liability on the *Balance Sheet* for unrecognized tax benefits inclusive of interest and penalties totaled $0.3 million and $0.3 million at December 31, 2020 and 2019, respectively.

Vectren and certain of its subsidiaries file income tax returns in the U.S. federal jurisdiction and various states. The Internal Revenue Service (IRS) has concluded examinations of Vectren's U.S. federal income tax return for tax year December 31, 2016 with no adjustments. The State of Indiana, Vectren's primary state tax jurisdiction has concluded examinations of Vectren's consolidated state income tax returns for tax years through 2017 with no adjustments. The statutes of limitations for assessment of federal income tax and Indiana income tax have expired with respect to tax years through 2017 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 expired in 2020. The statutes of limitations for assessment of the 2013 and 2014 tax years related to the amended Indiana income tax returns expired in 2020.

7. Borrowing Arrangements & Other Financing Transactions

Long-Term Debt
Long-term senior unsecured obligations and first mortgage bonds outstanding follow:

	At December 31,			
(In millions)	2020		2019	
Fixed Rate Senior Unsecured Notes Payable to Utility Holdings:				
2020, 6.28%		—		99.5
2021, 4.67%		54.6		54.6
2023, 3.72%		24.8		24.8
2028, 3.20%		26.9		26.9
2032, 3.26%		74.6		74.6
2035, 6.10%		25.3		25.3
2035, 3.90%		16.6		16.6
2043, 4.25%		47.7		47.7
2045, 4.36%		16.6		16.6
2047, 3.93%		29.8		29.8
2055, 4.51%		16.6		16.6
2049, 3.42%		80.0		40.0
2050, 1.21%		100.0		—
2030, 1.72%.		56.0		—
Variable Rate Term Loans				
2020, current adjustable rate, 2.5125%		—		15.0
Total long-term debt payable to Utility Holdings		**569.5**		**488.0**
Current maturities		(54.6)		(114.5)
Total long-term debt payable to Utility Holdings	**$**	**514.9**	**$**	**373.5**
First Mortgage Bonds Payable to Third Parties:				
2022, 2013 Series C, current adjustable rate .88%, tax-exempt	$	4.6	$	4.6
2024, 2013 Series D, current adjustable rate .88%, tax-exempt		22.5		22.5
2025, 2014 Series B, current adjustable rate .88%, tax-exempt		41.3		41.3
2029, 1999 Series, 6.72%		80.0		80.0
2037, 2013 Series E, current adjustable rate .88%, tax-exempt		22.0		22.0
2038, 2013 Series A, current adjustable rate .88%, tax-exempt		22.2		22.2
2043, 2013 Series B, current adjustable rate .88%, tax-exempt		39.6		39.6
2044, 2014 Series A, 4.00%, tax exempt		22.3		22.3
2055, 2015 Series Mt. Vernon, .875%, tax-exempt		23.0		23.0
2055, 2015 Series Warrick County, .875%, tax-exempt		15.2		15.2
Total first mortgage bonds payable to third parties		**292.7**		**292.7**
Unamortized debt premium, discount & other - net		0.1		—
Total long-term debt payable to third parties - net	**$**	**292.8**	**$**	**292.7**

Term Loan
On July 30, 2018, the Company's parent 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 depending on the Company's parent credit rating. In addition, the term loan contains a provision that should the Company's parent 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 the Company's parent wholly-owned operating companies, SIGECO, Indiana Gas, and VEDO. The Company received approximately $15 million of these proceeds. The Company's parent term loan was repaid on September 30, 2020.

<u>SIGECO Variable Rate Tax-Exempt Bonds</u>
On March 1, 2018 and May 1, 2018, the Company executed first and second amendments to a Bond Purchase and Covenants Agreement originally signed in September 2017. These amendments provided the Company 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.

In September 2020, the Company completed the remarketing of two series of tax-exempt debt of approximately $38 million, comprised of: (i) $23 million aggregate principal amount of Environmental Improvement Revenue Bonds, Series 2015, issued by the City of Mount Vernon, Indiana, and (ii) $15 million aggregate principal amount of Environmental Improvement Revenue Bonds, Series 2015, issued by Warrick County, Indiana, that, in each case, were originally issued on September 9, 2015. Both series of revenue bonds originally had an initial term interest rate of 2.375 percent. After the remarketing, each series of revenue bonds have a new term interest rate of 0.875 percent that is fixed through August 31, 2023. Each series of revenue bonds have a final maturity date of September 1, 2055, subject to prior redemption.

The Company 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 the Company's credit rating, among others, may result in an actual interest rate above or below the anticipated fixed rate. Regulatory orders require the Company 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, 2019, certain series of SIGECO bonds, aggregating $185.7 million were subject to mandatory tenders prior to the bonds' final maturities. In 2020, $38.2 million was tendered and remarketed and $147.5 million will be tendered in 2023.

Future Long-Term Debt Sinking Fund Requirements and Maturities
The annual sinking fund requirement of the Company'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. The Company met the 2020 sinking fund requirement by this means and expects to also meet this requirement in 2021 in this manner. Accordingly, the sinking fund requirement is excluded from *Current liabilities* in the *Balance Sheets*. At December 31, 2020, $2.1 billion of utility plant remained unfunded under the Company's Mortgage Indenture. The Company's gross utility plant balance subject to the Mortgage Indenture approximated $4.1 billion at December 31, 2020.

Maturities of third party long-term debt during the five years following 2020 (in millions) are $-0- in 2021, $4.6 in 2022, $-0- in 2023, $22.5 in 2024, $41.3 in 2025, and $224.3 thereafter. Maturities of affiliated long-term debt during the five years following 2020 (in millions) are $54.6 in 2021, $-0- in 2022, $24.8 in 2023, $-0- in 2024, $56.0 in 2025, and $434.1 thereafter.

Covenants
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. As of December 31, 2020, the Company was in compliance with all financial debt covenants.

8. Commitments & Contingencies

Purchase Commitments
The Company has firm commitments to purchase natural gas for up to a five year term, with the majority of these commitments being a term of two years or less. The Company also has other firm and non-firm commitments to purchase coal, electricity, as well as certain transportation and storage rights, some of which are firm commitments under five and twenty year arrangements. Costs arising from these commitments, while significant, are pass-through costs, generally collected dollar-for-dollar from retail customers through regulator-approved cost recovery mechanisms.

The Company's minimum purchase obligations for these commitments, which have various quantity requirements and duration are $96 million in 2021, $93 million in 2022, $78 million in 2023, $45 million in 2024, $72 million in 2025, and $189 million thereafter.

Letters of Credit
The Company, from time to time, issues letters of credit to support operations. At December 31, 2020, letters of credit outstanding total $-0- million.

Legal and 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.

9. Regulatory Matters

COVID-19 Regulatory Matters
Governors, public utility commissions and other authorities in Indiana and Ohio have issued a number of different orders related to the COVID-19 pandemic, including orders addressing customer non-payment and disconnection. While certain jurisdictions are subject to mandatory stay-at-home and similar orders, essential businesses and activities are exempted from these orders, including utility operations and maintenance. Accordingly, the Company's crews continue to provide essential service by responding to calls, completing work orders and undertaking other critical work. To protect its customers and employees, the Company has implemented COVID-19 safety precautions. Although the disconnect moratoriums have expired, the Company continues to support those customers who may need payment assistance, arrangements or extensions. The Company continue to monitor developments in this area and adjust our response as guidelines and circumstances may require. Additionally, while the Company has not experienced delays to date due to COVID-19 with respect to its regulatory proceedings, it could experience significant delays in scheduling proceedings or hearings and in obtaining orders from regulatory agencies. See Note 5 for further information.

SIGECO Base Rate Case
On October 30, 2020, and as subsequently amended, the Company filed its base rate case with the IURC seeking approval for a revenue increase of approximately $29 million. This rate case filing is required under Indiana TDSIC statutory requirements before the completion of the Company's capital expenditure program, approved in 2014 for investments starting in 2014 through 2020. The revenue increase is based upon a requested ROE of 10.15% and an overall after-tax rate of return of 5.99% on total rate base of approximately $469 million. The Company has utilized a projected test year, reflecting its 2021 budget as the basis for the revenue increase requested, and proposes to implement rates in two phases. The first phase of rate implementation will occur as of the date of an order in this proceeding, expected in September 2021, and the second phase of rate implementation will occur at the completion of the test year, as of December 31, 2021. Under Indiana statutory requirements, the IURC has a minimum 300 days and maximum of 360 days from the date of the filing of the Company's case- in-chief to issue an order.

Electric Generation Project

The Company must either (i) make substantial investments in its existing generation resources to comply with environmental regulations or (ii) replace its existing generation with new resources. Indiana requires each electric utility to perform and submit an IRP every three years (unless extended) to the IURC that uses economic modeling to consider the costs and risks associated with available resource options to provide reliable electric service for the next 20-year period. On February 20, 2018, the Company filed a petition seeking authorization from the IURC to construct a new 700-850 MW natural gas combined cycle generating facility to replace the baseload capacity of its existing generation fleet at an approximate cost of $900 million, which included the cost of a new natural gas pipeline to serve the plant.

As a part of this same proceeding, the Company also sought recovery under Indiana Senate Bill 251 of costs to be incurred for environmental investments to be made at its F.B. Culley generating plant to comply with ELG and CCR rules. The F.B. Culley investments, estimated to be approximately $95 million, began 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 customers. Under Indiana Senate Bill 251, the Company sought authority to recover 80% of the approved costs, including a return, using a tracking mechanism, with the remaining 20% of the costs deferred for recovery in the Company's next base rate proceeding.

On April 24, 2019, the IURC issued an order approving the environmental investments proposed for the F.B. Culley generating facility, along with recovery of prior pollution control investments made in 2014. The order denied the proposed gas combined cycle generating facility. The Company has conducted a new IRP, which was submitted to the IURC in June 2020, to identify an appropriate generation resource portfolio that includes the replacement of 730 MW of coal-fired generation facilities with a significant buildout of renewables supported by dispatchable natural gas combustion turbines.

A.B. Brown Ash Pond Remediation

On August 14, 2019, the Company filed a petition with the IURC, seeking approval, as a federally mandated project, for the recovery of costs associated with the clean closure of the A.B. Brown ash pond pursuant to Indiana Senate Bill 251. This project, expected to last approximately 14 years, would result in the full excavation and recycling of the ponded ash through agreements with a beneficial reuse entity, totaling approximately $160 million. Under Indiana Senate Bill 251, the Company seeks authority to recover via a tracking mechanism 80% of the approved costs, with a return on eligible capital investments needed to allow for the extraction of the ponded ash, with the remaining 20% of the costs deferred for recovery in the Company's next base rate proceeding. On December 19, 2019 and subsequently on January 10, 2020, the Company filed a settlement agreement with the intervening parties whereby the costs would be recovered as requested, with an additional commitment by the Company to offset the federally mandated costs by at least $25 million, representing a combination of total cash proceeds received from the ash reuser and total insurance proceeds to be received from the Company's insurers under confidential settlement agreements of litigation filed against the insurers. On May 13, 2020, the IURC approved the settlement agreement in full. On October 28, 2020, the IURC approved the Company's ECA proceeding, which included the initiation of recovery of the federally mandated project costs.

Rate Change Applications

The Company is routinely involved in rate change applications before state regulatory authorities. Those applications include general rate cases, where the entire cost of service of the utility is assessed and reset. In addition, the Company is periodically involved in proceedings to adjust its capital tracking mechanisms in Indiana (CSIA for gas and TDSIC, ECA and CECA for Electric) and Ohio (DRR), its decoupling mechanism in Indiana (SRC for gas), and its energy efficiency cost trackers in Indiana (EEFC for gas and DSMA for electric).

The table below reflects significant applications pending or completed during 2020 and to date in 2021 for the Company.

Mechanism	**Annual Increase (Decrease) (1) (in millions)**	Filing Date	Effective Date	Approval Date	**Additional Information**
			Indiana South - Gas (IURC)		
CSIA	1	April 2020	July 2020	July 2020	Requested an increase of $13 million to rate base, which reflects a $1 million annual increase in current revenues. 80% of revenue requirement is included in requested rate increase and 20% is deferred until the next rate case. The mechanism also includes refunds associated with the TCJA, resulting in no change to the previous credit provided, and a change in the total (over)/under- recovery variance of $1 million annually.
CSIA	2	October 2020	January 2021	January 2021	Requested an increase of $13 million to rate base, which reflects a $2 million annual increase in current revenues. 80% of revenue requirement is included in requested rate increase and 20% is deferred until the next rate case. The mechanism also includes refunds associated with the TCJA, resulting in no change to the previous credit provided, and a change in the total (over)/under-recovery variance of $(1) million annually.
Rate Case (1)	29	October 2020	September 2021	TBD	See discussion above under SIGECO Base Rate Case.
			Indiana Electric (IURC)		
TDSIC	4	February 2020	May 2020	May 2020	Requested an increase of $34 million to rate base, which reflects a $4 million annual increase in current revenues. 80% of revenue requirement is included in requested rate increase and 20% is deferred until next rate case. The mechanism also includes a change in (over)/under-recovery variance of $2 million annually.
ECA	10	May 2020	August 2020	October 2020	Requested an increase of $49 million to rate base, which reflects a $10 million annual increase in current revenues. 80% of the revenue requirement is included in requested rate increase and 20% is deferred until next rate case. The mechanism also includes a change in (over)/under-recovery variance of $4 million annually.
TDSIC	3	August 2020	November 2020	November 2020	Requested an increase of $36 million to rate base, which reflects a $3 million annual increase in current revenues. 80% of the revenue requirement is included in requested rate increase and 20% is deferred until next rate case. The mechanism also includes a change in (over) under-recovery variance of $(1) million annually.

Mechanism	**Annual Increase (Decrease) (1) (in millions)**	Filing Date	Effective Date	Approval Date	**Additional Information**
TDSIC(1)	3	February 2021	May 2021	TBD	Requested an increase of $28 million to rate base, which reflects a $3 million annual increase in current revenues. 80% of the revenue requirement is included in requested rate increase and 20% is deferred until next rate case. The mechanism also included a change in (over) under-recovery variance of less than $1 million.
CECA(1)	8	February 2021	TBD	TBD	Reflects an $8 million annual increase in current revenues through a non-traditional rate making approach related to a 50 MW universal solar array placed in service in January 2021.

(1) Represents proposed increases (decreases) when effective date and/or approval date is not yet determined. Approved rates could differ materially from proposed rates.

10. Environmental and Sustainability Matters

Coal Ash Waste Disposal, Ash Ponds and Water

Coal Combustion Residuals Rule
In April 2015, the EPA finalized its CCR Rule, which regulates ash as non-hazardous material under the Resource Conservation and Recovery Act of 1976 (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.

The Company has three ash ponds, two at the F.B. Culley facility (Culley East and Culley West) and one at the A.B. Brown facility. Under the existing CCR Rule, the Company is required to perform integrity assessments, including ground water monitoring, at its F.B. Culley and A.B. Brown generating stations. The ground water studies are necessary 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. The Company's Warrick generating unit is not included in the scope of the CCR Rule as this unit has historically been part of a larger generating station that predominantly serves an adjacent industrial facility. In March 2018, the Company began posting ground water data monitoring reports annually to its public website in accordance with the requirements of the CCR Rule. This data preliminarily indicates potential groundwater impacts very close to the Company's ash impoundments, and further analysis is ongoing. The CCR Rule required companies to complete location restriction determinations by October 18, 2018. The company completed its evaluation and determined that one F.B. Culley pond (Culley East) and the A.B. Brown pond fail the aquifer placement location restriction. As a result of this failure, the Company is required to cease disposal of new ash in the ponds and commence closure of the ponds by April 11, 2021. The Company plans to seek extensions available under the CCR Rule that would allow the Company to continue to use the ponds through October 15, 2023. The inability to take these extensions may result in increased and potentially significant operational costs in connection with the accelerated implementation of an alternative ash disposal system or adversely impact the Company's future operations. Failure to comply with these requirements could also result in an enforcement proceeding including the imposition of fines and penalties. On April 24, 2019, the Company received an order from the IURC approving recovery in rates of costs associated with the closure of the Culley West pond, which completed closure activities under its approved closure plan in December 2020.

In March 2019, the Company entered into agreements with third parties for the excavation and beneficial reuse of the ash at the A.B. Brown ash pond. On August 14, 2019, the Company filed its petition with the IURC for recovery of costs associated with the closure the A.B. Brown ash pond, which would include costs associated with the excavation and recycling of the ponded ash.

This petition was subsequently approved by the IURC on May 13, 2020. On October 28, 2020, the IURC approved Indiana Electric’s ECA proceeding, which included the initiation of recovery of the federally mandated project costs. In July 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, and has since reached confidential settlement agreements with its insurers. The proceeds of these settlements will offset costs that have been and will be incurred to close the ponds. The Company continues to refine site specific estimates of closure costs for its 10 acre Culley East pond.

As of December 31, 2020, the Company has recorded an approximate $74 million ARO, which represents the discounted value of future cash flow estimates to close the ponds at A.B. Brown and F.B. Culley. This estimate is subject to change due to the contractual arrangements; continued assessments of the ash, closure methods, and the timing of closure; implications of the Company's generation transition plan; changing environmental regulations; and proceeds received from the settlements in the aforementioned insurance proceeding. In addition to these removal costs, the Company also anticipates equipment purchases of between $60 million and $80 million to complete the A.B. Brown closure project.

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 the Company's water discharge permits, in 2017 the IDEM issued final renewals for the 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, which have been completed, 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 U.S. President’s 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, the EPA finalized a rule postponing certain interim compliance dates by two years, but did not postpone final compliance deadline of December 31, 2023. On April 12, 2019, the U.S. Court of Appeals for the Fifth Circuit vacated and remanded portions of the ELG that selected impoundment as the best available technology for legacy wastewater and leachate. On October 13, 2020, the EPA finalized revisions to the ELG rule, which established a two-year extension of the compliance deadline for the prohibition of wet sluicing of bottom ash. However, the ELG rule did not establish alternative deadlines for the prohibition of wet sluicing of fly ash, and the most recent revision to the CCR rule confirmed that ash ponds must commence closure no later than October 2023. As a result, CenterPoint Energy does not currently anticipate any changes to its current compliance plans based upon this most recent ELG update.

Cooling Water Intake Structures
Section 316 of the federal Clean Water Act requires steam electric generating facilities use “best technology available” to minimize adverse environmental impacts on a body of water. In May 2014 EPA finalized a regulation requiring installation of best technology available (BTA) to mitigate impingement entrainment of aquatic species in cooling water intake structures. The Company is currently completing the required ecological studies and anticipates timely compliance in 2021-2022.

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

Clean Power Plan and Affordable Clean Energy (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. The final rule was published in the Federal Register on October 23, 2015, and that action was immediately followed by litigation ultimately resulting in the U.S. Supreme Court staying implementation of the rule.

In August 2018, the EPA proposed a CPP replacement rule, the ACE Rule, which was finalized in July 2019 and required states to implement a program of energy efficiency improvement targets for individual coal-fired electric generating units. On January

19, 2021, the ACE Rule was struck down by the U.S. District Court of Appeals for the D.C. Circuit. We are currently unable to predict whether the Biden Administration will continue its defense of the CPP or ACE rules, or what a new replacement rule would look like.

Impact of Legislative Actions & Other Initiatives
At this time, compliance costs and other effects associated with reductions in greenhouse gases (GHG) emissions or obtaining renewable energy sources remain uncertain. Moreover, the Biden Administration has moved to reenter the Paris Climate Agreement. While the requirements of a new GHG replacement rule remain uncertain, the Company will continue to monitor regulatory and legislative activity regarding GHG emission standards that may affect its electric generating units.

Manufactured Gas Plants
The Company and its predecessors operated manufactured gas plants in the past. The Company has accrued estimated costs for investigation, remediation, and ground water monitoring that it expects to incur to fulfill its respective obligations using assumptions based on actual costs incurred, the timing of expected future payments and inflation factors, among others. While the Company has recorded all costs which it presently is obligated 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 potentially responsible parties (PRP) or insurance recovery.

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. As of December 31, 2020 and December 31, 2019, approximately $2.3 million and $2.8 million, respectively of accrued, but not yet spent, costs are included in Other Liabilities related to these sites.

11. Fair Value Measurements

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

	At December 31,			
	2020		2019	
(In millions)	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt payable to third parties	$ 292.8	$ 324.4	$ 292.7	$ 318.1
Long-term debt payable to Utility Holdings	569.5	653.9	488.0	507.3
Short-term notes receivable from Utility Holdings	—	—	2.0	2.0
Natural gas purchase instrument liabilities (1)	2.0	2.0	3.4	3.4
Interest rate swap liabilities (2) (3)	20.0	20.0	9.8	9.8
Cash & cash equivalents	2.7	2.7	3.7	3.7

(1) Presented in "Accrued liabilities" and "Deferred credits & other liabilities" on the Balance Sheets.

(2) Presented in "Deferred credits & other liabilities" on the Balance Sheets.

(3) Presented in "Deferred credits & other liabilities" on the *Consolidated Balance Sheets.* The interest rate swaps contain provisions that require the Company to maintain an investment grade credit rating on its long-term unsecured unsubordinated debt from S&P and Moody's. If the Company's debt were to fall below investment grade, it would be in violation of these provisions, and the counterparties to the interest rate swaps could request immediate payment. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position on December 31, 2020, is approximately $20 million for which the Company has posted collateral of $6.5 million in the normal course of business. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2020, the Company would be required to post an additional $3.5 million of collateral to its counterparties. The maximum collateral required if further escalating collateral is triggered would equal the net liability position.

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 entered into two 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 gas cost recovery mechanism.

The Company executed forward starting interest rate swaps during 2017 providing that on January 1, 2020, the Company will begin hedging the 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.

12. Segment Reporting

The Company segregates its operations into two reportable segments: 1) Natural Gas and 2) Electric. As of January 1, 2020, the Company's CODM views net income as the measure of profit or loss for the reportable segments rather than the previous measure of operating income. Certain prior year amounts have been reclassified to conform to the current year presentation. See Note 2 for further information.

As of December 31, 2020, reportable segments are as follows:

- The Natural Gas segment provides natural gas distribution and transportation services to primarily southwestern Indiana.
- The Electric segment provides electric generation, transmission and distribution services primarily to southwestern Indiana, and includes the Company's power generating and wholesale power operations.

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

	Year Ended December 31,	
(In millions)	2020	2019
Revenues		
Natural Gas	$ 99.5	$ 99.5
Electric	554.5	570.2
Total revenues	**$ 654.0**	**$ 669.7**
Profitability Measure - Net Income		
Natural Gas	$ 8.8	$ (1.5)
Electric	73.1	58.0
Total net income	**$ 81.9**	**$ 56.5**
Depreciation & Amortization		
Natural Gas	$ 15.7	$ 14.3
Electric	103.9	99.7
Total depreciation & amortization	**$ 119.6**	**$ 114.0**
Capital Expenditures		
Natural Gas	$ 47.6	$ 49.3
Electric	260.1	204.1
Non-cash costs & changes in accruals	(8.6)	16.0
Total capital expenditures	**$ 299.1**	**$ 269.4**

	At December 31,	
(In millions)	2020	2019
Assets		
Natural Gas	$ 551.9	$ 518.7
Electric	2,254.8	2,053.0
Total assets	**$ 2,806.7**	**$ 2,571.7**

13. Additional Balance Sheet & Operational Information

Inventories in the *Balance Sheets* consist of the following:

(In millions)	At December 31, 2020	2019
Materials & supplies	$ 33.7	$ 33.1
Fuel (coal and oil) for electric generation	43.7	33.4
Gas in storage – at LIFO cost	18.7	19.5
Total inventories	**$ 96.1**	**$ 86.0**

Based on the average cost of gas purchased during December 2020 and 2019, the cost of replacing gas in storage carried at LIFO cost is less than the carrying value at December 31, 2020 and 2019 by approximately $7 million and $7 million, respectively. All other inventories are carried at average cost. The Company sources most of its coal supply from a single third party and also purchases most of its natural gas from a different single third party. Rates charged to natural gas customers contain a gas cost adjustment clause and electric rates contain a fuel adjustment clause that allow for the timely adjustment in charges to reflect changes in the cost of gas and cost for fuel.

Prepayments & other current assets in the *Balance Sheets* consist of the following:

(In millions)	At December 31, 2020	2019
Prepaid taxes	$ —	$ 7.2
Other	7.9	2.1
Total prepayments & other current assets	**$ 7.9**	**$ 9.3**

Accrued liabilities in the *Balance Sheets* consist of the following:

(In millions)	At December 31, 2020	2019
Accrued taxes	$ 12.5	$ 10.8
Refunds to customers & customer deposits	11.2	12.1
Accrued interest	5.4	5.2
Tax collections payable	0.5	6.1
Accrued salaries & other	7.2	5.3
Total accrued liabilities	**$ 36.8**	**$ 39.5**

Asset retirement obligations included in *Deferred Credits and Other Liabilities* in the *Balance Sheets* roll forward as follows:

(In millions)	2020	2019
Asset retirement obligation, January 1	$ 91.9	$ 64.3
Accretion	1.3	3.2
Changes in estimates, net of cash payments	1.2	24.4
Asset retirement obligation, December 31	**$ 94.4**	**$ 91.9**

Other income – net in the *Statements of Income* consists of the following:

(In millions)	Year ended December 31, 2020	2019
AFUDC – borrowed funds	$ 5.5	$ 4.6
AFUDC – equity funds	7.3	3.5
Pension Settlement Charges	(2.5)	(4.8)
Other	0.8	0.8
Total other income - net	**$ 11.1**	**$ 4.1**

Supplemental Cash Flow Information:

(In millions)	Year ended December 31, 2020	2019
Cash paid (received) for:		
Income taxes	$ (31.3)	$ (0.2)
Interest	32.1	33.5

As of December 31, 2020 and 2019, the Company has accruals related to utility plant purchases totaling approximately $7.9 million and $4.8 million, respectively.

14. Impact of Recently Issued Accounting Standards

The following table provides an overview of recently adopted or issued accounting pronouncements applicable to the Company, unless otherwise noted:

Recently Adopted Accounting Standards

ASU Number and Name	Description	Date of Adoption	Financial Statement Impact upon Adoption
ASU 2016-13- Financial Instruments-Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments	This standard, including standards amending this standard, requires a new model called CECL to estimate credit losses for (1) financial assets subject to credit losses and measured at amortized cost and (2) certain off-balance sheet credit exposures. Upon initial recognition of the exposure, the CECL model requires an entity to estimate the credit losses expected over the life of an exposure based on historical information, current information and reasonable and supportable forecasts, including estimates of prepayments. ***Transition method:*** modified retrospective	January 1, 2020	The Company adopted the standard and there was no impact on results of operations and cash flows. See Note 3 for more information.
ASU 2019-12: Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes	This standard simplifies accounting for income taxes by eliminating certain exceptions to the guidance for intraperiod tax allocation, the methodology for calculating income taxes in an interim period and the recognition of deferred tax liabilities for outside basis differences. It also simplifies aspects of the accounting for franchise taxes that are partially based on income and enacted changes in tax laws or rates and clarifies the accounting for transactions that result in a step-up in the tax basis of goodwill. ***Transition method***: prospective for all amendments that apply to the Company.	January 1, 2020	Upon adoption, the Company is not required to apply the intraperiod tax allocation exception when there is a current-period loss from continuing operations. Accordingly, the Company determined the tax effect of income from continuing operations without considering the tax effects of items that are not included in continuing operations (i.e., discontinued operations). Additionally, the Company is no longer required to limit the year-to-date tax benefit recognized when the year-to-date benefit exceeds the anticipated full year benefit.

Management believed that other recently adopted standards and recently issued standards that are not yet effective will not have a material impact on the Company's financial position, results of operations or cash flows upon adoption.

15. Lease

The Company adopted ASC 842, Leases, and all related amendments on January 1, 2019 using the modified retrospective transition method and elected not to recast comparative periods in the year of adoption as permitted by the standard. There was no adjustment to retained earnings as a result of transition. As a result, disclosures for periods prior to adoption will be presented in accordance with accounting standards in effect for those periods. The Company also elected the package of practical expedients permitted under the transition guidance within the new standard, which among other things, allowed them to carry forward the historical lease classification. Additionally, the Company's elected the practical expedient related to land easements, which allows the carry forward of the accounting treatment for land easements on existing agreements. The total Right of Use (ROU) assets obtained in exchange for new operating lease liabilities upon adoption were $3.0 million.

An arrangement is determined to be a lease at inception based on whether the Company has the right to control the use of an identified asset. ROU assets represent the Company's right to use the underlying asset for the lease term and lease liabilities represent the Company's obligation to make lease payments arising from the lease. ROU assets and liabilities are recognized at the lease commencement date based on the present value of lease payments over the lease term, including payments at commencement that depend on an index or rate. Most leases in which the Company are the lessee do not have a readily determinable implicit rate, so an incremental borrowing rate, based on the information available at the lease commencement dates, utilized to determine the present value of lease payments. When a secured borrowing rate is not readily available, unsecured borrowing rates are adjusted for the effects of collateral to determine the incremental borrowing rate. Lease expense and lease income are recognized on a straight-line basis over the lease term for operating leases.

The Company has lease agreements with lease and non-lease components and have elected the practical expedient to combine lease and non-lease components for certain classes of leases, such as office buildings. For classes of leases in which lease and non-lease components are not combined, consideration is allocated between components based on the stand-alone prices.

The Company's lease agreements do not contain any material residual value guarantees, material restrictions or material covenants. There are no material lease transactions with related parties. Because risk is minimal, the Company does not take any significant actions to manage risk associated with the residual value of their leased assets.

The Company's lease agreements are primarily equipment and real property leases, including land and office facility leases. The Company's lease terms may include options to extend or terminate a lease when it is reasonably certain that those options will be exercised. The Company has elected an accounting policy that exempts leases with terms of one year or less from the recognition requirements of ASC 842.

The components of lease cost, included in *Other Operating* on the Company's *Consolidated Statement of Income*, are as follows:

	Year Ended December 31,	
(In millions)	2020	2019
Operating lease cost	$ 0.6	$ 0.6
Short-term lease cost	1.2	1.0
Total lease cost	$ 1.8	$ 1.6

Supplemental balance sheet information related to lease is as follows:

(In millions, except lease term and discount rate)	December 31 2020		December 31 2019	
Assets:				
Operating ROU assets [1]	$	2.0	$	2.6
Total leased assets	$	2.0	$	2.6
Liabilities:				
Current operating lease liability [2]	$	0.6	$	0.7
Non-current operating lease liability [3]		1.4		1.9
Total lease liabilities	$	2.0	$	2.6
Weighted-average remaining lease term (in years) - operating leases		6.0		6.4
Weighted-average discount rate - operating leases		3.62 %		3.59 %

(1) Reported within Other assets in the Consolidated Balance Sheet

(2) Reported within Current other liabilities in the Consolidated Balance Sheet

(3) Reported within Other liabilities in the Consolidated Balance Sheet

As of December 31, 2020, maturities of operating lease liabilities were as follows:

(In millions)		
2021	$	0.7
2022		0.6
2023		0.5
2024		—
2025		—
2026 and beyond		0.3
Total lease payments	$	2.1
Less: Interest		0.1
Present value of lease liabilities	$	2.0

Other information related to leases is as follows:

(In millions)	Year Ended December 31, 2020	
Operating cash flows from operating leases included in the measurement of lease liabilities	$	0.5
ROU assets obtained in exchange for new operating lease liabilities [1]		—

(1) Includes the transition impact of adoption of ASU 2016-02 Leases as of January 1, 2019.

16. Subsequent Events

On February 4, 2021, the Company's Parent replaced its existing revolving credit facility with a new amended and restated credit facility. The size of the facility remains unchanged and remains guaranteed by Company and the parent's other utilities. Based on the credit ratings as of February 4, 2021, the draw rate would have been LIBOR plus 1.250% under the facility. The credit facility contains provisions relating to the replacement of LIBOR.

In February 2021, an extreme and unprecedented winter weather event resulted in natural gas supply shortages and increased prices of natural gas in the United States, primarily due to prolonged freezing temperatures. The Company has natural gas cost recovery mechanisms to recover the increased cost of natural gas.

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The following discussion and analysis provides additional information regarding Southern Indiana Gas and Electric Company's (the Company) results of operations that is supplemental to, and should be read in conjunction with, the information provided in the Company's 2020 financial statements and notes thereto. The following discussion and analysis should also be read in conjunction with CenterPoint Energy Inc.'s 2020 Annual Report on Form 10-K as it relates to the Company, which includes risk factors and forward looking statements.

The Company generates revenue primarily from the delivery of natural gas and electric service to its customers, and the Company's primary source of cash flow results from the collection of customer bills and the payment for goods and services procured for the delivery of gas and electric services.

Executive Summary of Results of Operations

Operating Results

In 2020, the Company's earnings were $81.9 million compared to $56.5 million in 2019, an increase of $25.4 million. Results in 2020 reflect a $30.0 million reduction in merger and severance expenses following CenterPoint Energy's 2019 acquisition of Vectren, including $17.8 million in severance and $12.2 million in stock-based compensation. Results were partially offset by less favorable weather in 2020 than 2019.

The Regulatory Environment

Gas and electric operations, with regard to retail rates and charges, terms of service, accounting matters, financing, and certain other operational matters, are regulated by the IURC.

In the Company's natural gas service territory, normal temperature adjustment (NTA) and decoupling mechanisms largely mitigate the effect that would otherwise be caused by variations in volumes sold to residential and commercial customers due to weather and changing consumption patterns. In addition to these mechanisms, the commission has authorized gas and electric infrastructure replacement programs, which allow for recovery of these investments outside of a base rate case proceeding. Further, rates charged to natural gas customers contain a gas cost adjustment clause (GCA) and electric rates contain a fuel adjustment clause (FAC). Both of these cost tracker mechanisms allow for the timely adjustment in charges to reflect changes in the cost of gas and cost for fuel. The Company utilizes similar mechanisms for other material operating costs, which allow for changes in revenue outside of a base rate case.

Rate Design Strategies
Sales of natural gas and electricity to residential and commercial customers are largely seasonal and are impacted by weather. Trends in the average consumption among natural gas residential and commercial customers have tended to decline as more efficient appliances and furnaces are installed and the Company's utilities have implemented conservation programs. In the Company's natural gas service territory, NTA and decoupling mechanisms largely mitigate the effect that would otherwise be caused by variations in volumes sold to these customers due to weather and changing consumption patterns.

In the Company's natural gas service territory, the commission has authorized bare steel and cast iron replacement programs. State laws were passed in 2012 and 2013 that expand the ability of utilities to recover, outside of a base rate proceeding, certain costs of federally mandated projects and other significant gas distribution and transmission infrastructure replacement investments. The Company has received approval to implement these mechanisms.

In 2017, the Company's electric service territory started recovering certain costs of electric distribution and transmission infrastructure replacement investments. The electric service territory also currently recovers certain transmission investments outside of base rates. The electric service territory has neither an NTA nor a decoupling mechanism; however, rate designs provide for a lost margin recovery mechanism that works in tandem with conservation initiatives.

Tracked Operating Expenses
Gas costs and fuel costs incurred to serve customers are two of the Company’s most significant operating expenses. Rates charged to natural gas customers contain a GCA. The GCA clause allows the Company to timely charge for changes in the cost of purchased gas, inclusive of unaccounted for gas expense based on actual experience and subject to caps that are based on historical experience. Electric rates contain a FAC that allows for timely adjustment in charges for electric energy to reflect changes in the cost of fuel. The net energy cost of purchased power, subject to an approved variable benchmark based on The New York Mercantile Exchange (NYMEX) natural gas prices, is also timely recovered through the FAC.

GCA and FAC procedures involve periodic filings and IURC hearings to establish price adjustments for a designated future period. The procedures also provide for inclusion in later periods of any variances between actual recoveries representing the estimated costs and actual costs incurred.

The IURC has also applied the statute authorizing GCA and FAC procedures to reduce rates when necessary to limit net operating income to a level authorized in its last general rate order through the application of an earnings test. In the periods presented, the Company has not been impacted by the earnings test.

MISO charges and other reliability costs and revenues incurred to serve retail electric customers are recovered through the RCRA and MCRA. MISO charges include specific charges under the MISO’s FERC approved tariff for items such as reactive power, scheduling, and transmission network charges that are socialized among various MISO members. Reliability costs and revenues include non-fuel costs of purchased power and costs and credits associated with certain interruptible customers.

Gas pipeline integrity management operating costs, costs to fund energy efficiency programs, MISO costs, and the gas cost component of uncollectible accounts expense based on historical experience are recovered by mechanisms outside of typical base rate recovery. In addition, certain operating costs, including depreciation associated with federally mandated investments, gas and electric distribution and transmission infrastructure replacement investments, and regional electric transmission assets not in base rates are also recovered by mechanisms outside of typical base rate recovery.

Revenues and margins are also impacted by the collection of state mandated taxes, which primarily fluctuate with gas and fuel costs.

Base Rate Orders
The Company's electric territory received an order in April 2011, with rates effective May 2011, and its gas territory received an order and implemented rates in August 2007. The orders authorize a return on equity of 10.40% on the electric operations and 10.15% for the gas operations. The authorized returns reflect the impact of rate design strategies that have been authorized by the IURC.

On October 30, 2020, and as subsequently amended, the Company filed its base rate case with the IURC seeking approval for a revenue increase of approximately $29 million. This rate case filing is required under Indiana TDSIC statutory requirements before the completion of the Company's capital expenditure program, approved in 2014 for investments starting in 2014 through 2020. The revenue increase is based upon a requested ROE of 10.15% and an overall after-tax rate of return of 5.99% on total rate base of approximately $469 million. The Company has utilized a projected test year, reflecting its 2021 budget as the basis for the revenue increase requested, and proposes to implement rates in two phases. The first phase of rate implementation will occur as of the date of an order in this proceeding, expected in September 2021, and the second phase of rate implementation will occur at the completion of the test year, as of December 31, 2021. Under Indiana statutory requirements, the IURC has a minimum 300 days and maximum of 360 days from the date of the filing of the Company's case- in-chief to issue an order.

See Note 9 to the financial statements for more specific information on the significant regulatory proceedings involving the Company.

Operating Trends

Margin

Throughout this discussion, the terms Natural Gas margin and Electric margin are used. Natural Gas margin is calculated as *Natural Gas revenues* less the *Cost of gas sold*. Electric margin is calculated as *Electric revenues* less *Cost of fuel & purchased power*. The Company believes Natural Gas and Electric margins are better indicators of relative contribution than revenues since gas prices and fuel and purchased power costs can be volatile and are generally collected on a dollar-for-dollar basis from customers.

In addition, the Company separately reflects regulatory expense recovery mechanisms within Natural Gas margin and Electric margin. These amounts represent dollar-for-dollar recovery of other operating expenses. The Company utilizes these approved regulatory mechanisms to recover variations in operating expenses from the amounts reflected in base rates and are generally expenses that are subject to volatility. Following is a discussion and analysis of margin.

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

	Year Ended December 31,	
(In thousands)	2020	2019
Electric revenues	$ 554,511	$ 570,150
Cost of fuel & purchased power	147,369	165,900
Total Electric margin	**$ 407,142**	**$ 404,250**
Margin attributed to:		
Residential & commercial customers	$ 257,432	$ 255,545
Industrial customers	91,640	95,107
Other	5,182	6,194
Regulatory expense recovery mechanisms	21,155	17,456
Subtotal: Retail	**375,409**	**374,302**
Wholesale margin	31,733	29,948
Total Electric margin	**$ 407,142**	**$ 404,250**
Electric volumes sold in MWh attributed to:		
Residential & commercial customers	2,502,396	2,608,827
Industrial customers	1,971,237	2,072,912
Other customers	20,915	21,113
Total retail volumes	**4,494,548**	**4,702,852**
Wholesale	384,752	495,281
Total volumes sold	**4,879,300**	**5,198,133**

Retail
Electric retail utility margins were $375.4 million for the year ended December 31, 2020, compared to $374.3 million in 2019, an increase of $1.1 million. Results primarily reflect an increase in margin of $4.9 million as a result of the Clean Energy Cost Adjustment and Environmental Cost Adjustment (CECA and ECA) and a $7.8 million increase resulting from the Transmission, Distribution and Storage System Improvement Charge (TDSIC). The increase was partially offset by a $4.5 million decrease in margin due to less favorable weather along with a $4.5 million decrease in margin resulting from a decline in large industrial customer usage and pricing, and a $1.7 million decrease in margin due to residential and commercial customer pricing. Heating degree days were 89 percent of normal in 2020 compared to 95 percent of normal in 2019, and cooling degree days were 106 percent of normal in 2020 compared to 115 percent of normal in 2019.

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

	Year Ended December 31,	
(In thousands)	2020	2019
MISO transmission system margin	$ 26,246	$ 24,957
MISO off-system margin	5,487	4,991
Total wholesale margin	**$ 31,733**	**$ 29,948**

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms and other transmission system operations, totaled $26.2 million during 2020 compared to $25.0 million in 2019, an increase of $1.2 million.

For the year ended December 31, 2020, margin from off-system sales was $5.5 million compared to $5.0 million in 2019, an increase of $0.5 million. The base rate changes implemented in May 2011 require wholesale margin from off-system sales earned above or below $7.5 million per year to be shared equally with customers.

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

	Year Ended December 31,	
(In thousands)	2020	2019
Natural Gas revenues	$ 99,510	$ 99,531
Cost of gas sold	27,999	33,623
Total Natural Gas margin	**$ 71,511**	**$ 65,908**
Margin attributed to:		
Residential & commercial customers	$ 49,501	$ 45,316
Industrial customers	11,435	10,781
Other	630	852
Regulatory expense recovery mechanisms	9,945	8,959
Total Natural Gas margin	**$ 71,511**	**$ 65,908**
Sold & transported volumes in MDth attributed to:		
Residential & commercial customers	$ 9,712	$ 10,439
Industrial customers	26,461	30,170
Total sold & transported volumes	**$ 36,173**	**$ 40,609**

Natural Gas margin was $71.5 million for the year ended December 31, 2020 compared to $65.9 million in 2019, an increase of $5.6 million. The increase in margin was largely due to increased returns on the Compliance and System Improvement Adjustment (CSIA). Weather has relatively no impact on customer margin due to the Company's rate design. The decrease in sold and transported volumes was primarily due to weather. Heating degree days were 89 percent of normal in 2020 compared to 95 percent of normal in 2019.

Operating Expenses

Other Operating
For the year ended December 31, 2020, *Other operating* expenses were $216.6 million compared to $241.9 million in 2019, a decrease of $25.3 million. Operating expenses primarily reflect a decrease of $30.0 million from 2019 merger and severance

expenses following CenterPoint Energy’s acquisition of Vectren and offset by a $3.7 million increase due to operating expenses recovered through margin.

Depreciation & Amortization

Depreciation and amortization expense was $119.6 million in 2020, compared to $114.0 million in 2019, an increase of $5.6 million. The increase resulted from additional utility plant investments placed into service.

SELECTED ELECTRIC OPERATING STATISTICS

	For the Year Ended December 31, 2020	2019
OPERATING REVENUES (in thousands):		
Residential	$ 209,034	$ 210,443
Commercial	144,342	148,094
Industrial	153,213	159,892
Other	8,065	9,355
Total Retail	514,654	527,784
Net Wholesale Revenues	39,857	42,366
	$ 554,511	$ 570,150
MARGIN (In thousands):		
Residential	$ 157,437	$ 153,801
Commercial	99,995	101,744
Industrial	91,640	95,107
Other	5,182	6,194
Regulatory expense recovery mechanisms	21,155	17,456
Total Retail	375,409	374,302
Wholesale power & transmission system	31,733	29,948
	$ 407,142	$ 404,250
ELECTRIC SALES (In MWh):		
Residential	1,385,114	1,409,212
Commercial	1,117,282	1,199,615
Industrial	1,971,237	2,072,912
Other Sales - Street Lighting	20,915	21,113
Total Retail	4,494,548	4,702,852
Wholesale	384,752	495,281
	4,879,300	5,198,133
CUSTOMER COUNT:		
Residential	130,159	128,947
Commercial	18,971	18,837
Industrial	116	116
Other	43	42
	149,289	147,942
WEATHER AS A % OF NORMAL:		
Cooling Degree Days	106 %	115 %
Heating Degree Days	89 %	95 %

SELECTED GAS OPERATING STATISTICS

	For the Year Ended December 31, 2020	2019
OPERATING REVENUES (in thousands):		
Residential	$ 64,378	$ 64,743
Commercial	22,235	22,507
Industrial	12,920	12,039
Other	(23)	242
	$ 99,510	$ 99,531
MARGIN (In thousands):		
Residential	$ 39,027	$ 35,690
Commercial	10,474	9,626
Industrial	11,436	10,781
Other	630	852
Regulatory expense recovery mechanisms	9,945	8,959
	$ 71,512	$ 65,908
GAS SOLD & TRANSPORTED (In MDth):		
Residential	6,268	6,713
Commercial	3,444	3,726
Industrial	26,461	30,170
	36,173	40,609
CUSTOMER COUNT		
Residential	103,560	102,680
Commercial	10,452	10,400
Industrial	113	113
	114,125	113,193