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

# FORM 8-K

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

Date of Report (Date of earliest event reported): **August 3, 2020**

# 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<br>Chicago Stock Exchange, Inc. |
| Depositary Shares for 1/20 of 7.00% Series B Mandatory Convertible Preferred Stock, $0.01 par value | CNP/PB | The New York Stock Exchange |

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

Emerging Growth Company ☐

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

**Item 7.01 Regulation FD Disclosure.**

Included herein is supplemental financial and operational information for the years ended December 31, 2019 and 2018 related to Southern Indiana Gas & Electric Company ("SIGECO"). SIGECO is a wholly-owned subsidiary of Vectren Utility Holdings, Inc. ("VUHI"). VUHI is a wholly-owned subsidiary of Vectren Corporation, which in turn, is a wholly-owned subsidiary of CenterPoint Energy, Inc. ("CenterPoint Energy").

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 | Supplemental Financial and Operational Information for SIGECO for the year ended December 31, 2019 |
| 99.2 | Supplemental Financial and Operational Information for SIGECO for the year ended December 31, 2018 |
| 104 | Cover Page Interactive Data File - the cover page XBRL tags are embedded within the Inline XBRL document |

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

**CENTERPOINT ENERGY, INC.**

Date: August 3, 2020

By: /s/ Kristie L. Colvin

Kristie L. Colvin

Interim Executive Vice President and Chief Financial Officer and Chief Accounting Officer

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**Exhibit 99.1**

***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 2019 financial statements and notes thereto. The following discussion and analysis should also be read in conjunction with CenterPoint Energy Inc.'s 2019 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 2019, the Company's earnings were $56.5 million compared to $81.5 million in 2018. Results in 2019 reflect merger and severance expenses following CenterPoint Energy's acquisition of Vectren and unfavorable weather, partially offset by an increase in electric and gas utility margin from increased returns associated with infrastructure investments (TDSIC, ECA, CECA and CSIA).

## The Regulatory Environment

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

In the Company's natural gas service territory, normal temperature adjustment (NTA) and decoupling mechanisms largely mitigate the effect that would otherwise be caused by variations in volumes sold to residential and commercial customers due to weather and changing consumption patterns. In addition to these mechanisms, the commission has authorized gas and electric infrastructure replacement programs, which allow for recovery of these investments outside of a base rate case proceeding. Further, rates charged to natural gas customers contain a gas cost adjustment (GCA) clause 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. The implementation of these various mechanisms has allowed the Company to avoid regulatory proceedings to increase base rates since 2011 for its electric business and 2007 for its gas business.

*Rate Design Strategies*

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

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

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

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

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

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

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

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

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

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

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

## Operating Trends

### Margin

Throughout this discussion, the terms Gas utility margin and Electric utility margin are used. Gas utility margin is calculated as *Gas utility revenues* less the *Cost of gas sold*. Electric utility margin is calculated as *Electric utility revenues* less *Cost of fuel & purchased power*. The Company believes Gas utility and Electric utility 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 Gas utility margin and Electric utility 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 Utility Margin (Electric utility revenues less Cost of fuel & purchased power)*
Electric utility margin and volumes sold by customer type follows:

| | Year Ended December 31, | | | |
|---|---|---|---|---|
| *(In thousands)* | 2019 | | 2018 | |
| Electric utility revenues | $ | 570,150 | $ | 582,504 |
| Cost of fuel & purchased power | | 165,900 | | 186,203 |
| **Total electric utility margin** | **$** | **404,250** | **$** | **396,301** |
| Margin attributed to: | | | | |
| Residential & commercial customers | $ | 255,545 | $ | 251,443 |
| Industrial customers | | 95,107 | | 93,604 |
| Other | | 6,194 | | 5,689 |
| Regulatory expense recovery mechanisms | | 17,456 | | 15,666 |
| **Subtotal: Retail** | | **374,302** | | **366,402** |
| Wholesale margin | | 29,948 | | 29,899 |
| **Total electric utility margin** | **$** | **404,250** | **$** | **396,301** |
| Electric volumes sold in MWh attributed to: | | | | |
| Residential & commercial customers | | 2,608,827 | | 2,754,307 |
| Industrial customers | | 2,072,912 | | 2,181,464 |
| Other customers | | 21,113 | | 22,251 |
| **Total retail volumes** | | **4,702,852** | | **4,958,022** |
| Wholesale | | 495,281 | | 856,350 |
| **Total volumes sold** | | **5,198,133** | | **5,814,372** |

*Retail*
Electric retail utility margins were $374.3 million for the year ended December 31, 2019, compared to $366.4 million in 2018, an increase of $7.9 million. Results primarily reflect an increase in margin of $14.1 million as a result of the Clean Energy Cost Adjustment and Environmental Cost Adjustment (CECA and ECA) and a $5.5 million increase resulting from the Transmission, Distribution and Storage System Improvement Charge (TDSIC). The increase was partially offset by a $8.1 million decrease in margin due to unfavorable weather along with a $3.2 million decrease in margin resulting from a decline in large industrial customer usage. Heating degree days were 95 percent of normal in 2019 compared to 101 percent of normal in 2018, and cooling degree days were 115 percent of normal in 2019 compared to 136 percent of normal in 2018.

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

| | Year Ended December 31, | | | |
|---|---|---|---|---|
| *(In thousands)* | 2019 | | 2018 | |
| MISO transmission system margin | $ | 24,957 | $ | 23,203 |
| MISO off-system margin | | 4,991 | | 6,696 |
| **Total wholesale margin** | **$** | **29,948** | **$** | **29,899** |

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms and other transmission system operations, totaled $25.0 million during 2019 compared to $23.2 million in 2018, an increase of $1.8 million. As of December 31, 2019, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $126.7 million at December 31, 2019. These projects include an interstate 345 kV transmission line that connects the Company's A.B. Brown Generating Station to a generating station in Indiana owned by Duke Energy to the north and to a generating station in Kentucky owned by Big Rivers Electric Corporation to the south; a substation; and another transmission line. These projects earn the FERC approved equity rate of return on the net plant balance and recover operating expenses. In November 2019, the FERC issued an order authorizing the transmission owners to receive a 9.88 percent base ROE compared to the previously authorized 10.32 percent, plus a separately approved 50 basis point adder. The 345 kV project is the largest of these qualifying projects, with an original cost of $106.8 million.

For the year ended December 31, 2019, margin from off-system sales was $5.0 million compared to $6.7 million in 2018, a decrease of $1.7 million. The base rate changes implemented in May 2011 require wholesale margin from off-system sales earned above or below $7.5 million per year to be shared equally with customers. Results, net of sharing for the periods presented, were unfavorable in 2019 compared to 2018, reflecting lower market prices due primarily to lower natural gas prices.

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

| | Year Ended December 31, | | | |
|---|---|---|---|---|
| *(In thousands)* | 2019 | | 2018 | |
| Gas utility revenues | $ | 99,531 | $ | 100,044 |
| Cost of gas sold | | 33,623 | | 40,309 |
| **Total gas utility margin** | **$** | **65,908** | **$** | **59,735** |
| Margin attributed to: | | | | |
| Residential & commercial customers | $ | 45,316 | $ | 42,898 |
| Industrial customers | | 10,781 | | 10,108 |
| Other | | 852 | | 221 |
| Regulatory expense recovery mechanisms | | 8,959 | | 6,508 |
| **Total gas utility margin** | **$** | **65,908** | **$** | **59,735** |
| Sold & transported volumes in MDth attributed to: | | | | |
| Residential & commercial customers | | 10,439 | | 10,794 |
| Industrial customers | | 30,170 | | 32,825 |
| **Total sold & transported volumes** | | **40,609** | | **43,619** |

Gas Utility margin was $65.9 million for the year ended December 31, 2019 compared to $59.7 million in 2018, an increase of $6.2 million. The increase in margin was largely due to increased returns on the Compliance and System Improvement Adjustment (CSIA). Weather has relatively no impact on customer margin due to the Company's rate design. The decrease in sold and transported volumes was primarily due to weather. Heating degree days were 95 percent of normal in 2019 compared to 101 percent of normal in 2018.

**Operating Expenses**

<u>Other Operating</u>
For the year ended December 31, 2019, *Other operating* expenses were $241.9 million compared to $203.6 million in 2018, an increase of $38.3 million.  Operating expenses primarily reflect an increase of $29.6 million from merger and severance expenses following CenterPoint Energy's acquisition of Vectren and a $6.2 million increase due to operating expenses recovered through margin. The remaining increase in operating expenses can be primarily attributed to major maintenance outages at two of the Company's generating units.

Depreciation & Amortization
Depreciation and amortization expense was $114.0 million in 2019, compared to $104.7 million in 2018, an increase of $9.3 million. The increase resulted from additional utility plant investments placed into service, including $6.2 million of depreciation on infrastructure investments.

**SELECTED ELECTRIC OPERATING STATISTICS**

| | For the Year Ended December 31, | |
|---|---|---|
| | 2019 | 2018 |
| OPERATING REVENUES (in thousands): | | |
| Residential | $ 210,443 | $ 210,232 |
| Commercial | 148,094 | 149,255 |
| Industrial | 159,892 | 162,143 |
| Other | 9,355 | 9,138 |
| Total Retail | 527,784 | 530,768 |
| Net Wholesale Revenues | 42,366 | 51,736 |
| | $ 570,150 | $ 582,504 |
| | | |
| MARGIN (In thousands): | | |
| Residential | $ 153,801 | $ 151,168 |
| Commercial | 101,744 | 100,275 |
| Industrial | 95,107 | 93,604 |
| Other | 6,194 | 5,689 |
| Regulatory expense recovery mechanisms | 17,456 | 15,666 |
| Total Retail | 374,302 | 366,402 |
| Wholesale power & transmission system | 29,948 | 29,899 |
| | $ 404,250 | $ 396,301 |
| | | |
| ELECTRIC SALES (In MWh): | | |
| Residential | 1,409,212 | 1,486,582 |
| Commercial | 1,199,615 | 1,267,725 |
| Industrial | 2,072,912 | 2,181,464 |
| Other Sales - Street Lighting | 21,113 | 22,251 |
| Total Retail | 4,702,852 | 4,958,022 |
| Wholesale | 495,281 | 856,350 |
| | 5,198,133 | 5,814,372 |
| | | |
| AVERAGE CUSTOMERS: | | |
| Residential | 128,344 | 127,439 |
| Commercial | 18,751 | 18,677 |
| Industrial | 116 | 115 |
| Other | 42 | 40 |
| | 147,253 | 146,271 |
| | | |
| WEATHER AS A % OF NORMAL: | | |
| Cooling Degree Days | 115% | 136% |
| Heating Degree Days | 95% | 101% |

## SELECTED GAS OPERATING STATISTICS

| | For the Year Ended December 31, | | | |
|---|---|---|---|---|
| | 2019 | | 2018 | |
| OPERATING REVENUES (In thousands): | | | | |
| Residential | $ | 64,743 | $ | 65,125 |
| Commercial | | 22,507 | | 24,055 |
| Industrial | | 12,039 | | 10,576 |
| Other | | 242 | | 288 |
| | $ | 99,531 | $ | 100,044 |
| MARGIN (In thousands): | | | | |
| Residential | $ | 35,690 | $ | 33,549 |
| Commercial | | 9,626 | | 9,349 |
| Industrial | | 10,781 | | 10,108 |
| Other | | 852 | | 221 |
| Regulatory expense recovery mechanisms | | 8,959 | | 6,508 |
| | $ | 65,908 | $ | 59,735 |
| GAS SOLD & TRANSPORTED (In MDth): | | | | |
| Residential | | 6,713 | | 6,992 |
| Commercial | | 3,726 | | 3,802 |
| Industrial | | 30,170 | | 32,825 |
| | | 40,609 | | 43,619 |
| AVERAGE CUSTOMERS: | | | | |
| Residential | | 101,906 | | 101,475 |
| Commercial | | 10,356 | | 10,342 |
| Industrial | | 112 | | 112 |
| | | 112,374 | | 111,929 |

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**Exhibit 99.2**

***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 2018 financial statements and notes thereto. The following discussion and analysis should also be read in conjunction with CenterPoint Energy Inc.'s 2018 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 2018, the Company's earnings were $81.5 million compared to $79.9 million in 2017. Results in 2018 reflect an increase in electric earnings due primarily to favorable weather and increased earnings from the Transmission Distribution and Storage System Improvement Charge (TDSIC), offset by tax reform and power plant maintenance. Additionally, gas earnings increased primarily from the Compliance and System Improvement Adjustment (CSIA).

## The Regulatory Environment

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

In the Company's natural gas service territory, normal temperature adjustment (NTA) and decoupling mechanisms largely mitigate the effect that would otherwise be caused by variations in volumes sold to residential and commercial customers due to weather and changing consumption patterns. In addition to these mechanisms, the commission has authorized gas and electric infrastructure replacement programs, which allow for recovery of these investments outside of a base rate case proceeding. Further, rates charged to natural gas customers contain a gas cost adjustment (GCA) clause 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. The implementation of these various mechanisms has allowed the Company to avoid regulatory proceedings to increase base rates since 2011 for its electric business and 2007 for its gas business.

*Rate Design Strategies*

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

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

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

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

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

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

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

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

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

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

See Notes 9 and 10 to the financial statements for more specific information on the significant regulatory proceedings involving the Company.

## Operating Trends

### Margin

Throughout this discussion, the terms Gas utility margin and Electric utility margin are used. Gas utility margin is calculated as *Gas utility revenues* less the *Cost of gas sold*. Electric utility margin is calculated as *Electric utility revenues* less *Cost of fuel & purchased power*. The Company believes Gas utility and Electric utility 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 Gas utility margin and Electric utility 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 Utility Margin (Electric utility revenues less Cost of fuel & purchased power)*
Electric utility margin and volumes sold by customer type follows:

| | Year Ended December 31, | | | |
|---|---|---|---|---|
| *(In thousands)* | | 2018 | | 2017 |
| Electric utility revenues | $ | 582,504 | $ | 569,587 |
| Cost of fuel & purchased power | | 186,203 | | 171,794 |
| **Total electric utility margin** | **$** | **396,301** | **$** | **397,793** |
| Margin attributed to: | | | | |
| Residential & commercial customers | $ | 251,443 | $ | 254,838 |
| Industrial customers | | 93,604 | | 96,913 |
| Other | | 5,689 | | 5,617 |
| Regulatory expense recovery mechanisms | | 15,666 | | 9,611 |
| **Subtotal: Retail** | | **366,402** | | **366,979** |
| Wholesale margin | | 29,899 | | 30,814 |
| **Total electric utility margin** | **$** | **396,301** | **$** | **397,793** |
| Electric volumes sold in MWh attributed to: | | | | |
| Residential & commercial customers | | 2,754,307 | | 2,638,783 |
| Industrial customers | | 2,181,464 | | 2,096,523 |
| Other customers | | 22,251 | | 22,261 |
| **Total retail volumes** | | **4,958,022** | | **4,757,567** |
| Wholesale | | 856,350 | | 463,252 |
| **Total volumes sold** | | **5,814,372** | | **5,220,819** |

*Retail*
Electric retail utility margins were $366.4 million for the year ended December 31, 2018 compared to $367.0 million in 2017, a decrease of $0.6 million. Results reflect a decrease in margin of $26.1 million as a result of federal tax reform implemented effective January 1, 2018. The decrease was largely offset by increases in margin of $13.8 million due to favorable weather, of $4.5 million due to large customer usage, and of $5.8 million due to regulatory expense recovery mechanisms. Heating degree days were 101 percent of normal in 2018 compared to 80 percent of normal in 2017, and cooling degree days were 136 percent of normal in 2018 compared to 111 percent of normal in 2017.

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

| | Year Ended December 31, | | | |
|---|---|---|---|---|
| *(In thousands)* | | 2018 | | 2017 |
| MISO transmission system margin | $ | 23,203 | $ | 25,498 |
| MISO off-system margin | | 6,696 | | 5,316 |
| **Total wholesale margin** | **$** | **29,899** | **$** | **30,814** |

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms and other transmission system operations, totaled $23.2 million during 2018 compared to $25.5 million in 2017, a decrease of $2.3 million. As of December 31, 2018, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $130.1 million at December 31, 2018. These projects include an interstate 345 kV transmission line that connects the Company’s A.B. Brown Generating Station to a generating station in Indiana owned by Duke Energy to the north and to a generating station in Kentucky owned by Big Rivers Electric Corporation to the south; a substation; and another transmission line. These projects earn the FERC approved equity rate of return on the net plant balance and recover operating expenses. In September 2016, the FERC issued an order authorizing the transmission owners to receive a 10.32 percent base ROE, plus a separately approved 50 basis point adder. The 345 kV project is the largest of these qualifying projects with an original cost of $106.8 million.

For the year ended December 31, 2018, margin from off-system sales was $6.7 million compared to $5.3 million in 2017, an increase of $1.4 million. The base rate changes implemented in May 2011 require wholesale margin from off-system sales earned above or below $7.5 million per year to be shared equally with customers. Results, net of sharing for the periods presented, were favorable in 2018 compared to 2017, reflecting higher market prices due primarily to higher natural gas prices.

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

| | Year Ended December 31, | | | |
|---|---|---|---|---|
| *(In thousands)* | 2018 | | 2017 | |
| Gas utility revenues | $ | 100,044 | $ | 92,396 |
| Cost of gas sold | | 40,309 | | 33,949 |
| **Total gas utility margin** | **$** | **59,735** | **$** | **58,447** |
| Margin attributed to: | | | | |
| Residential & commercial customers | $ | 42,898 | $ | 41,964 |
| Industrial customers | | 10,108 | | 9,956 |
| Other | | 221 | | 1,004 |
| Regulatory expense recovery mechanisms | | 6,508 | | 5,523 |
| **Total gas utility margin** | **$** | **59,735** | **$** | **58,447** |
| Sold & transported volumes in MDth attributed to: | | | | |
| Residential & commercial customers | | 10,794 | | 9,113 |
| Industrial customers | | 32,825 | | 28,771 |
| **Total sold & transported volumes** | | **43,619** | | **37,884** |

Gas Utility margin was $59.7 million for the year ended December 31, 2018 compared to $58.4 million in 2017, an increase of $1.3 million. The increase in margin was largely due to increased returns on the gas infrastructure replacement program and to the margin impact of regulatory expense recovery mechanisms, offset by the $4.7 million margin impact of federal tax reform. Weather has relatively no impact on customer margin due to the Company's rate design. The increase in sold and transported volumes was primarily due to weather. Heating degree days were 101 percent of normal in 2018 compared to 80 percent of normal in 2017.

**Operating Expenses**

Other Operating
For the year ended December 31, 2018, *Other operating* expenses were $203.6 million compared to $187.8 million in 2017, an increase of $15.8 million. Operating expenses primarily reflect an increase of $9.6 million in power plant maintenance expense and variable production costs and an increase of $6.4 million due to operating expenses recovered through margin.

Depreciation & Amortization
Depreciation and amortization expense was $104.7 million in 2018 compared to $100.8 million in 2017, an increase of $3.9 million. The increase resulted from additional utility plant investments placed into service, including $1.2 million of depreciation on infrastructure investments.

## SELECTED ELECTRIC OPERATING STATISTICS

| | For the Year Ended December 31, | |
|---|---|---|
| | 2018 | 2017 |
| OPERATING REVENUES (in thousands): | | |
| Residential | $ 210,232 | $ 200,821 |
| Commercial | 149,255 | 154,564 |
| Industrial | 162,143 | 162,586 |
| Other | 9,138 | 9,246 |
| Total Retail | 530,768 | 527,217 |
| Net Wholesale Revenues | 51,736 | 42,370 |
| | $ 582,504 | $ 569,587 |
| MARGIN (In thousands): | | |
| Residential | $ 151,168 | $ 148,555 |
| Commercial | 100,275 | 106,283 |
| Industrial | 93,604 | 96,913 |
| Other | 5,689 | 5,617 |
| Regulatory expense recovery mechanisms | 15,666 | 9,611 |
| Total Retail | 366,402 | 366,979 |
| Wholesale power & transmission system | 29,899 | 30,814 |
| | $ 396,301 | $ 397,793 |
| ELECTRIC SALES (In MWh): | | |
| Residential | 1,486,582 | 1,362,457 |
| Commercial | 1,267,725 | 1,276,326 |
| Industrial | 2,181,464 | 2,096,523 |
| Other Sales - Street Lighting | 22,251 | 22,261 |
| Total Retail | 4,958,022 | 4,757,567 |
| Wholesale | 856,350 | 463,252 |
| | 5,814,372 | 5,220,819 |
| AVERAGE CUSTOMERS: | | |
| Residential | 127,439 | 126,443 |
| Commercial | 18,677 | 18,648 |
| Industrial | 115 | 112 |
| Other | 40 | 40 |
| | 146,271 | 145,243 |
| WEATHER AS A % OF NORMAL: | | |
| Cooling Degree Days | 136% | 111% |
| Heating Degree Days | 101% | 80% |

## SELECTED GAS OPERATING STATISTICS

| | For the Year Ended December 31, | | | |
|---|---|---|---|---|
| | 2018 | | 2017 | |
| OPERATING REVENUES (In thousands): | | | | |
| Residential | $ | 65,125 | $ | 60,097 |
| Commercial | | 24,055 | | 21,428 |
| Industrial | | 10,576 | | 9,820 |
| Other | | 288 | | 1,051 |
| | $ | 100,044 | $ | 92,396 |
| MARGIN (In thousands): | | | | |
| Residential | $ | 33,549 | $ | 32,707 |
| Commercial | | 9,349 | | 9,257 |
| Industrial | | 10,108 | | 9,956 |
| Other | | 221 | | 1,004 |
| Regulatory expense recovery mechanisms | | 6,508 | | 5,523 |
| | $ | 59,735 | $ | 58,447 |
| GAS SOLD & TRANSPORTED (In MDth): | | | | |
| Residential | | 6,992 | | 5,860 |
| Commercial | | 3,802 | | 3,253 |
| Industrial | | 32,825 | | 28,771 |
| | | 43,619 | | 37,884 |
| AVERAGE CUSTOMERS: | | | | |
| Residential | | 101,475 | | 101,064 |
| Commercial | | 10,342 | | 10,304 |
| Industrial | | 112 | | 112 |
| | | 111,929 | | 111,480 |