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 8, 2024**

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 NYSE Chicago

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

Emerging Growth Company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Item 7.01. Regulation FD Disclosure.

Included herein is financial information related to Southern Indiana Gas & Electric Company (“CEI South”). CEI South is a wholly-owned subsidiary of Vectren Utility Holdings, LLC ("VUH"). VUH is a wholly-owned subsidiary of Vectren, LLC (“Vectren”), which in turn, is an indirect, wholly-owned subsidiary of CenterPoint Energy, Inc. (“CenterPoint Energy”).

Exhibit 99.1 to this Current Report on Form 8-K includes audited financial statements for the years ended December 31, 2023 and 2022 for CEI South. These financial statements are not intended to comply with Regulation S-X or Regulation S-K. Exhibit 99.2 includes certain supplementary financial and operational data of CEI South for the years ended December 31, 2023 and 2022.

Each of Exhibits 99.1 and 99.2 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 and 99.2 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 and 99.2 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 and 99.2 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 Southern Indiana Gas & Electric Company
99.2	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 8, 2024	By: /s/ Kristie L. Colvin
	Kristie L. Colvin
	Senior Vice President and Chief Accounting Officer

SOUTHERN INDIANA GAS & ELECTRIC COMPANY
CONSOLIDATED FINANCIAL STATEMENTS

As of and for the years ended December 31, 2023 and 2022

Contents

DEFINITIONS

ACE	Affordable Clean Energy
AFUDC	Allowance for funds used during construction
AGC	Alcoa Generating Corporation, a subsidiary of Alcoa, Inc.
AMA	Asset Management Agreement
Arevon	Arevon Energy, Inc., which was formed through the combination of Capital Dynamics, Inc.’s U.S. Clean Energy Infrastructure business unit and Arevon Asset Management
ARO	Asset Retirement Obligation
ARP	Alternative Revenue Program
ASC	Accounting Standards Codification
BTA	Build Transfer Agreement
CAMT	Corporate Alternative Minimum Tax
CCR	Coal Combustion Residuals
CECA	Clean Energy Cost Adjustment
CODM	Chief Operating Decision Maker
CPCN	Certificate of Public Convenience and Necessity
CPP	Clean Power Plan
CSIA	Compliance and System Improvement Adjustment
DOC	U.S. Department of Commerce
DSMA	Demand Side Management Adjustment
ECA	Environmental Cost Adjustment
EIA	U.S. Energy Information Administration
ELG	Effluent Limitation Guidelines
EPA	Environmental Protection Agency
FASB	Financial Accounting Standards Board
February 2021 Winter Storm Event	The extreme and unprecedented winter weather event in February 2021 resulting in electricity generation supply shortages, including in Texas, and natural gas supply shortages and increased wholesale prices of natural gas in the United States, primarily due to prolonged freezing temperatures.
FERC	Federal Energy Regulation Commission
GAAP	Generally Accepted Accounting Principles
GHG	Greenhouse gases
IDEM	Indiana Department of Environmental Management
IRA	Inflation Reduction Act of 2022
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
ITCs	Investment Tax Credits
IURC	Indiana Utility Regulatory Commission
LIFO	Last In - First Out inventory method
LMP	Locational Marginal Pricing
Merger	The merger of Merger Sub with and into Vectren on the terms and subject to the conditions set forth in the Merger Agreement, with Vectren continuing as the surviving corporation and as a wholly-owned subsidiary of CenterPoint Energy, Inc., which closed on the Merger Date
Merger Agreement	Agreement and Plan of Merger, dated as of April 21, 2018, among CenterPoint Energy, Vectren and Merger Sub
Merger Date	February 1, 2019
Merger Sub	Pacer Merger Sub, Inc., an Indiana corporation and wholly-owned subsidiary of CenterPoint Energy
MGP	Manufactured gas plant

MISO	Midcontinent Independent System Operator
MW	Megawatts
NYMEX	New York Mercantile Exchange
Oriden	Oriden LLC
Origis	Origis Energy USA Inc.
OUCC	Indiana Office of Utility Consumer Counselor
PCB	Polychlorinated Biphenyl
Posey Solar	Posey Solar, LLC, a Delaware limited liability company
PPA	Power purchase agreement
PRP	Potentially responsible parties
PTCs	Production Tax Credits
RCRA	Resource Conservation and Recovery Act of 1976
ROE	Return on equity
Scope 1 emissions	Direct source of emissions from a company’s operations
Scope 2 emissions	Indirect source of emissions from a company’s energy usage
Scope 3 emissions	Indirect source of emissions from a company’s end-users
Securitization Bonds	Securitization Subsidiary’s Series 2023-A Senior Secured Securitization Bonds
Securitization Subsidiary	SIGECO Securitization I, LLC, a direct, wholly-owned subsidiary of the Company
SERP	Supplemental Executive Retirement Plan
SOFR	Secured Overnight Financing Rate
TCJA	Tax reform legislation informally called the Tax Cuts and Jobs Act of 2017
TDSIC	Transmission, Distribution and Storage System Improvement Charge
Vectren	Vectren, LLC, which converted its corporate structure from Vectren Corporation to a limited liability company on June 30, 2022, a wholly-owned subsidiary of CenterPoint Energy, Inc. as of the Merger Date, and, after the Restructuring, is held indirectly by CenterPoint Energy through Vectren Affiliated Utilities, Inc.
VIE	Variable interest entity
VRP	Voluntary Remediation Program
VUH	Vectren Utility Holdings, LLC, which converted its corporate structure from Vectren Utility Holdings, Inc. to a limited liability company on June 30, 2022, a wholly-owned subsidiary of Vectren LLC

INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of Southern Indiana Gas and Electric Company:

Opinion

We have audited the consolidated financial statements of Southern Indiana Gas and Electric Company (the “Company”) (a wholly owned subsidiary of Vectren Utility Holdings, LLC), which comprise the consolidated balance sheets as of December 31, 2023 and 2022, and the related consolidated statements of income, shareholder’s equity, and cash flows for the years then ended, and the related notes to the financial statements (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2023 and 2022, 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.

Basis for Opinion

We conducted our audits in accordance with auditing standards generally accepted in the United States of America (GAAS). Our responsibilities under those standards are further described in the Auditor’s Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audits. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America, and for 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.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company’s ability to continue as a going concern for one year after the date that the financial statements are issued.

Auditor’s Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor’s report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.

- Obtain an understanding of internal control relevant to the audit 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, no such opinion is expressed.

- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.

- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

Other Information Included in the Annual Report

Management is responsible for the other information included in the annual report. The other information comprises the information included in the annual report but does not include the financial statements and our auditor's report thereon. Our opinion on the financial statements does not cover the other information, and we do not express an opinion or any form of assurance thereon.

In connection with our audits of the financial statements, our responsibility is to read the other information and consider whether a material inconsistency exists between the other information and the financial statements, or the other information otherwise appears to be materially misstated. If, based on the work performed, we conclude that an uncorrected material misstatement of the other information exists, we are required to describe it in our report.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
March 8, 2024

FINANCIAL STATEMENTS

SOUTHERN INDIANA GAS & ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS

	December 31, 2023	December 31, 2022
	(in millions)	
ASSETS		
Current Assets		
Cash and cash equivalents ($14 and $-0- related to VIEs, respectively)	$ 14	$ 5
Accounts receivable ($2 and $-0- related to VIEs, respectively), less allowance for credit losses of 2 and $3, respectively	47	62
Accrued unbilled revenues ($2 and $-0- related to VIEs, respectively), less allowance for credit losses of $-0- and $-0-, respectively	45	40
Inventories	96	103
Regulatory assets	—	49
Prepaid expenses and other current assets ($2 and $-0- related to VIEs, respectively)	44	23
Total current assets	246	282
Property, Plant and Equipment		
Property, plant and equipment	$ 4,625	$ 4,956
Less: accumulated depreciation & amortization	1,636	2,068
Property, Plant and Equipment, net	2,989	2,888
Other Assets:		
Goodwill	6	6
Regulatory assets ($329 and $-0- related to VIEs, respectively)	547	191
Other non-current assets	52	53
Total other assets	605	250
Total Assets	$ 3,840	$ 3,420

The accompanying notes are an integral part of these financial statements

SOUTHERN INDIANA GAS & ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS

	December 31, 2023	December 31, 2022
	(in millions)	
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current Liabilities:		
Accounts payable	$ 95	$ 126
Accounts and notes payable - affiliated companies	75	47
Accrued liabilities	93	60
Current maturities of long-term debt - VIE Securitization Bonds	17	—
Current maturities of long-term debt - third parties	23	11
Current maturities of long-term debt - affiliated companies	—	25
Total current liabilities	303	269
Other Liabilities:		
Deferred income taxes	309	296
Regulatory liabilities	300	288
Other non-current liabilities	206	197
Total other liabilities	815	781
Long-term Debt:		
Long-term debt - VIE Securitization Bonds, net	320	—
Long-term debt - third parties, net	821	277
Long-term debt - affiliated companies, net	256	755
Total long-term debt	1,397	1,032
Commitments and Contingencies (Note 8)		
Shareholder's equity:		
Common stock (no par value)	539	539
Retained earnings	786	799
Total shareholder's equity	1,325	1,338
Total Liabilities and Shareholder's Equity	$ 3,840	$ 3,420

The accompanying notes are an integral part of these financial statements

SOUTHERN INDIANA GAS & ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,	
	2023	2022
	(in millions)	
Revenues:		
Electric utility revenues	$ 595	$ 696
Gas utility revenues	128	146
Securitization subsidiary	17	—
Total	740	842
Expenses:		
Fuel and purchased power	176	222
Utility natural gas	30	58
Operation and maintenance	251	247
Depreciation and amortization, excluding Securitization subsidiary	138	144
Amortization - Securitization subsidiary	8	—
Taxes other than income taxes	12	18
Total operating expenses	615	689
Operating Income	125	153
Other Income (Expense):		
Interest expense	(50)	(33)
Interest expense - Securitization subsidiary	(9)	—
Other income, net	35	16
Income Before Income Taxes	101	136
Income tax expense	21	27
Net Income	$ 80	$ 109

The accompanying notes are an integral part of these financial statements

SOUTHERN INDIANA GAS & ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,	
	2023	2022
Cash Flows from Operating Activities:	(in millions)	
Net income	$ 80	$ 109
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	146	144
Deferred income taxes and investment tax credits	8	36
Expense portion of pension and postretirement benefit cost	—	(2)
Changes in working capital accounts:		
Accounts receivable & accrued unbilled revenue	8	(22)
Accounts payable, affiliates	13	(8)
Accounts payable	(13)	22
Inventories	6	(31)
Net regulatory assets and liabilities	(23)	(17)
Other current assets and liabilities	11	(11)
Other non-current assets and liabilities	1	(13)
Other operating activities, net	(11)	(6)
Net cash provided by operating activities	226	201
Cash Flows from Investing Activities:		
Capital expenditures	(495)	(363)
Other investing activities, net	4	(3)
Net cash used in investing activities	(491)	(366)
Cash Flows from Financing Activities:		
Net change in short-term notes payable - affiliated companies	14	(32)
Proceeds from long-term notes payable - affiliated companies	—	140
Payment of long-term notes payable - affiliated companies	(524)	(5)
Proceeds from long-term debt - third parties	650	—
Payment of long-term debt - third parties, including make-whole premiums	(102)	—
Proceeds of VIE Securitization Bonds	341	—
Debt issuance cost	(9)	—
Contributions from VUH	—	102
Dividends to VUH	(93)	(37)
Net cash provided by financing activities	277	168
Net Increase in Cash, Cash Equivalents and Restricted Cash	12	3
Cash, Cash Equivalents and Restricted Cash at Beginning of Year	5	2
Cash, Cash Equivalents and Restricted Cash at End of Year	$ 17	$ 5

The accompanying notes are an integral part of these financial statements

SOUTHERN INDIANA GAS & ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY

	Common Stock	Retained Earnings	Total Shareholder's Equity
		(in millions)	
Balance at January 1, 2022	$ 433	$ 727	$ 1,160
Net income	—	109	109
Contribution from VUH	102	—	102
Non-cash contribution from VUH	4	—	4
Dividends to VUH	—	(37)	(37)
Balance at December 31, 2022	$ 539	$ 799	$ 1,338
Net income	—	80	80
Dividends to VUH	—	(93)	(93)
Balance at December 31, 2023	$ 539	$ 786	$ 1,325

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 "CEI South"), an Indiana corporation, provides energy delivery services to 152,493 electric customers and 115,331 gas customers located near Evansville in southwestern Indiana. Of these customers, 87,758 receive combined electric and gas distribution services. The Company also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. The Company is a direct, wholly owned subsidiary of VUH (the Company's parent). VUH is a direct, wholly owned subsidiary of Vectren. Vectren, an indirect, wholly owned subsidiary of CenterPoint Energy, Inc. (collectively with its subsidiaries, "CenterPoint Energy"), is an energy holding company headquartered in Evansville, Indiana.

(2) Summary of Significant Accounting Policies

(a) Basis of Presentation and Principles of Consolidation

The accompanying consolidated financial statements have been prepared in conformity with generally accepted accounting principles. The accounts of the Company and its wholly-owned subsidiary are included in the consolidated financial statements. All intercompany transactions and balances are eliminated in consolidation, except as described below.

As of December 31, 2023, the Company has a VIE Securitization Subsidiary, which is consolidated. The consolidated VIE is a wholly-owned, bankruptcy-remote, special purpose entity that was formed solely for the purpose of securitizing transition property or facilitating the securitization financing of qualified costs in the second quarter of 2023 associated with the completed retirement of the Company's A.B. Brown coal generation facilities. The Company has a controlling financial interest in the Securitization Subsidiary and is the VIE's primary beneficiary. For further information, see Note 9. Creditors of the Company have no recourse to any assets or revenues of the Securitization Subsidiary, as applicable. The Securitization Bonds issued by the VIE is payable only from and secured by securitization property and the bondholders have no recourse to the general credit of the Company.

(b) Use of Estimates

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 property, plant and equipment 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.

(c) Cash & Cash Equivalents

For purposes of reporting cash flows, the Company considers cash equivalents to be short-term, highly-liquid investments with maturities of three months or less from the date of purchase. Cash and cash equivalents held by the Company's Securitization Subsidiary (VIE) solely to support servicing the Securitization Bonds as of December 31, 2023 is reflected on the Company's Consolidated Balance Sheets. Cash and cash equivalents are stated at cost plus accrued interest to approximate fair value.

In connection with the issuance of Securitization Bonds, the Company was required to establish restricted cash accounts to collateralize the bonds that were issued in these financing transactions. These restricted cash accounts are not available for withdrawal until the maturity of the bonds and are not included in cash and cash equivalents. For more information on restricted cash, see Note 13.

(d) Accounts Receivable and Allowance for Credit Losses

Accounts receivable are recorded at the invoiced amount and do not bear interest. The Company 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 it is probable the receivable will not be recovered.

(e) 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 LIFO method. Inventory is valued at historical cost consistent with ratemaking treatment. Materials and supplies are valued at the lower of average cost or market, and are recorded as inventory when purchased and subsequently charged to expense or capitalized to plant when installed.

Inventories consist of the following:

	December 31,	
	2023	2022
	(in millions)	
Materials & supplies	$ 56	$ 57
Coal & oil for electric generation - at average cost	19	27
Natural gas in storage – at LIFO cost	21	19
Total inventories	$ 96	$ 103

Based on the average cost of natural gas purchased during December 2023 and 2022, the cost of replacing natural gas in storage carried at LIFO cost is less than the carrying value as of December 31, 2023 and 2022 by $5 million and less than $1 million, respectively. The Company sources most of its coal supply from one 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.

(f) Long-lived Assets and Goodwill

The Company records property, plant and equipment at historical cost and expenses repair and maintenance costs as incurred.

The Company periodically evaluates long-lived assets, including property, plant and equipment, 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 impairments were recorded in 2023 or 2022.

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. Goodwill is reported in the Company's Natural Gas reporting segment.

The Company performed the annual goodwill impairment tests in the third quarter of 2023 and determined that no goodwill impairment charge was required.

(g) Depreciation and Amortization Expense

The Company computes depreciation and amortization using the straight-line method based on economic lives or regulatory-mandated recovery periods. Amortization expense includes amortization of certain regulatory assets.

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

(h) Capitalization of AFUDC

The Company capitalizes AFUDC as a component of projects under construction and amortizes it over the assets' estimated useful lives once the assets are placed in service. Additionally, the Company defers interest costs into a regulatory asset when amounts are probable of recovery. Deferred debt interest is amortized over the recovery period for rate-making purposes. AFUDC represents the composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction as the Company applies the guidance for accounting for regulated operations. Although AFUDC increases both property, plant and equipment and earnings, it is realized in cash when the assets are included in rates. The table below sets forth capitalized AFUDC and deferred debt interest costs for the periods presented:

	Year Ended December 31,	
	2023	2022
	(in millions)	
AFUDC – borrowed funds (1)	$ 8	$ 4
AFUDC – equity funds (1)	16	8
Deferred debt interest (2)	5	3

(1) Included in Other income, net on the Company's Consolidated Statements of Income.
(2) Represents the amount of deferred debt interest on certain regulatory assets that are authorized to earn a return, such as debt post in-service carrying costs on property, plant and equipment.

(i) 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 this agency.

(j) Refundable or Recoverable Gas Costs and Cost of Fuel and 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.

(k) Regulatory Assets and Liabilities

The Company applies the guidance for accounting for regulated operations within its Electric and Natural Gas reportable segments. The Company's rate-regulated subsidiaries may collect revenues subject to refund pending final determination in rate proceedings. In connection with such revenues, estimated rate refund liabilities are recorded which reflect management's current judgment of the ultimate outcomes of the proceedings.

The Company's rate-regulated businesses recognize removal costs as a component of depreciation expense in accordance with regulatory treatment. In addition, a portion of the amount of removal costs collected from customers that relate to AROs has been reflected as an asset retirement liability in accordance with accounting guidance for AROs.

(l) Asset Retirement Obligations

A portion of removal costs related to interim retirements of gas utility pipeline and electric utility poles, and reclamation activities meet the definition of an ARO. The Company records the fair value of a liability for an ARO in the period in which the legal obligation is incurred if a reasonable estimate of fair value and its settlement date can be made. 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. The estimates of future liabilities are developed using a discounted cash flow model based upon estimates and assumptions of future costs, interest rates, credit-adjusted risk-free rates and the estimated timing of settlement.

(m) Derivative Instruments

The Company is exposed to various market risks. These risks arise from transactions entered into in the normal course of business. The Company, from time to time, utilizes derivative instruments such as physical forward contracts, to mitigate the impact of changes in commodity prices on operating results and cash flows. Such derivatives are recognized in the Company's Balance Sheet at their fair value unless the Company elects the normal purchase and sales exemption for qualified physical transactions. A derivative may be designated as a normal purchase or normal sale if the intent is to physically receive or deliver the product for use or sale in the normal course of business.

(n) Environmental Costs

The Company expenses or capitalizes environmental expenditures, as appropriate, depending on their future economic benefit. The Company expenses amounts that relate to an existing condition caused by past operations that do not have future economic benefit. The Company records undiscounted liabilities related to these future costs when environmental assessments and/or remediation activities are probable and the costs can be reasonably estimated.

(o) Income Taxes

The Company is 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 basis. 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 its Consolidated Statements of Income.

To the extent certain excess deferred income taxes of the Company 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. Production tax credits extended by the IRA may be used to reduce current federal income taxes payable.

(p) Revenue Recognition

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.

(q) 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 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 and Fuel and purchased power, and net sales within that interval are recorded on the Company's Consolidated Statements of Income in Electric utility revenues. On occasion, prior period transactions are resettled outside the routine process due to a change in the MISO's tariff or a material interpretation thereof. Expenses associated with resettlements are recorded once the resettlement is probable and the resettlement amount can be estimated. Revenues associated with resettlements are recognized when the amount is determinable and collectability is reasonably assured.

The Company also receives transmission revenue that results from transmission customers' 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.

(r) 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 was less than $1 million in 2023 and $5 million in 2022. Expense associated with utility receipts taxes are recorded as a component of Taxes other than income taxes on the Statements of Income. The Indiana utility receipts tax was repealed as of July 1, 2022. The utility receipts tax rate was removed from Indiana rates at the time of the repeal. The Company filed its final utility receipts tax return on April 4, 2023.

(s) 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 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.

(t) 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).

(u) New Accounting Pronouncements

In November 2023, the FASB issued ASU 2023-07, Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures ("ASU 2023-07"). This ASU updates segment disclosure requirements through enhanced disclosures around significant segment expenses. ASU 2023-07 is effective for fiscal years beginning after December 15, 2023, and for interim periods within fiscal years beginning after December 15, 2024. Early adoption is permitted. The Company is currently evaluating the impact of this ASU on their respective consolidated financial statements.

In December 2023, the FASB issued ASU 2023-09, Income Taxes (Topic 740): Improvements to Income Tax Disclosures ("ASU 2023-09"). This ASU enhances the transparency of income tax disclosures related to rate reconciliation and income taxes. ASU 2023-09 is effective for annual periods beginning after December 15, 2025. Early adoption is permitted. The Company is currently evaluating the impact of this ASU on its consolidated financial statements.

Management believes that all other recently adopted and recently issued accounting 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.

(3) Revenue Recognition

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 or in a regulatory asset, as applicable. 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 ARPs, which are excluded from the scope of ASC 606. Revenues from ARPs 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. These revenues are not subject to significant returns, refunds, or warranty obligations.

In the following table, the Company's revenue is disaggregated by reportable segment and major source.

	Year Ended December 31, 2023		
	Electric (1)	**Natural Gas**	**Total**
		(in millions)	
Revenue from contracts with customers	$ 591	$ 124	$ 715
Other (2)	21	4	25
Total Revenues	$ 612	$ 128	$ 740

	Year Ended December 31, 2022		
	Electric	**Natural Gas**	**Total**
		(in millions)	
Revenue from contracts with customers	$ 677	$ 146	$ 823
Other (2)	19	—	19
Total Revenues	$ 696	$ 146	$ 842

(1) Includes Securitization subsidiary revenues from contracts with customers.

(2) Primarily consists of income from ARPs. ARPs are contracts between the utility and its regulators, not between the utility and a customer. The Company recognizes ARP revenue as other revenues when the regulator-specified conditions for recognition have been met. Upon recovery of ARP revenue through incorporation in rates charged for utility service to customers, ARP revenue is reversed and recorded as revenue from contracts with customers. The recognition of ARP revenues and the reversal of ARP revenues upon recovery through rates charged for utility service may not occur in the same period.

Revenues from Contracts with Customers

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.

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

	Accounts Receivable	Other Accrued Unbilled Revenues
	(in millions)	
Opening balance as of December 31, 2022	$ 62	$ 40
Closing balance as of December 31, 2023	47	45
Increase (decrease)	$ (15)	$ 5

Allowance for Credit Losses and Bad Debt Expense

The Company segregates financial assets that fall under the scope of Topic 326, primarily trade receivables due in one year or less, into portfolio segments based on shared risk characteristics, such as geographical location and regulatory environment, for evaluation of expected credit losses. Historical and current information, such as average write-offs, are applied to each portfolio segment to estimate the allowance for losses on uncollectible receivables. Additionally, the allowance for losses on uncollectible receivables is adjusted for reasonable and supportable forecasts of future economic conditions, which can include changing weather, commodity prices, regulations, and macroeconomic factors, among others.

The table below summarizes the Company's bad debt expense amounts for 2023 and 2022, net of regulatory deferrals:

	Year Ended December 31,	
	2023	2022
	(in millions)	
Bad debt expense	$ 2	$ 3

(4) Property, Plant and Equipment

(a) Property, Plant and Equipment

Property, plant and equipment includes the following:

		December 31, 2023			December 31, 2022		
	Weighted Average Useful Lives	Property, Plant and Equipment, Gross	Accumulated Depreciation and Amortization	Property, Plant and Equipment, Net	Property, Plant and Equipment, Gross	Accumulated Depreciation and Amortization	Property, Plant and Equipment, Net
	(in years)	(in millions)					
Electric transmission and distribution	34	$ 2,351	$ 1,121	$ 1,230	$ 2,063	$ 1,066	$ 997
Electric generation (1)	25	1,381	315	1,066	2,120	813	1,307
Natural gas distribution	42	893	200	693	773	189	584
Total		$ 4,625	$ 1,636	$ 2,989	$ 4,956	$ 2,068	$ 2,888

(1) The Company and AGC own a 300 MW unit at the Warrick Power Plant (Warrick Unit 4) as tenants in common as of December 31, 2023. The Company's share of the cost of this unit as of December 31, 2023, is $198 million with accumulated depreciation totaling $171 million. Under the operating agreement, AGC and the Company shared equally in the cost of operation and output of the unit. The Company's share of operating costs is included in Operation and maintenance expense in the Company's Consolidated Statements of Income. The Company exited joint operations of Warrick 4 on January 1, 2024.

(b) Depreciation and Amortization

The following table presents depreciation and amortization expense:

	Year Ended December 31,	
	2023	2022
	(in millions)	
Depreciation	$ 137	$ 142
Amortization of regulatory assets (1)	9	2
Total	$ 146	$ 144

(1) For the year ended December 31, 2023, includes amortization expense of $8 million related to the Securitization subsidiary reflected on the Company's Consolidated Statements of Income.

(c) ARO

The Company recorded AROs relating to the closure of the ash ponds at A.B. Brown and F.B. Culley and for treated wood poles for electric distribution, distribution transformers containing PCB, and underground fuel storage tanks. The Company also recorded AROs relating to gas pipelines abandoned in place.

A reconciliation of the changes in the ARO liability recorded in Other non-current liabilities in the Company’s Consolidated Balance Sheets is as follows:

	Year Ended December 31,	
	2023	2022
	(in millions)	
Beginning balance	$ 139	$ 124
Accretion expense (1)	9	4
Revisions in estimates (2)	4	11
Ending balance	$ 152	$ 139

(1) Reflected in non-current Regulatory assets on the Company’s Balance Sheets.
(2) In 2023 and 2022, the Company reflected an increase in its ARO liability, which is primarily attributable to a revision to the ARO for Culley East ash pond regarding the change in estimated future cash flows. In 2023, the Company's increase was also attributable to a revision to the ARO for AB Brown ash pond regarding the change in estimated future cash flows.

(5) Regulatory Assets & Liabilities

The following is a list of regulatory assets and liabilities reflected on the Company's Balance Sheets as of December 31, 2023 and 2022:

	December 31,	
	2023	2022
	(in millions)	
Regulatory Assets:		
Future amounts recoverable from ratepayers related to:		
Asset retirement obligations & other	$ 39	$ 30
Net deferred income taxes	13	9
Total future amounts recoverable from ratepayers	52	39
Amounts deferred for future recovery related to:		
Cost recovery riders	48	70
Total amounts deferred for future recovery	48	70
Amounts currently recovered through customer rates related to:		
Authorized trackers and cost deferrals (1)	424	82
Gas recovery costs (2)	—	49
Loss on reacquired debt and hedging costs	23	—
Total amounts recovered in customer rates	447	131
Total Regulatory Assets	$ 547	$ 240
Total Current Regulatory Assets	$ —	$ 49
Total Non-current Regulatory Assets	$ 547	$ 191
Regulatory Liabilities:		
Regulatory liabilities related to TCJA	$ 175	$ 182
Estimated removal costs	81	83
Other regulatory liabilities	44	23
Total Regulatory Liabilities	$ 300	$ 288

(1) Includes the securitized regulatory assets discussed below in *Securitization of Generation Retirements*.
(2) Included in current regulatory assets on the Company's Balance Sheets.

Of the $447 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 $35 million, is 18 years. Regulatory assets not earning a return with perpetual or undeterminable lives have been excluded from the weighted average recovery period calculation. 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 primarily a result of costs incurred for expected retirement activity for the Company's ash ponds beyond what has been recovered in rates. See Notes 4 and 10 for further information. The Company believes the recovery of these assets are probable as the costs are currently being recovered in rates.

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.

For further information about the Company's regulatory matters, see Note 9.

Securitization of Generation Retirements

On January 4, 2023, the IURC issued an order in accordance with Indiana Senate Enrolled Act 386 authorizing the issuance of up to $350 million in securitization bonds to securitize qualified costs associated with the retirements of the Company's A.B.

Brown coal-fired generation facilities. Accordingly, the Company determined that the retirement of property, plant and equipment became probable upon the issuance of the order. No loss on abandonment was recognized in connection with issuance of the order as there was no disallowance of all or part of the cost of the abandoned property, plant and equipment. In the first quarter of 2023, upon receipt of the order, the Company reclassified property, plant and equipment to be recovered through securitization to a regulatory asset and such amounts continued to earn a full return until recovered through securitization.

The Securitization Subsidiary issued $341 million aggregate principal amount of the Securitization Bonds on June 29, 2023. See Note 7 for further details of the issuance. The Securitization Subsidiary used a portion of the net proceeds from the issuance to purchase the securitization property from the Company. No gain or loss was recognized.

The Securitization Bonds are secured by the securitization property, which includes the right to recover, through non-bypassable securitization charges payable by the Company’s retail electric customers, the qualified costs of the Company authorized by the IURC order. The Company has no payment obligations with respect to the Securitization Bonds except to remit collections of securitization charges as set forth in a servicing agreement between the Company and the Securitization Subsidiary. The non-bypassable securitization charges are subject to a true-up mechanism.

(6) Transactions with Other Vectren Companies & Affiliates

Support Services and Purchases

Affiliates of CenterPoint Energy provide corporate services to the Company and allocate certain costs to the Company. The costs of services have been charged directly to the Company using methods that management believes are reasonable. These methods include negotiated usage rates, dedicated asset assignment and proportionate corporate formulas based on operating expenses, assets, gross margin, employees and a composite of assets, gross margin and employees. Affiliates of CenterPoint Energy provide certain services to the Company, including geographic services and other miscellaneous services. These services are billed at actual cost, either directly or as an allocation. These 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, 2023 and 2022 are included in Accounts payable - affiliated companies.

Amounts charged for these services are included primarily in Operation and maintenance expenses:

	Year Ended December 31,	
	2023	2022
	(in millions)	
Corporate service charges	$ 41	$ 38

Property, Plant and Equipment

In 2023, the Company purchased certain property, plant and equipment assets from VUH at their net carrying value of $13 million on the date of purchase. In 2022, the Company purchased certain property, plant and equipment assets from CenterPoint Energy at their net carrying value of $8 million on the date of purchase.

Defined Benefit Plans

As of December 31, 2023, 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. Vectren’s current and former employees comprise the vast majority of the participants and retirees covered by these plans. Effective in 2021, certain participants of the Vectren Non-Bargaining Retirement Plan and all liabilities and assets associated with the accrued benefits of such participants were transferred to and became participants of the CenterPoint Energy pension plan.

Vectren satisfies the future funding requirements for its 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 2023 and 2022 to the Company's parents' defined benefit and pension plans. The Company's parent contributed less than $1 million to the CenterPoint

Energy pension plan in 2023 and 2022 for Vectren participants. The Company contributed $1 million in both 2023 and 2022 to Vectren's SERP and post retirement benefit plans. The combined funded status of Vectren's benefit pension plans was approximately 97 percent and 94 percent as of December 31, 2023 and 2022, respectively. The combined funded status of CenterPoint Energy's defined pension plans, excluding Vectren, was approximately 78 percent as of December 31, 2023.

Vectren allocates retirement plan and other postretirement benefit plan periodic cost calculated pursuant to 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 periodic cost being allocated to both operating expense and capital projects. For the years ended December 31, 2023 and 2022, periodic costs totaling $1 million and $3 million, respectively, were charged to the Company from Vectren and CenterPoint Energy.

Any difference between the Company's funding requirements to Vectren and allocated periodic costs is recognized by the Company as an affiliate receivable or payable. The allocation methodology to determine the affiliate funding requirements 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, except for current portions of other postretirement benefit plan obligations which are allocated to individual subsidiaries.

As of December 31, 2023 and 2022, the Company had $15 million and $16 million, respectively, representing defined benefit pension funding by the Company to Vectren that is yet to be reflected in costs. As of December 31, 2023 and 2022, the Company had $16 million and $17 million, respectively, included in Other non-current 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.

Share-Based Incentive Plans and Deferred Compensation Plans

The Company does not have share-based compensation plans separate from Vectren or CenterPoint Energy. As of December 31, 2021 most active employees of the deferred compensation plans were transferred out of VUH and into other CenterPoint Energy companies. As of both December 31, 2023 and 2022, less than $1 million is included in Other non-current liabilities and represents deferred compensation obligations that are yet to be funded in CenterPoint Energy's plan.

Cash Management Arrangements

The Company participates in the centralized cash management program with affiliates of Vectren. As of December 31, 2023 and 2022, the Company had borrowings from the VUH money pool of $50 million and $36 million, respectively, included in Accounts and notes payable - affiliated companies on the Consolidated Balance Sheets. 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 Vectren or CenterPoint Energy. 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 Other non-current liabilities.

ITCs are deferred and amortized to income over the approximate lives of the related property. 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 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. For further information, see Note 5.

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

	Year Ended December 31,	
	2023	**2022**
	(in millions)	
Current:		
Federal	$ 13	$ (9)
State	—	—
Total current tax expense/(benefit)	13	(9)
Deferred:		
Federal	6	27
State	3	9
Total deferred tax expense	9	36
Investment tax credit amortization	(1)	—
Total income tax expense	$ 21	$ 27

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

	Year Ended December 31,	
	2023	**2022**
Statutory rate	21 %	21 %
State & local taxes, net of federal benefit	2	5
Regulatory liability amortization settled through rates	(5)	(3)
Audit Adjustments	5	—
AFUDC Equity	(3)	(1)
All other - net	1	(2)
Effective tax rate	21 %	20 %

Significant components of the net deferred tax liability follow:

	December 31,	
	2023	2022
	(in millions)	
Non-current deferred tax assets:		
Net operating loss & other carryforwards	$ 45	$ 36
Regulatory liabilities settled through future rates	44	45
Employee benefit obligations	4	—
Other – net	7	—
Total deferred tax assets	100	81
Non-current deferred tax liabilities:		
Depreciation & cost recovery timing differences	380	349
Regulatory assets recoverable through future rates	13	9
Employee benefit obligations	—	1
Deferred fuel costs	16	18
Total deferred tax liabilities	409	377
Net deferred tax liability	$ 309	$ 296

As of December 31, 2023, the Company has $27 million investment tax credit carryforward that will expire in 2041. As of December 31, 2023 and 2022, deferred investment tax credits totaling $27 million and $28 million are included in Other non-current liabilities, respectively.

Uncertain Tax Positions

Unrecognized tax benefits for all periods presented were not material to the Company. The Company has no unrecognized tax benefits for the years ended December 31, 2023 and 2022.

Tax Audits and Settlements.

The Company's parent and certain of its subsidiaries file income tax returns in the U.S. federal jurisdiction and various states. Tax years through 2018 and tax year 2021 have been audited and settled with the IRS for CenterPoint Energy. Tax years 2019-2020 remain open. For the 2019-2023 tax years, CenterPoint Energy and its subsidiaries are participants in the IRS's Compliance Assurance Process. Vectren's pre-Merger 2014-2019 tax years have been audited and settled with the IRS.

(7) Borrowing Arrangements & Other Financing Transactions

Long-Term Debt

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

	December 31,	
	2023	2022
	(in millions)	
Fixed Rate Senior Unsecured Notes Payable to Affiliated Companies		
2023, 3.72%	$ —	$ 25
2025, 1.21%	106	106
2028, 3.20%	—	27
2030, 1.72%.	75	75
2032, 3.26%	75	75
2035, 6.10%	—	25
2035, 3.90%	—	17
2043, 4.25%	—	48

	December 31,	
	2023	2022
	(in millions)	
2045, 4.36%	—	16
2047, 3.93%	—	30
2049, 3.42%	—	80
2050, 3.92%	—	100
2055, 4.51%	—	16
2028, 4.67%	—	70
2033, 4.98%	—	70
Total long-term debt payable - affiliated companies	**256**	**780**
Current maturities	—	(25)
Total long-term debt payable - affiliated companies, net	**$ 256**	**$ 755**
First Mortgage Bonds Payable to Third Parties:		
2024, 2013 Series D, 3.50%, tax-exempt	$ 23	$ 23
2025, 2014 Series B, 3.45%, tax-exempt	41	41
2029, 1999 Series, 6.72%	—	80
2037, 2013 Series E, 3.55%, tax-exempt	22	22
2038, 2013 Series A, 4.00%, tax-exempt	22	22
2043, 2013 Series B, 4.00%, tax-exempt	40	40
2044, 2014 Series A, 4.00%, tax exempt	11	22
2055, 2015 Series Mt. Vernon, 4.25%, tax-exempt	23	23
2055, 2015 Series Warrick County, 4.25%, tax-exempt	15	15
2028, 2023 Series A, 4.98%	100	—
2033, 2023 Series A, 5.04%	80	—
2029, 2023 Series B, 5.75%	180	—
2030, 2023 Series B, 5.91%	105	—
2034, 2023 Series B, 6.00%	185	—
Total First Mortgage Bond payable to third parties	**847**	**288**
Current maturities	(23)	(11)
Unamortized debt issuance cost	(3)	—
Total long-term debt payable to third parties, net	**$ 821**	**$ 277**
Securitization Bonds		
2036, 2023 Series-A Securitization Bond Tranche A-1, 5.026%	$ 215	$ —
2041, 2023 Series-A Securitization Bond Tranche A-1, 5.172%	126	—
Total securitization bonds	**341**	—
Current maturities	(17)	—
Unamortized debt issuance cost	(4)	—
Total long-term debt VIE Securitization Bonds, net	**$ 320**	**$ —**

Debt Transactions

Debt Issuances. During 2023, the following debt instruments were issued or incurred:

Issuance Date	Debt Instrument	Aggregate Principal Amount		Interest Rate	Maturity Date
		(in millions, except for interest rates)			
March 2023	First Mortgage Bonds (1)	$	100	4.98%	2028
March 2023	First Mortgage Bonds (1)		80	5.04%	2033
June 2023	Securitization Bonds (2)		341	5.026% - 5.172%	2038-2043
October 2023	First Mortgage Bonds (3)		470	5.75% - 6.00%	2029-2034
		$	991		

(1) Total proceeds from the Company's March 2023 issuances of first mortgage bonds, net of transaction expenses and fees, of approximately $179 million were used for general corporate purposes, including repaying short-term debt.
(2) Total proceeds from the Securitization Subsidiary's June 2023 issuance of Securitization Bonds, net of transaction expenses and fees, of approximately $337 million were used to pay the Company the purchase price of the securitization property. The Company used the net proceeds from the sale of the securitization property (after payment of upfront financing costs) to reimburse or pay for qualified costs approved by the IURC related to the completed retirement of its A.B. Brown 1 and 2 coal-powered generation units. See Notes 2 and 5 for further details.
(3) The Company issued in three tranches: (i) $180 million first mortgage bonds bearing interest at 5.75% due 2029; (ii) $105 million first mortgage bonds bearing interest at 5.91% due 2030; and (iii) $185 million first mortgage bonds bearing interest at 6.00% due 2034. The net proceeds of $467 million were used for general corporate purposes.

Debt Repayments and Redemptions. During 2023, the following debt instruments were repaid at maturity or redeemed prior to maturity:

Repayment/Redemption Date	Debt Instrument	Aggregate Principal		Interest Rate	Maturity Date
		(in millions)			
January 2023	First Mortgage Bonds (1)	$	11	4.00%	2044
December 2023	First Mortgage Bonds (2)		80	6.72%	2029
		$	91		

(1) On December 16, 2022, the Company provided notice of redemption and on January 17, 2023, the Company redeemed $11 million aggregate principal amount of the Company's outstanding first mortgage bonds due 2044 at a redemption price equal to 100% of the principal amount of the first mortgage bonds to be redeemed plus accrued and unpaid interest thereon, if any, to, but excluding, the redemption date.
(2) On November 17, 2023, the Company provided notice of redemption and on December 19, 2023, the Company redeemed $80 million aggregate principal amount of outstanding first mortgage bonds due 2029 at a redemption price equal to the sum of remaining principal and interest payments discounted at the treasury yield plus 10 basis points, plus interest accrued to the redemption date and an applicable make-whole premium.

The Company recorded a loss on early extinguishment of debt of $11 million during the year ended December 31, 2023, which was recorded as a regulatory asset.

Subsequent Event. On March 1, 2024, the Company redeemed $23 million aggregate principal amount of outstanding first mortgage bonds due 2024 at a redemption price equal to the principal amount of the first mortgage bonds to be redeemed plus accrued and unpaid interest thereon.

Securitization Bonds. As of December 31, 2023, the Company had a special purpose subsidiary, the Securitization Subsidiary, which is consolidated. The consolidated special purpose subsidiary is a wholly-owned, bankruptcy remote entity that was formed solely for the purpose of facilitating the securitization financing of qualified costs in the second quarter of 2023 associated with the completed retirement of the A.B. Brown coal generation facilities through the issuance of securitization bonds and activities incidental thereto. The Securitization Bonds are payable only through the imposition of securitization charges payable by the Company's retail electric customers, which are non-bypassable charges to provide recovery of the qualified costs of the Company authorized by the IURC order. The Company has no payment obligations in respect of the Securitization Bonds other than to remit the applicable securitization charges it collects as set forth in servicing agreements among the Company, the Securitization Subsidiary and other parties. The special purpose entity is the sole owner of the right to impose, collect and receive the applicable securitization charges securing the bonds issued. Creditors of the Company have no recourse to any assets or revenues of the Securitization Subsidiary and the bondholders have no recourse to the to the general credit of the Company.

Credit Facilities. The Company had the following revolving credit facility as of December 31, 2023:

Execution Date	Size of Facility (in millions)		Draw Rate of SOFR plus (1)	Financial Covenant Limit on Debt for Borrowed Money to Capital Ratio	Debt for Borrowed Money to Capital Ratio as of December 31, 2023 (2)	Termination Date
December 6, 2022	$	250	1.125%	65%	46.5%	December 6, 2027

(1) Based on credit ratings as of December 31, 2023.
(2) As defined in the revolving credit facility agreement, excluding Securitization Bonds.

There were no borrowings outstanding under the revolving credit facility as of December 31, 2023.

Mandatory Tenders. In April 2023, the Company executed a remarketing agreement, subject to standard conditions precedent, to remarket five series of tax-exempt debt issued by the Indiana Finance Authority, and secured by first mortgage bonds, of approximately $148 million, comprised of: (i) $107 million aggregate principal amount of Environmental Improvement Refunding Revenue Bonds, Series 2013, originally issued by the Indiana Finance Authority on April 26, 2013, and (ii) $41 million aggregate principal amount of Environmental Improvement Refunding Revenue Bonds, Series 2014, originally issued by the Indiana Finance Authority on September 24, 2014, which closed on May 1, 2023.

In July 2023, the Company executed a remarketing agreement to remarket two series of tax-exempt debt issued by the City of Mount Vernon, Indiana and Warrick County, Indiana, and secured by first mortgage bonds, 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 and (ii) $15 million aggregate principal amount of Environmental Improvement Revenue Bonds, Series 2015 issued by Warrick County, which closed on September 1, 2023. Effective September 1, 2023, the bonds of each series bear interest at a fixed rate of 4.250% per annum to the earlier of (i) its redemption date or (ii) September 1, 2028, at which time the bonds are subject to mandatory tender.

Future Long-Term Debt Sinking Fund Requirements and Maturities. As of December 31, 2023, the Company had approximately $847 million aggregate principal amount of first mortgage bonds outstanding. Generally, all of the Company's real and tangible property is subject to the lien of its mortgage indenture, which was amended and restated effective as of January 1, 2023. As of December 31, 2023, the Company was permitted to issue additional bonds under its mortgage indenture up to 70% of then unfunded property additions and approximately $966 million of additional first mortgage bonds could be issued on this basis.

Maturities. As of December 31, 2023, maturities of long-term debt, excluding discounts, premiums and issuance costs, , were as follows:

	Affiliate Debt		Third Party Debt		Securitization Bonds		Total Debt	
	(in millions)							
2024	$	—	$	23	$	17	$	40
2025		106		41		13		160
2026		—		—		14		14
2027		—		—		14		14
2028		—		100		15		115
2029 and thereafter		150		683		268		1,101

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, 2023, the Company was in compliance with all financial debt covenants.

(8) Commitments & Contingencies

(a) Purchase Obligations

Commitments include minimum purchase obligations related to the Company's Natural Gas reportable segment and Electric reportable segment. A purchase obligation is defined as an agreement to purchase goods or services that is enforceable and legally binding on the Company and that specifies all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transaction. Contracts with minimum payment provisions have various quantity requirements and durations and are not classified as non-trading derivative assets and liabilities in the Company's Balance Sheets as of December 31, 2023 and 2022. These contracts meet an exception as "normal purchases contracts" or do not meet the definition of a derivative. Natural gas and coal supply commitments also include transportation contracts that do not meet the definition of a derivative.

On February 1, 2023, the Company entered into an amended and restated BTA to purchase the 191 MW Posey Solar project for a fixed purchase price over the anticipated 35-year life. On February 7, 2023, the Company filed a CPCN with the IURC to approve the amended BTA. With the passage of the IRA, the Company can now pursue PTCs for solar projects. The Company filed the updated CPCN with a request that project costs, net of PTCs, be recovered in rate base, through base rates or the CECA mechanism, depending on which provides more timely recovery. On September 6, 2023, the IURC issued an order approving the CPCN. The Posey Solar project is expected to be placed in service in 2025.

On January 11, 2023, the IURC issued an order approving the settlement agreement granting the Company a CPCN to purchase and acquire the 130 MW Pike County solar project through a BTA and approved the estimated cost. The IURC also designated the project as a clean energy project as well as approved the proposed levelized rate and associated ratemaking and accounting treatment. Due to inflationary pressures, the developer disclosed that costs have exceeded the agreed upon levels in the BTA. After negotiations, the Company and the developer were not able to agree upon updated pricing. As a result, on February 27, 2024, the Company provided notice that it was exercising its right to terminate the BTA, which terminated all further obligations of the Company with respect to the project.

As of December 31, 2023, minimum purchase obligations were approximately:

	Natural Gas Supply	Electric Supply (1)
	(in millions)	
2024	$ 6	$ 145
2025	4	478
2026	4	342
2027	4	105
2028	3	68
2029 and beyond	22	737

(1) Primarily the Company's undiscounted minimum payment obligations related to PPAs with commitments ranging from 15 to 25 years and its purchase commitment under its BTA in Posey County, Indiana at the original contracted amount, prior to any renegotiation, and its BTA in Pike County, Indiana, prior to its termination in February 2024, are included above.

Excluded from the table above are estimates for cash outlays from other PPAs through CEI South that do not have minimum thresholds but do require payment when energy is generated by the provider. Costs arising from certain of these commitments are pass-through costs, generally collected dollar-for-dollar from retail customers through regulator-approved cost recovery mechanisms.

For further details about the Company's BTAs and PPAs, see Note 9.

(b) AMAs

The Company entered into a third-party AMA beginning in April 2021 through March 2024 associated with its utility distribution service in Indiana. Pursuant to the provisions of the agreement, the Company either sells natural gas to the asset manager and agrees to repurchase an equivalent amount of natural gas throughout the year at the same cost, or simply purchases its full natural gas requirements at each delivery point from the asset manager. Generally, AMAs are contracts between the Company and an asset manager that are intended to transfer the working capital obligation and maximize the utilization of the assets. In these agreements, the Company agrees to release transportation and storage capacity to other parties to manage natural gas storage, supply and delivery arrangements for the Company and to use the released capacity for other purposes when it is not needed for the Company. The Company may receive compensation from the asset manager through payments made over the life of the AMAs. The Company has an obligation to purchase its winter storage requirements that have been released to the asset manager under these AMAs.

(c) Environmental and Other Matters

MGP Sites. The Company and its predecessors operated MGPs in the past. The costs the Company expects to incur to fulfill its obligations are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments and inflation factors, among others. While the Company has recorded obligations for all costs which are probable and estimable, including amounts it is presently 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 PRP or insurance recovery.

Indiana MGPs. The Company has identified its involvement in 5 manufactured gas plant sites in the Company'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.

Total costs that may be incurred in connection with addressing these sites cannot be determined at this time. The estimated accrued costs are limited to the Company's share of the remediation efforts and are therefore net of exposures of other PRPs. The estimated range of possible remediation costs for the sites for which the Company believes it may have responsibility was based on remediation continuing for the minimum time frame given in the table below.

	December 31, 2023	
	(in millions, except years)	
Amount accrued for remediation	$	2
Minimum estimated remediation costs		1
Maximum estimated remediation costs		8
Minimum years of remediation		5
Maximum years of remediation		20

The cost estimates are based on studies of a site or industry average costs for remediation of sites of similar size. The actual remediation costs will depend on the number of sites to be remediated, the participation of other PRPs, if any, and the remediation methods used.

The Company does not expect the ultimate outcome of these matters to have a material adverse effect on its financial condition, results of operations or cash flows.

CCR Rule. In April 2015, the EPA finalized its CCR Rule, which regulates ash as non-hazardous material under the 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. In July 2018, the EPA released its final CCR Rule Phase I Reconsideration which extended the deadline to October 31, 2020 for ceasing placement of ash in ponds that exceed groundwater protections standards or that fail to meet location restrictions. In August 2019, the EPA proposed additional “Part A” amendments to its CCR Rule with respect to beneficial reuse of ash and other materials. The Part A amendments were finalized in August 2020 and extended the deadline to cease placement of ash in ponds to April 11, 2021, discussed further below. The Part A amendments do not restrict the Company's current beneficial reuse of its fly ash. On May 18, 2023, the EPA issued a proposed revision to the CCR rule that could potentially expand the scope of units regulated under the federal CCR rule (the CCR “Legacy” rule). The CCR Legacy rule seeks to include legacy CCR surface impoundments (inactive surface impoundments at inactive generating facilities) as well as new “CCR management units” at active or inactive facilities otherwise subject to federal CCR regulations. The potential impact of the CCR Legacy rule is uncertain at this time, and if finalized could require the Company to conduct additional CCR investigations.

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 were necessary to determine the remaining service life of the ponds and whether a pond must be retrofitted with liners or closed in place. 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. Groundwater monitoring indicates potential groundwater impacts adjacent 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 was required to cease disposal of new ash in the ponds and commence closure of the ponds by April 11, 2021, unless approved for an extension. The Company filed timely extension requests available under the CCR Rule that would allow the Company to continue to use the ponds through October 15, 2023. On October 5, 2022, EPA issued a proposed conditional approval of the Part A extension request for the A.B. Brown pond. Both the Culley East and A.B. Brown facility have been taken out of service in a timely manner per the commitments made to the EPA in the extension requests filed for both ponds. 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 has already completed closure activities. On August 14, 2019, the Company filed its petition with the IURC for recovery of costs associated with the closure of the A.B. Brown ash pond, which would include costs associated with the excavation and recycling of ponded ash. This petition was subsequently approved by the IURC on May 13, 2020. On October 28, 2020, the IURC approved the Company'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. On November 1, 2022, the Company filed for a CPCN to recover federally mandated costs associated with closure of the Culley East Pond, its third and final ash pond. The Company is also seeking accounting and ratemaking relief for the project, and on June 8, 2023, the Company filed a revised CPCN for recovery of the federally mandated ash pond costs. The project costs are estimated to be approximately \$52 million, inclusive of overheads.

As of December 31, 2023, the Company has recorded an approximate \$116 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 AROs, the Company also anticipates equipment purchases of between \$60 million and \$80 million to complete the A.B. Brown closure project.

Clean Water Act Permitting of Groundwater Discharges. In April 2020, the U.S. Supreme Court issued an opinion providing that indirect discharges via groundwater or other non-point sources are subject to permitting and liability under the Clean Water Act when they are the functional equivalent of a direct discharge. On November 27, 2023, the EPA published draft guidance regarding the application of the "functional equivalent" analysis as related to permitting of certain discharges through groundwater to surface waters. The Company is evaluating the extent to which this decision and the proposed EPA guidance will affect Clean Water Act permitting requirements and/or liability for its operations.

Other Environmental. From time to time, the Company identifies the presence of environmental contaminants during operations or on property where predecessors have conducted operations. Other such sites involving contaminants may be identified in the future. The Company has and expects to continue to remediate any identified sites consistent with state and federal legal obligations. From time to time, the Company has received notices, and may receive notices in the future, from regulatory authorities or others regarding status as a PRP in connection with sites found to require remediation due to the presence of environmental contaminants. In addition, the Company has been, or may be, named from time to time as a defendant in litigation related to such sites. Although the ultimate outcome of such matters cannot be predicted at this time, the Company does not expect these matters, either individually or in the aggregate, to have a material adverse effect on its financial condition, results of operations or cash flows.

Other Proceedings

The Company is involved in other legal, environmental, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business. From time to time, the Company is also a defendant in legal proceedings with respect to claims brought by various plaintiffs against broad groups of participants in the energy industry. Some of these proceedings involve substantial amounts. The Company regularly analyzes current information and, as necessary, provides accruals for probable and reasonably estimable liabilities on the eventual disposition of these matters. The Company does not expect the disposition of these matters to have a material adverse effect on its financial condition, results of operations or cash flows.

(9) Regulatory Matters

Securitization of Generation Retirements

For further information about the issuance of Securitization Bonds, see Note 5 to the consolidated financial statements.

CEI South CPCN

BTAs

On February 23, 2021, the Company filed a CPCN with the IURC seeking approval to purchase the Posey solar project. On October 27, 2021, the IURC issued an order approving the CPCN, authorizing the Company to purchase the Posey solar project through a BTA to acquire its solar array assets for a fixed purchase price and approved recovery of costs via a levelized rate over the anticipated 35-year life. Due to community feedback and rising project costs caused by inflation and supply chain issues affecting the energy industry, the Company, along with Arevon, the developer, announced plans in January 2022 to downsize the Posey solar project to 191 MW. The Company collaboratively agreed to the scope change, and on February 1, 2023, the Company entered into an amended and restated BTA that is contingent on further IURC review and approval. On February 7, 2023, the Company filed a CPCN with the IURC to approve the amended BTA. With the passage of the IRA, the Company can now pursue PTCs for solar projects. The Company requested that project costs, net of PTCs, be recovered in rate base rather than a levelized rate, through base rates or the CECA mechanism, depending on which provides more timely recovery. On September 6, 2023 the IURC issued an order approving the CPCN. The Posey solar project is expected to be placed in service in 2025 and recovered through base rates.

On July 5, 2022, the Company entered into a BTA to acquire a 130 MW solar array in Pike County, Indiana through a special purpose entity for a capped purchase price. A CPCN for the project was filed with the IURC on July 29, 2022. On September 21, 2022, an agreement in principle was reached resolving all the issues between the Company and OUCC. The Stipulation and Settlement agreement was filed on October 6, 2022 and a settlement hearing was held on November 1, 2022. On January 11, 2023, the IURC issued an order approving the settlement agreement authorizing the Company to purchase and acquire the Pike County solar project through a BTA and approved the estimated cost. The IURC also designated the project as a clean energy project under Ind. Code Ch. 8-1-8.8, approved the proposed levelized rate and associated ratemaking and accounting treatment. Due to inflationary pressures, the developer disclosed that costs have exceeded the agreed upon levels in the BTA. After negotiations, the Company and the developer were not able to agree upon updated pricing. As a result, on February 27, 2024, the Company provided notice that it was exercising its right to terminate the BTA, which terminated all further obligations of the Company with respect to the project.

On January 10, 2023, the Company filed a CPCN with the IURC to acquire a wind energy generating facility with installed capacity of 200 MWs through a BTA, consistent with its 2019/2020 IRP that calls for up to 300 MWs of wind generation. The wind project is located in MISO's Central Region. The Company has approval to recover the costs of the wind facility via the CECA mechanism, which is expected to be placed in service by the end of 2026. On June 6, 2023 the IURC issued an order approving the CPCN, and thereby authorizing the Company to purchase the wind generating facility. However, as of the date of these financial statements, the Company has not entered into any definitive agreement relating to this wind energy generating facility, and it is not certain that a definitive agreement will be entered into at all.

PPAs

The Company also sought approval in February 2021 for a 100 MW solar PPA with Clenera LLC in Warrick County, Indiana. The request accounted for increased cost of debt related to this PPA, which provides equivalent equity return to offset imputed debt during the 25 year life of the PPA. In October 2021, the IURC approved the Warrick County solar PPA but denied the request to preemptively offset imputed debt in the PPA cost. Due to rising project costs caused by inflation and supply chain issues affecting the energy industry, Clenera and the Company were compelled to renegotiate terms of the agreement to increase the PPA price. On January 17, 2023, the Company filed a request with the IURC to amend the previously approved PPA with certain modifications. Revised purchase power costs are requested to be recovered through the fuel adjustment clause proceedings over the term of the amended PPA. On May 30, 2023, the IURC approved the Warrick County solar amended PPA; however, due to MISO interconnection study delays, the developer disclosed the project in-service date could be delayed from 2025 to 2026.

On August 25, 2021, the Company filed with the IURC seeking approval to purchase 185 MW of solar power, under a 15-year PPA, from Oriden, which is developing a solar project in Vermillion County, Indiana, and 150 MW of solar power, under a 20-year PPA, from Origis, which is developing a solar project in Knox County, Indiana. On May 4, 2022, the IURC issued an order approving the Company to enter into both PPAs. In March 2022, when the results of the MISO interconnection study were completed, Origis advised the Company that the costs to construct the solar project in Knox County, Indiana had increased. The increase was largely driven by escalating commodity and supply chain costs impacting manufacturers worldwide. In August 2022, the Company and Origis entered into an amended PPA, which reiterated the terms contained in the 2021 PPA with certain modifications. On February 22, 2023 the IURC approved the Knox County solar amended PPA; however, due to MISO interconnection delays, the project in-service date could be delayed from 2024 to 2025. On January 17, 2023, the Company filed a request with the IURC to amend the previously approved PPA with Oriden with certain modifications. Revised purchase power costs were approved to be recovered through the fuel adjustment clause proceedings over the term of the amended PPA with Oriden. On May 30, 2023, the IURC approved the Vermillion County solar amended PPA; however, due to MISO interconnection study delays, the developer disclosed the project in-service date could be delayed from 2025 to 2026.

Natural Gas Combustion Turbines

On June 17, 2021, the Company filed a CPCN with the IURC seeking approval to construct two natural gas combustion turbines to replace portions of its existing coal-fired generation fleet. On June 28, 2022, the IURC approved the CPCN. The estimated $334 million turbine facility is being constructed at the previous site of the A.B. Brown power plant in Posey County, Indiana and will provide a combined output of 460 MW. The Company received approval for depreciation expense and post in-service carrying costs to be deferred in a regulatory asset until the date the Company's base rates include a return on and recovery of depreciation expense on the facility. A new approximately 23.5 mile pipeline will be constructed and operated by Texas Gas Transmission, LLC to supply natural gas to the turbine facility. FERC granted a certificate to construct the pipeline on October 20, 2022. The period to challenge FERC’s certificate in a federal district court expired on February 20, 2023. The Company granted its contractor a full notice to proceed to construct the turbines on December 9, 2022. The facility is targeted to be operational by mid year 2025. Recovery of the proposed natural gas combustion turbines and regulatory asset is included in the forecasted test year in the Company's rate case, which was filed with the IURC on December 5, 2023.

Culley Unit 3 Operations

In June 2022, F.B. Culley Unit 3, the Company's coal-fired electric generation unit with an installed generating capacity of 270 MW, experienced an operating issue relating to its boiler feed pump turbine. The unit returned to service in March 2023. In testimony filed September 13, 2023, the OUCC and an intervenor that represents industrial customers filed testimony with the IURC alleging that the Company did not act prudently which led to the unplanned outage and recommended disallowances between $21 million to $27 million. On October 23, 2023, the Company filed rebuttal testimony with the IURC and an evidentiary hearing was held on November 2, 2023. The Company expects a decision from the IURC in the first half of 2024.

Solar Panel Issues

The Company's current and future solar projects have been impacted by delays and/or increased costs. The potential delays and inflationary cost pressures communicated from the developers of our solar projects have been primarily due to (i) unavailability of solar panels and other uncertainties related to a DOC investigation on anti-dumping and countervailing duties petition filed by a domestic solar manufacturer, (ii) the December 2021 Uyghur Forced Labor Prevention Act on solar modules and other products manufactured in China's Xinjiang Uyghur Autonomous Region and (iii) persistent general global supply chain and labor availability issues. On December 2, 2022, the DOC issued its preliminary determination, finding four of the eight companies being investigated are attempting to bypass U.S. duties. On August 18, 2023, the DOC announced its final determination and found that five of the eight companies investigated are attempting to bypass U.S. duties by doing minor processing in one of the Southeast Asian countries before shipment to the United States. Pursuant to President Biden’s executive order issued in June 2022, duties will not be collected on any solar module and cell imports from these Southeast Asian countries until June 2024, as long as the imports are consumed in the U.S. market within six months of the termination of the executive order. The executive order could be subject to legal challenges and its effects remain uncertain. The resolution of these issues will determine what additional costs or delays our solar projects will be subject to. These impacts have resulted in cost increases for certain projects, and may result in cost increases in other projects, and such impacts have resulted in, or are expected to result in, the need for us to seek additional regulatory review and approvals. Additionally, significant changes to project costs and schedules as a result of these factors could impact the viability of the projects.

TDSIC 2.0

On May 24, 2023, the Company filed its petition and case-in-chief with the IURC requesting, among other things, approval of its five-year plan for transmission, distribution, and storage improvements pursuant to Ind. Code ch. 8-1-39 ("TDSIC Plan"). Intervenors filed their case-in-chief on August 16, 2023 and the Company filed rebuttal on August 29, 2023. A hearing was held on September 13, 2023 and an order approving the TDSIC Plan was issued on December 27, 2023. The approved five-year TDSIC Plan, covering the period January 1, 2024 through December 31, 2028, consists of approximately $454 million in proposed investments across seven different programs: (1) Distribution 12kV Circuit Rebuild, (2) Distribution Underground Rebuild, (3) Distribution Automation, (4) Wood pole replacement, (5) Transmission Line Rebuild, (6) Substation Rebuild, and (7) Substation Physical Security.

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 in Indiana to adjust its capital tracking mechanisms (CSIA for gas and TDSIC, ECA and CECA for electric) and its energy efficiency cost tracker (DSMA for electric).

Rate Case. On December 5, 2023, the Company filed a petition with the IURC for authority to modify its rates and charges for electric utility service through a phase-in of rates. The requested increase is approximately 16% or $119 million based on a forward looking 2025 test year. The need for a rate increase is primarily driven by the continuing investment that is being made to ensure the safety and reliability of the system and normal increases in operating expenses. The rate case reflects a proposed 10.4% ROE on a 55% equity ratio. A hearing is scheduled for late-April through mid-May 2024. A final order is expected in the fourth quarter of 2024.

The table below reflects significant applications pending or completed since the Company's 2022 financial statements were furnished to the SEC on Current Report 8-K dated March 7, 2023 through March 8, 2024.

Mechanism	Annual Increase (Decrease) (1) (in millions of dollars)	Filing Date	Effective Date	Approval Date	Additional Information
			Gas (IURC)		
CSIA	3	April 2023	July 2023	July 2023	Requested an increase of $33 million to rate base, which reflects approximately $3 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 a change in (over)/under-recovery variance of $1 million annually. Also included are unrecovered deferred operations and maintenance expenses of $9 million. OUCC filed on June 2, 2023, recommending approval of the proposed CSIA rates and updated plan as filed, with non-cost recommendations. Rebuttal testimony filed June 16, 2023. A hearing was held June 28, 2023. The IURC issued an Order approving the CSIA on July 26, 2023.
CSIA	3	October 2023	February 2024	January 2024	Requested an increase of $31 million to rate base, which reflects approximately $3 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 a change in (over)/under-recovery variance of $1 million annually. OUCC filed on December 8, 2023, recommending disallowance of two projects for customer-side replacements. Engineering rebuttal testimony was filed December 15, 2023, stating why costs were necessary for safety and integrity of customers and system. Responded to IURC docket entry requesting additional information on January 2, 2024. A hearing was held January 3, 2024. The IURC issued an order on January 31, 2024, approving the CSIA with the exception of the two projects for customer-side replacements which are not authorized for recovery. CEI South filed revised revenue requirement schedules removing the two project costs with its compliance filing. Revised rates were effective February 1, 2024.
			Electric (IURC)		
TDSIC	2	February 2023	June 2023	May 2023	Requested an increase of $31 million to rate base, which reflects a $5 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 and a tax reform credit for a total of ($1 million). OUCC filed on April 3, 2023, recommending approval of the proposed TDSIC rates and updated plan as filed. A hearing was held on May 3, 2023. On May 30, 2023, the IURC issued an order approving the TDSIC rates an updated plan as filed with rates effective June 1, 2023.
CECA	—	February 2023	June 2023	May 2023	Requested an increase of less than $1 million to rate base, which reflects an annual increase of less than $1 million in current revenues. The mechanism also includes a change in (over)/under-recovery variance of less than ($1 million). OUCC filed on March 31, 2023, recommending approval of the proposed CECA cost recovery with a reduction of approximately $0.3 million. Rebuttal testimony was filed on April 6, 2023. A hearing was held on May 3, 2023. On May 30, 2023, the IURC issued an order approving the CECA rates with a cost recovery reduction of approximately $0.3 million with rates effective June 6, 2023.
ECA	1	May 2023	February 2024	February 2024	Requested an increase of $51 million to rate base, which reflects a $1 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 less than $1 million. A hearing was held on October 24, 2023. CEI South filed a proposed order on October 31, 2023. The OUCC filed a proposed order on November 8, 2023. CEI South filed a response to the OUCC proposed order on November 15, 2023. A final order was issued February 7, 2024 with rates effective February 8, 2024.

Mechanism	Annual Increase (Decrease) (1) (in millions of dollars)	Filing Date	Effective Date	Approval Date	Additional Information
DSMA	16	July 2023	January 2024	November 2023	The requested $45 million is comprised primarily of the following: 2024 program costs of $11 million and $26 million of lost revenue, $3 million related to the over-recovery of 2022 program costs and $11 million under-recovery related to a prior period variance adjustment; the requested $45 million is an increase of $16 million compared to the prior DSMA. A settlement between CEI South and the OUCC was reached concerning the $11 million under-recovery which resolves all issues related to the DSMA for January through December 2024 including the $11 million under-recovery. The settlement provides that the IURC should approve the DSMA and that CEI South will arrange for educational training on demand side management offerings. A settlement hearing was held on October 24, 2023. The IURC issued an Order approving the settlement on November 22, 2023, with rates effective January 1, 2024.
TDSIC	3	August 2023	November 2023	November 2023	Requested an increase of $27 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 and a tax reform credit for a total of ($0.2 million). OUCC filed on October 2, 2023 recommending approval of the proposed TDSIC rates. A hearing was held on October 31, 2023. The IURC issued an Order approving the TDSIC on November 29, 2023, with rates effective November 30, 2023.
Rate Case (1)	119	December 2023	TBD	TBD	See discussion above under *Rate Case.*
TDSIC(1)	5	February 2024	TBD	TBD	Requested an increase of $36 million to rate base, which reflects a $5 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 and a tax reform credit for a total of ($1 million). OUCC is expected to file testimony on April 2, 2024 and a hearing is scheduled for April 30, 2024.
CECA (1)	—	February 2024	TBD	TBD	Requested a decrease of $1 million to rate base, which reflects no change in current revenues. The mechanism also includes a change in (over)/under-recovery variance of $0.1 million.

(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

IRA

On August 16, 2022, the IRA was signed into law. The new law extends or creates tax-related energy incentives for solar, wind and alternative clean energy sources, implements, subject to certain exceptions, a 1% tax on share repurchases after December 31, 2022, and implements a 15% CAMT based on the adjusted financial statement income of certain large corporations. Corporations are entitled to a CAMT credit to the extent CAMT liability exceeds regular tax liability, which can be carried forward indefinitely and used in future years when regular tax exceeds the CAMT. The IRA did not have a material impact on the Company's 2023 financial results. It is likely that the Company will owe CAMT in excess of its regular tax liability beginning in 2024. As a result, the Company expects a temporary increase in federal cash tax payments due to this provision.

Greenhouse Gas Regulation and Compliance

There is increasing attention being paid in the United States and worldwide to the issue of climate change. As a result, from time to time, regulatory agencies have considered the modification of existing laws or regulations or the adoption of new laws or regulations addressing the emissions of GHG on the state, federal, or international level. On August 3, 2015, the EPA released its CPP rule, which required a 32% 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. On July 8, 2019, the EPA published the ACE rule, which (i) repealed the CPP rule; (ii) replaced the CPP rule with a program that requires states to implement a program of energy efficiency improvement targets for individual coal-fired electric generating units; and (iii) amended the implementing regulations for Section 111(d) of the Clean Air Act. On January 19, 2021, the majority of the ACE rule — including the CPP repeal, CPP replacement, and the timing-related portions of the Section 111(d) implementing rule — was struck down by the U.S. Court of Appeals for the D.C. Circuit and on October 29, 2021, the U.S. Supreme Court agreed to consider four petitions filed by various coal interests and a coalition of 19 states. On June 30, 2022, the U.S. Supreme Court ruled that the EPA exceeded its authority in promulgating the CPP. On May 11, 2023, the EPA announced proposed emission limits and guidelines for carbon dioxide from fossil fuel-fired power plants under Section 111 of the Clean Air Act which, if finalized, apply new GHG performance standards for those existing coal-fired units expected to continue operation beyond December 31, 2029. We will continue to evaluate the applicability of the rule to existing and new gas-fired generating units, but would note that the Company does not currently have plans to operate any of its coal-fired units beyond December 2029.

The Biden administration recommitted the United States to the Paris Agreement, which has driven a renewed regulatory push to require further GHG emission reductions from the energy sector and proceeded to lead negotiations at the global climate conference in Glasgow, Scotland. On April 22, 2021, President Biden announced new goals of 50% reduction of economy-wide GHG emissions, and 100% carbon-free electricity by 2035, which formed the basis of the U.S. commitments announced in Glasgow. In September 2021, CenterPoint Energy announced its net zero emissions goals for both Scope 1 emissions and certain Scope 2 emissions by 2035 as well as a goal to reduce certain Scope 3 emissions by 20% to 30% by 2035. CenterPoint Energy's Scope 2 estimates exclude emissions related to purchased power in Indiana between 2024 and 2026 as estimated. CenterPoint Energy's Scope 3 emissions estimates are based on the total natural gas supply delivered to residential and commercial customers as reported in the EIA Form EIA-176 reports and do not take into account the emissions of transport customers and emissions related to upstream extraction. CenterPoint Energy's net zero emissions goals are aligned with the Company's generation transition plan and are expected to position the Company to comply with anticipated future regulatory requirements related to GHG emissions reductions. The Company’s revenues, operating costs and capital requirements could be adversely affected as a result of any regulatory action that would require installation of new control technologies or a modification of its operations or would have the effect of reducing the consumption of natural gas. The IRA established the Methane Emissions Reduction Program, which imposes a charge on methane emissions from certain natural gas transmission facilities, and the EPA has proposed new regulations targeting reductions in methane emissions, which if implemented will increase costs related to production, transmission and storage of natural gas. Incentives to conserve energy or to use energy sources other than natural gas could result in a decrease in demand for the Company’s services. Further, certain local government bodies have introduced or are considering requirements and/or incentives to reduce energy consumption by certain specified dates. These initiatives could have a significant impact on the Company and its operations, and this impact could increase if other cities and jurisdictions in its service area enact similar initiatives. Further, our third party suppliers, vendors and partners may also be impacted by climate change laws and regulations, which could impact the Company’s business by, among other things, causing permitting and construction delays, project cancellations or increased project costs passed on to the Company. Conversely, regulatory actions that effectively promote the consumption of natural gas because of its lower emissions characteristics would be expected to benefit the Company. At this time, however, the Company cannot quantify the magnitude of the impacts from possible new regulatory actions related to GHG emissions, either positive or negative, on the Company’s business.

Compliance costs and other effects associated with climate change, reductions in GHG emissions and obtaining renewable energy sources remain uncertain. Although the amount of compliance costs remains uncertain, any new regulation or legislation relating to climate change will likely result in an increase in compliance costs. While the requirements of a federal or state rule remain uncertain, the Company will continue to monitor regulatory activity regarding GHG emission standards that may affect its business. Currently, the Company does not purchase carbon credits. In connection with its net zero emissions goals, the Company is expected to purchase carbon credits in the future; however, the Company does not currently expect the number of credits, or cost for those credits, to be material.

Climate Change Trends and Uncertainties

As a result of increased awareness regarding climate change, coupled with adverse economic conditions, availability of alternative energy sources, including private solar, microturbines, fuel cells, energy-efficient buildings and energy storage devices, and new regulations restricting emissions, including potential regulations of methane emissions, some consumers and companies may use less energy, meet their own energy needs through alternative energy sources or avoid expansions of their facilities, including natural gas facilities, resulting in less demand for the Company's services. As these technologies become a more cost-competitive option over time, whether through cost effectiveness or government incentives and subsidies, certain customers may choose to meet their own energy needs and subsequently decrease usage of the Company's systems and services, which may result in, among other things, the Company's generating facilities becoming less competitive and economical. Further, evolving investor sentiment related to the use of fossil fuels and initiatives to restrict continued production of fossil fuels have had significant impacts on the Company's electric generation and natural gas businesses. For example, because the Company's current generating facilities substantially rely on coal for their operations, certain financial institutions choose not to participate in the Company's financing arrangements. Conversely, demand for the Company's services may increase as a result of customer changes in response to climate change. For example, as the utilization of electric vehicles increases, demand for electricity may increase, resulting in increased usage of the Company's systems and services. Any negative opinions with respect to the Company's environmental practices or its ability to meet the challenges posed by climate change formed by regulators, customers, legislators or other stakeholders could harm its reputation.

To address these developments, CenterPoint Energy announced its net zero emissions goals for both Scope 1 emissions and certain Scope 2 emissions by 2035. The Company's 2019/2020 IRP identified a preferred portfolio that retires 730 MW of coal-fired generation facilities and replaces these resources with a mix of generating resources composed primarily of renewables, including solar, wind, and solar with storage, supported by dispatchable natural gas combustion turbines including a pipeline to serve such natural gas generation. The Company continues to execute on its 2019/2020 IRP and has received initial approvals for 756 MWs of the 700-1,000 MWs identified within its 2019/2020 IRP. The Company believes its planned investments in renewable energy generation and corresponding planned reduction in its GHG emissions as part of its net zero emissions goals support global efforts to reduce the impacts of climate change. The Company has conducted a new IRP, which was submitted to the IURC in May 2023, to identify an appropriate generation resource portfolio to satisfy the needs of its customers and comply with environmental regulations. The proposed preferred portfolio is the second evolution to the generation transition plan to move away from coal-fired generation to a more sustainable portfolio of resources. The Company plans to convert its last remaining coal unit to natural gas by 2027 and to add a significant amount of additional renewable resources through 2033.

To the extent climate changes result in warmer temperatures in the Company’s service territory, financial results from its business could be adversely impacted. For example, the Company could be adversely affected through lower natural gas sales. Another possible result of climate change is more frequent and more severe weather events, such as hurricanes, tornadoes and flooding, including such storms as the February 2021 Winter Storm Event. To the extent adverse weather conditions affect the Company’s suppliers, results from its natural gas business may suffer. When the Company cannot deliver electricity or natural gas to customers, or customers cannot receive services, the Company’s financial results can be impacted by lost revenues, and it generally must seek approval from regulators to recover restoration costs. To the extent the Company is unable to recover those costs, or if higher rates resulting from recovery of such costs result in reduced demand for services, the Company’s future financial results may be adversely impacted. Further, as the intensity and frequency of significant weather events continues, it may impact the Company’s ability to secure cost-efficient insurance.

ELG

In 2015, the EPA finalized revisions to the existing steam electric wastewater discharge standards which set more stringent wastewater discharge limits and effectively prohibited further wet disposal of coal ash in ash ponds. These new standards are applied at the time of permit renewal and an affected facility must comply with the wastewater discharge limitations no later than December 31, 2023, and the prohibition of wet sluicing of bottom ash no later than December 31, 2025. In February 2019, the IURC approved the Company's ELG compliance plan for its F.B. Culley Generating Station, which was completed in a timely manner and in compliance with the requirements of ELG.

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, the EPA finalized a regulation requiring installation of “best technology available” to mitigate impingement and entrainment of aquatic species in cooling water intake structures. The Company is currently completing the required ecological studies and anticipates timely compliance in 2025.

(11) Fair Value Measurements

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

	December 31,			
	2023		2022	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Assets	(in millions)			
Natural gas derivatives (1)	$ —	$ —	$ 2	$ 2
Interest rate derivatives (2)	—	—	1	1
Total assets	$ —	$ —	$ 3	$ 3
Liabilities				
Long-term debt payable to third parties	$ 844	$ 979	$ 288	$ 273
Long-term debt payable - affiliated companies	256	227	755	636
Long-term debt VIE securitization bonds	337	337	—	—
Natural gas derivatives (3)	2	2	—	—
Total liabilities	$ 1,439	$ 1,545	$ 1,043	$ 909

(1) Presented in Other non-current assets on the Consolidated Balance Sheets.
(2) Presented in Prepaid expenses and other current assets on the Consolidated Balance Sheets.
(3) Presented in Accrued liabilities on the Consolidated Balance Sheets.

Certain of the Company's derivative instruments 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 derivative instruments could request immediate payment.

	As of December 31,	
	2023	2022
	(in millions)	
Aggregate fair value of derivatives with credit-risk-related contingent features in a liability position	$ 1	$ —
Fair value of collateral already posted	—	—
Additional collateral required to be posted if credit risk contingent features triggered (1)	1	—

(1) The maximum collateral required if further escalating collateral is triggered would equal the net liability position.

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.

(12) Segment Reporting

The Company’s determination of reportable segments considers the strategic operating units under which its CODM manages sales, allocates resources and assesses performance of various products and services to wholesale or retail customers in differing regulatory environments. The Company's CODM views net income as the measure of profit or loss for the reportable segments.

As of December 31, 2023, 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:

	Revenues from External Customers	Depreciation and Amortization	Net Income
		(in millions)	
For the year ended December 31, 2023:			
Natural Gas	$ 128	$ 21	$ 21
Electric (1)	612	125	59
Total	$ 740	$ 146	$ 80
For the year ended December 31, 2022:			
Natural Gas	$ 146	$ 19	$ 19
Electric	696	125	90
Total	$ 842	$ 144	$ 109

(1) Includes revenues and amortization expense related to the Securitization subsidiary reflected on the Company's Consolidated Statements of Income.

	Year Ended December 31,	
	2023	2022
	(in millions)	
Capital Expenditures		
Natural Gas	$ 132	$ 86
Electric	360	315
Non-cash costs & changes in accruals	3	(38)
Total capital expenditures	$ 495	$ 363

	December 31,	
	2023	2022
	(in millions)	
Total Assets		
Natural Gas	$ 803	$ 697
Electric	3,037	2,723
Total assets	$ 3,840	$ 3,420

	Year Ended December 31,	
	2023	2022
	(in millions)	
Revenues by Products and Services		
Retail electric sales	$ 569	$ 630
Electric delivery	23	26
Wholesale electric sales	20	40
Retail gas sales	128	146
Total	$ 740	$ 842

(13) Supplemental Cash Flow Information

	Year Ended December 31,	
	2023	2022
	(in millions)	
Cash Payments/Receipts:		
Income tax payments	$ 23	$ 17
Interest	43	33
Non-cash transactions:		
Accounts payable related to capital expenditures	$ 20	$ 39
Non-cash contribution from VUH	—	4

The table below provides a reconciliation of cash, cash equivalents and restricted cash reported in the Consolidated Balance Sheets to the amount reported in the Consolidated Statements of Cash Flows:

	December 31,	
	2023	2022
	(in million)	
Cash and cash equivalents (1)	$ 14	$ 5
Restricted cash included in Prepaid expenses and other current assets	3	—
Total cash, cash equivalents and restricted cash shown in Statements of Consolidated Cash Flows	$ 17	$ 5

(1) Cash and cash equivalents related to the VIE as of December 31, 2023 were $14 million. There were no cash and cash equivalents related to the VIE as of December 31, 2022.

(14) Subsequent Events

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, 2024, the date the financial statements were issued.

****

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 2023 consolidated financial statements and notes thereto. The following discussion and analysis should also be read in conjunction with CenterPoint Energy Inc.'s 2023 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 2023, the Company's earnings were $80 million compared to $109 million in 2022, a decrease of $29 million. The unfavorable variance is primarily due to an decrease in margin due to customer rate credits associated with the securitization of the A.B. Brown power plants.

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 Indiana Utility Regulatory Commission (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 IURC 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 (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 IURC 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 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

On December 5, 2023, the Company filed a petition with the IURC for authority to modify its rates and charges for electric utility service through a phase-in of rates. The requested increase is approximately 16% or $119 million based on a forward looking 2025 test year. The need for a rate increase is primarily driven by the continuing investment that is being made to ensure the safety and reliability of the system and normal increases in operating expenses. The rate case reflects a proposed 10.4% ROE on a 55% equity ratio. A hearing is scheduled for late-April through mid-May 2024. A final order is expected in the fourth quarter of 2024.

See Note 9 to the consolidated 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 millions)	2023	2022
Electric revenues (1)	$ 612	$ 696
Cost of fuel & purchased power	175	222
Total Electric margin	**$ 437**	**$ 474**
Margin attributed to:		
Residential & commercial customers	$ 283	$ 285
Industrial customers	80	93
Other	10	10
Regulatory expense recovery mechanisms	34	44
Subtotal: Retail	**407**	**432**
Wholesale margin	30	42
Total Electric margin	**$ 437**	**$ 474**
Electric volumes sold in MWh attributed to:		
Residential & commercial customers	2,452,146	2,608,208
Industrial customers	1,921,852	1,967,271
Other customers	19,694	20,255
Total retail volumes	**4,393,692**	**4,595,734**
Wholesale	510,300	882,864
Total volumes sold	**4,903,992**	**5,478,598**

(1) Includes revenues of $17 millions from the Securitization subsidiary for the year ended December 31, 2023.

Retail
Electric retail utility margins were $407 million for the year ended December 31, 2023, compared to $432 million in 2022, a decrease of $25 million. Changes to margin primarily reflect a $28 million decrease due customer rate credits associated with the securitization of the A.B. Brown power plants, a $11 million decrease due to milder weather, a $2 million decrease due to customer usage and growth, partially offset by an increase of $1 million as a result of the CECA and ECA, a $8 million increase resulting from the TDSIC, and a $3 million increase in miscellaneous revenue. Heating degree days were 82 percent of normal in 2023 compared to 107 percent of normal in 2022, and cooling degree days were 94 percent of normal in 2023 compared to 103 percent of normal in 2022.

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 millions)	2023	2022
MISO transmission system margin	$ 23	$ 26
MISO off-system margin	7	16
Total wholesale margin	**$ 30**	**$ 42**

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms and other transmission system operations, totaled $23 million during 2023 compared to $26 million in 2022, a decrease of $3 million.

For the year ended December 31, 2023, margin from off-system sales was $7 million compared to $16 million in 2022, a decrease of $9 million. The base rate changes implemented in May 2011 require wholesale margin from off-system sales earned above or below $8 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 millions)	2023	2022
Natural Gas revenues	$ 128	$ 146
Cost of gas sold	30	58
Total Natural Gas margin	**$ 98**	**$ 88**
Margin attributed to:		
Residential & commercial customers	$ 72	$ 70
Industrial customers	14	14
Other	1	1
Regulatory expense recovery mechanisms	11	3
Total Natural Gas margin	**$ 98**	**$ 88**
Sold & transported volumes in MDth attributed to:		
Residential & commercial customers	8,208	10,957
Industrial customers	30,288	31,573
Total sold & transported volumes	**38,496**	**42,530**

Natural Gas margin was $98 million for the year ended December 31, 2023 compared to $88 million in 2022, an increase of $10 million. The increase in margin was primarily due to recovery of previously deferred O&M cost through our Compliance and System Improvement Adjustment (CSIA) rider. 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 77 percent of normal in 2023 compared to 98 percent of normal in 2022.

Operating Expenses

<u>Operation and Maintenance</u>
For the year ended December 31, 2023, Operation and maintenance expenses were $251 million compared to $247 million in 2022, an increase of $4 million. The increase in operations and maintenance costs are primarily due to increased pass through costs related to Compliance and System Improvement Adjustment (CSIA) that were partially offset by lower generating facility costs at the end of 2023.

<u>Depreciation & Amortization</u>
Depreciation and amortization expense was $146 million in 2023, compared to $144 million in 2022, an increase of $2 million. The increase resulted from additional utility plant investments placed into service, including property, plant, and equipment assets purchased from CenterPoint Energy at it's net carrying value as of the purchase date.

SELECTED ELECTRIC OPERATING STATISTICS

	For the Year Ended December 31,	
	2023	2022
OPERATING REVENUES (in millions):		
Residential	$ 240	$ 254
Commercial	162	180
Industrial	155	187
Other	12	9
Total Retail	569	630
Net Wholesale Revenues	20	40
Transmission Revenues	23	26
	$ 612	$ 696
MARGIN (In millions):		
Residential	$ 170	$ 172
Commercial	113	113
Industrial	80	93
Other	10	10
Regulatory expense recovery mechanisms	34	44
Total Retail	407	432
Wholesale power & transmission system	30	42
	$ 437	$ 474
ELECTRIC SALES (In MWh):		
Residential	1,335,767	1,398,174
Commercial	1,116,379	1,210,034
Industrial	1,921,852	1,967,271
Other Sales - Street Lighting	19,694	20,255
Total Retail	4,393,692	4,595,734
Wholesale	510,300	882,864
	4,903,992	5,478,598
CUSTOMER COUNT:		
Residential	133,201	132,402
Commercial	19,178	19,135
Industrial	114	114
	152,493	151,651
WEATHER AS A % OF NORMAL:		
Cooling Degree Days	94 %	103 %
Heating Degree Days	82 %	107 %

SELECTED GAS OPERATING STATISTICS

	For the Year Ended December 31,	
	2023	2022
OPERATING REVENUES (in millions):		
Residential	$ 84	$ 94
Commercial	29	39
Industrial	13	12
Other	1	1
	$ 127	$ 146
MARGIN (In millions):		
Residential	$ 56	$ 55
Commercial	16	16
Industrial	14	14
Other	1	1
Regulatory expense recovery mechanisms	11	2
	$ 98	$ 88
GAS SOLD & TRANSPORTED (In MDth):		
Residential	5,343	6,961
Commercial	3,210	3,996
Industrial	30,861	31,573
	39,414	42,530
CUSTOMER COUNT		
Residential	104,725	104,495
Commercial	10,473	10,531
Industrial	133	119
	115,331	115,145