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

FORM 10-Q

(mark one)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2019

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number: 1-10499

NorthWestern Energy

NORTHWESTERN CORP

(Exact name of registrant as specified in its charter)

Delaware	**46-0172280**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
3010 W. 69th Street Sioux Falls South Dakota	**57108**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: 605-978-2900

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	NWE	NYSE

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non- accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer", "smaller reporting company", and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer ☒ Accelerated Filer ☐ Non-accelerated Filer ☐ Smaller Reporting Company ☐ 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. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes☐ No ☒

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date:

Common Stock, Par Value $0.01, 50,446,835 shares outstanding at October 25, 2019

NORTHWESTERN CORPORATION

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

On one or more occasions, we may make statements in this Quarterly Report on Form 10-Q regarding our assumptions, projections, expectations, targets, intentions or beliefs about future events. All statements other than statements of historical facts, included or incorporated by reference in this Quarterly Report, relating to management's current expectations of future financial performance, continued growth, changes in economic conditions or capital markets and changes in customer usage patterns and preferences are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934.

Words or phrases such as “anticipates," “may," “will," “should," “believes," “estimates," “expects," “intends," “plans," “predicts," “projects," “targets," “will likely result," “will continue" or similar expressions identify forward-looking statements. Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed. We caution that while we make such statements in good faith and believe such statements are based on reasonable assumptions, including without limitation, management's examination of historical operating trends, data contained in records and other data available from third parties, we cannot assure you that we will achieve our projections. Factors that may cause such differences include, but are not limited to:

- adverse determinations by regulators, as well as potential adverse federal, state, or local legislation or regulation, including costs of compliance with existing and future environmental requirements, could have a material effect on our liquidity, results of operations and financial condition;
- changes in availability of trade credit, creditworthiness of counterparties, usage, commodity prices, fuel supply costs or availability due to higher demand, shortages, weather conditions, transportation problems or other developments, may reduce revenues or may increase operating costs, each of which could adversely affect our liquidity and results of operations;
- unscheduled generation outages or forced reductions in output, maintenance or repairs, which may reduce revenues and increase cost of sales or may require additional capital expenditures or other increased operating costs; and
- adverse changes in general economic and competitive conditions in the U.S. financial markets and in our service territories.

We have attempted to identify, in context, certain of the factors that we believe may cause actual future experience and results to differ materially from our current expectation regarding the relevant matter or subject area. In addition to the items specifically discussed above, our business and results of operations are subject to the uncertainties described under the caption “Risk Factors” which is part of the disclosure included in Part II, Item 1A of this Quarterly Report on Form 10-Q.

From time to time, oral or written forward-looking statements are also included in our reports on Forms 10-K, 10-Q and 8-K, Proxy Statements on Schedule 14A, press releases, analyst and investor conference calls, and other communications released to the public. We believe that at the time made, the expectations reflected in all of these forward-looking statements are and will be reasonable. However, any or all of the forward-looking statements in this Quarterly Report on Form 10-Q, our reports on Forms 10-K and 8-K, our other reports on Form 10-Q, our Proxy Statements on Schedule 14A and any other public statements that are made by us may prove to be incorrect. This may occur as a result of assumptions, which turn out to be inaccurate, or as a consequence of known or unknown risks and uncertainties. Many factors discussed in this Quarterly Report on Form 10-Q, certain of which are beyond our control, will be important in determining our future performance. Consequently, actual results may differ materially from those that might be anticipated from forward-looking statements. In light of these and other uncertainties, you should not regard the inclusion of any of our forward-looking statements in this Quarterly Report on Form 10-Q or other public communications as a representation by us that our plans and objectives will be achieved, and you should not place undue reliance on such forward-looking statements.

We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. However, your attention is directed to any further disclosures made on related subjects in our subsequent reports filed with the Securities and Exchange Commission (SEC) on Forms 10-K, 10-Q and 8-K and Proxy Statements on Schedule 14A.

Unless the context requires otherwise, references to “we,” “us,” “our,” “NorthWestern Corporation,” “NorthWestern Energy,” and “NorthWestern” refer specifically to NorthWestern Corporation and its subsidiaries.

ITEM 1. FINANCIAL STATEMENTS (UNAUDITED)

NORTHWESTERN CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(Unaudited)

(in thousands, except per share amounts)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Revenues				
Electric	$ 241,237	$ 245,159	$ 733,933	$ 693,256
Gas	33,599	34,715	195,842	189,937
Total Revenues	274,836	279,874	929,775	883,193
Operating Expenses				
Cost of sales	64,227	72,247	235,706	200,514
Operating, general and administrative	76,998	73,787	238,916	221,966
Property and other taxes	44,089	42,451	133,188	128,306
Depreciation and depletion	43,166	43,581	129,766	130,877
Total Operating Expenses	228,480	232,066	737,576	681,663
Operating Income	46,356	47,808	192,199	201,530
Interest Expense, net	(23,722)	(22,035)	(71,023)	(68,202)
Other (Expense) Income, net	(409)	2,051	864	1,798
Income Before Income Taxes	22,225	27,824	122,040	135,126
Income Tax (Expense) Benefit	(555)	358	20,098	(4,658)
Net Income	$ 21,670	$ 28,182	$ 142,138	$ 130,468
Average Common Shares Outstanding	50,444	50,318	50,422	49,871
Basic Earnings per Average Common Share	$ 0.43	$ 0.56	$ 2.82	$ 2.62
Diluted Earnings per Average Common Share	$ 0.42	$ 0.56	$ 2.80	$ 2.61
Dividends Declared per Common Share	$ 0.575	$ 0.55	$ 1.725	$ 1.65

See Notes to Condensed Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)

(in thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	**2018**	**2019**	**2018**
Net Income	$ 21,670	$ 28,182	$ 142,138	$ 130,468
Other comprehensive income, net of tax:				
Foreign currency translation	42	(68)	18	113
Reclassification of net losses on derivative instruments	114	113	339	339
Total Other Comprehensive Income	156	45	357	452
Comprehensive Income	$ 21,826	$ 28,227	$ 142,495	$ 130,920

See Notes to Condensed Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

(in thousands, except share data)

	September 30, 2019	December 31, 2018
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 5,046	$ 7,860
Restricted cash	9,055	7,451
Accounts receivable, net	126,373	162,373
Inventories	55,168	50,815
Regulatory assets	56,093	38,431
Other	14,087	10,755
Total current assets	**265,822**	**277,685**
Property, plant, and equipment, net	4,650,951	4,521,318
Goodwill and other intangibles, net	357,986	357,586
Regulatory assets	470,781	437,581
Other noncurrent assets	64,640	50,206
Total Assets	**$ 5,810,180**	**$ 5,644,376**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Finance leases	$ 2,430	$ 2,298
Accounts payable	66,550	87,043
Accrued expenses and other	243,093	216,792
Regulatory liabilities	21,611	40,876
Total current liabilities	**333,684**	**347,009**
Long-term finance leases	18,081	19,915
Long-term debt	2,176,057	2,102,345
Deferred income taxes	431,832	394,618
Noncurrent regulatory liabilities	451,006	438,285
Other noncurrent liabilities	394,996	399,822
Total Liabilities	**3,805,656**	**3,701,994**
Commitments and Contingencies (Note 10)		
Shareholders' Equity:		
Common stock, par value $0.01; authorized 200,000,000 shares; issued and outstanding 53,996,070 and 50,445,969 shares, respectively; Preferred stock, par value $0.01; authorized 50,000,000 shares; none issued	540	539
Treasury stock at cost	(96,092)	(95,546)
Paid-in capital	1,505,605	1,499,070
Retained earnings	604,048	548,253
Accumulated other comprehensive loss	(9,577)	(9,934)
Total Shareholders' Equity	**2,004,524**	**1,942,382**
Total Liabilities and Shareholders' Equity	**$ 5,810,180**	**$ 5,644,376**

See Notes to Condensed Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(in thousands)

	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
OPERATING ACTIVITIES:		
Net income	$ 142,138	$ 130,468
Items not affecting cash:		
Depreciation and depletion	129,766	130,877
Amortization of debt issue costs, discount and deferred hedge gain	3,482	3,488
Stock-based compensation costs	4,778	4,935
Equity portion of allowance for funds used during construction	(4,118)	(2,737)
Gain on disposition of assets	(176)	(55)
Deferred income taxes	(16,350)	6,287
Changes in current assets and liabilities:		
Accounts receivable	36,000	54,352
Inventories	(4,353)	(306)
Other current assets	(3,332)	(904)
Accounts payable	(13,942)	(19,090)
Accrued expenses	24,945	53,031
Regulatory assets	(17,662)	(1,915)
Regulatory liabilities	(19,265)	6,955
Other noncurrent assets	(5,366)	(8,031)
Other noncurrent liabilities	(2,684)	(10,937)
Cash Provided by Operating Activities	**253,861**	**346,418**
INVESTING ACTIVITIES:		
Property, plant, and equipment additions	(242,874)	(193,405)
Acquisitions	—	(18,504)
Proceeds from sale of assets	—	72
Cash Used in Investing Activities	**(242,874)**	**(211,837)**
FINANCING ACTIVITIES:		
Treasury stock activity	1,220	2,056
Proceeds from issuance of common stock, net	—	44,797
Dividends on common stock	(86,343)	(81,723)
Issuance of long-term debt	150,000	—
Line of credit repayments, net	(76,000)	—
Line of credit borrowings	—	1,433,000
Line of credit repayments	—	(1,211,000)
Repayments of short-term borrowings, net	—	(319,556)
Financing costs	(1,074)	(91)
Cash Used in Financing Activities	**(12,197)**	**(132,517)**
(Decrease) Increase in Cash, Cash Equivalents, and Restricted Cash	(1,210)	2,064
Cash, Cash Equivalents, and Restricted Cash, beginning of period	15,311	12,029
Cash, Cash Equivalents, and Restricted Cash, end of period	**$ 14,101**	**$ 14,093**
Supplemental Cash Flow Information:		
Cash paid during the period for:		
Income taxes	$ 68	$ 55
Interest	55,515	49,002
Significant non-cash transactions:		
Capital expenditures included in accounts payable	15,508	11,893

See Notes to Condensed Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(Unaudited)

(in thousands, except per share data)

	Three Months Ended September 30,							
	Number of Common Shares	Number of Treasury Shares	Common Stock	Treasury Stock	Paid in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Shareholders' Equity
Balance at June 30, 2018	**53,889**	**3,574**	**$ 539**	**$ (95,768)**	**$1,494,940**	**$508,528**	**$ (10,508)**	**$ 1,897,731**
Net income	—	—	—	—	—	28,182	—	28,182
Foreign currency translation adjustment	—	—	—	—	—	—	(68)	(68)
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	113	113
Stock-based compensation	—	42	(1)	(56)	1,186	—	—	1,129
Issuance of shares	—	(47)	1	190	92	—	—	283
Dividends on common stock ($0.55 per share)	—	—	—	—	—	(27,470)	—	(27,470)
Balance at September 30, 2018	**53,889**	**3,569**	**$ 539**	**$ (95,634)**	**$1,496,218**	**$509,240**	**$ (10,463)**	**$ 1,899,900**
Balance at June 30, 2019	**53,996**	**3,553**	**$ 540**	**$ (96,178)**	**$1,504,290**	**$611,159**	**$ (9,733)**	**$ 2,010,078**
Net income	—	—	—	—	—	21,670	—	21,670
Foreign currency translation adjustment	—	—	—	—	—	—	42	42
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	114	114
Stock-based compensation	—	—	—	—	1,169	—	—	1,169
Issuance of shares	—	(3)	—	86	146	—	—	232
Dividends on common stock ($0.575 per share)	—	—	—	—	—	(28,781)	—	(28,781)
Balance at September 30, 2019	**53,996**	**3,550**	**$ 540**	**$ (96,092)**	**$1,505,605**	**$604,048**	**$ (9,577)**	**$ 2,004,524**

	Nine Months Ended September 30,							
	Number of Common Shares	Number of Treasury Shares	Common Stock	Treasury Stock	Paid in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Shareholders' Equity
Balance at December 31, 2017	**52,981**	**3,609**	**$ 530**	**$ (96,376)**	**$ 1,445,181**	**$ 458,352**	**$ (8,772)**	**$ 1,798,915**
Net income	—	—	—	—	—	130,468	—	130,468
Foreign currency translation adjustment	—	—	—	—	—	—	113	113
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	339	339
Reclassification of certain tax effects from AOCL	—	—	—	—	—	2,143	(2,143)	—
Stock-based compensation	72	12	—	(668)	4,903	—	—	4,235
Issuance of shares	836	(52)	9	1,410	46,134	—	—	47,553
Dividends on common stock ($1.65 per share)	—	—	—	—	—	(81,723)	—	(81,723)
Balance at September 30, 2018	**53,889**	**3,569**	**$ 539**	**$ (95,634)**	**$ 1,496,218**	**$ 509,240**	**$ (10,463)**	**$ 1,899,900**
Balance at December 31, 2018	**53,889**	**3,566**	**$ 539**	**$ (95,546)**	**$ 1,499,070**	**$ 548,253**	**$ (9,934)**	**$ 1,942,382**
Net income	—	—	—	—	—	142,138	—	142,138
Foreign currency translation adjustment	—	—	—	—	—	—	18	18
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	339	339
Stock-based compensation	107	25	—	(1,646)	4,744	—	—	3,098
Issuance of shares	—	(41)	1	1,100	1,791	—	—	2,892
Dividends on common stock ($1.725 per share)	—	—	—	—	—	(86,343)	—	(86,343)
Balance at September 30, 2019	**53,996**	**3,550**	**$ 540**	**$ (96,092)**	**$ 1,505,605**	**$ 604,048**	**$ (9,577)**	**$ 2,004,524**

See Notes to Condensed Consolidated Financial Statements

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Reference is made to Notes to Financial Statements included in NorthWestern Corporation's Annual Report)
(Unaudited)

(1) Nature of Operations and Basis of Consolidation

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and/or natural gas to approximately 726,400 customers in Montana, South Dakota and Nebraska.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that may affect the reported amounts of assets, liabilities, revenues and expenses during the reporting period. Actual results could differ from those estimates. The unaudited Condensed Consolidated Financial Statements (Financial Statements) reflect all adjustments (which unless otherwise noted are normal and recurring in nature) that are, in the opinion of management, necessary to fairly present our financial position, results of operations and cash flows. The actual results for the interim periods are not necessarily indicative of the operating results to be expected for a full year or for other interim periods. Events occurring subsequent to September 30, 2019, have been evaluated as to their potential impact to the Financial Statements through the date of issuance.

The Financial Statements included herein have been prepared by NorthWestern, without audit, pursuant to the rules and regulations of the SEC. Certain information and footnote disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations; however, management believes that the condensed disclosures provided are adequate to make the information presented not misleading. Management recommends that these Financial Statements be read in conjunction with the audited financial statements and related footnotes included in our Annual Report on Form 10-K for the year ended December 31, 2018.

Variable Interest Entities

A reporting company is required to consolidate a variable interest entity (VIE) as its primary beneficiary, which means it has a controlling financial interest, when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance, and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE. An entity is considered to be a VIE when its total equity investment at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support, or its equity investors, as a group, lack the characteristics of having a controlling financial interest. The determination of whether a company is required to consolidate an entity is based on, among other things, an entity's purpose and design and a company's ability to direct the activities of the entity that most significantly impact the entity's economic performance.

Certain long-term purchase power and tolling contracts may be considered variable interests. We have various long-term purchase power contracts with other utilities and certain qualifying co-generation facilities and qualifying small power production facilities (QF). We identified one QF contract that may constitute a VIE. We entered into a 40-year power purchase contract in 1984 with this 35 megawatt (MW) coal-fired QF to purchase substantially all of the facility's capacity and electrical output over a substantial portion of its estimated useful life. We absorb a portion of the facility's variability through annual changes to the price we pay per megawatt hour (MWH). After making exhaustive efforts, we have been unable to obtain the information from the facility necessary to determine whether the facility is a VIE or whether we are the primary beneficiary of the facility. The contract with the facility contains no provision which legally obligates the facility to release this information. We have accounted for this QF contract as an executory contract. Based on the current contract terms with this QF, our estimated gross contractual payments aggregate approximately $148.5 million through 2024.

Accounting Standards Adopted

Leases - In February 2016, the Financial Accounting Standards Board (FASB) issued revised guidance requiring substantially all leases to be recognized on the balance sheet as right-of-use assets and lease liabilities. Leases with a term of 12 months or less may be excluded from the balance sheet and continue to be reflected in the income statement. Recognition, measurement and presentation of expenses depends on classification as a finance or operating lease.

We adopted this standard on January 1, 2019, using the modified retrospective method of adoption. Adoption of this standard had minimal impact on our Financial Statements and disclosures. We elected a package of practical expedients that allow us to carry forward historical conclusions related to (1) whether any expired or existing contract is a lease or contains a lease, (2) the lease classification of any expired or existing leases and easements, and (3) the initial direct costs for any existing leases. In addition, as our easements are entered into in perpetuity, they do not meet the definition of a lease in accordance with this guidance. We did not restate comparative periods upon adoption. We had one finance lease that was already included on our balance sheets prior to adoption of the lease standard, consistent with previous guidance for capital leases. We also lease office equipment and facilities under various long-term operating leases. The recognition of right-of-use assets and lease liabilities for operating leases increased our assets and liabilities by approximately $3.6 million and are classified in the Condensed Consolidated Balance Sheets as follows (in thousands):

	Affected Line Item in the Condensed Consolidated Balance Sheets	September 30, 2019
Operating lease assets	Other noncurrent assets	**$ 3,598**
Operating lease liabilities, current	Accrued expenses and other	1,356
Operating lease liabilities, noncurrent	Other noncurrent liabilities	2,242
Total operating lease liabilities		**$ 3,598**

Supplemental Cash Flow Information

The following table provides a reconciliation of cash, cash equivalents, and restricted cash reported within the Condensed Consolidated Balance Sheets that sum to the total of the same such amounts shown in the Condensed Consolidated Statements of Cash Flows (in thousands):

	September 30, 2019	December 31, 2018	September 30, 2018	December 31, 2017
Cash and cash equivalents	$ 5,046	$ 7,860	$ 6,912	$ 8,473
Restricted cash	9,055	7,451	7,181	3,556
Total cash, cash equivalents, and restricted cash shown in the Condensed Consolidated Statements of Cash Flows	$ 14,101	$ 15,311	$ 14,093	$ 12,029

Goodwill

We completed our annual goodwill impairment test as of April 1, 2019 and no impairment was identified. We calculate the fair value of our reporting units by considering various factors, including valuation studies based primarily on a discounted cash flow analysis, with published industry valuations and market data as supporting information. Key assumptions in the determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate expected long-term growth rates in our service territory, regulatory stability, and commodity prices (where appropriate), as well as other factors that affect our revenue, expense and capital expenditure projections.

(2) Regulatory Matters

Montana General Electric Rate Case

In September 2018, we filed an electric rate case with the Montana Public Service Commission (MPSC) requesting an annual increase to electric rates of approximately $34.9 million. The MPSC issued an order approving an interim increase in revenue of approximately $10.5 million effective April 1, 2019, which remains in effect until the MPSC issues a final order. In May 2019, we reached a settlement with all parties who filed comprehensive revenue requirement, cost allocation, and rate design testimony in our Montana electric rate case. If the MPSC approves the settlement, it will result in an annual increase to electric revenue of approximately $6.5 million (based upon a 9.65% return on equity (ROE) and rate base and capital structure as filed) and an annual decrease in depreciation expense of approximately $9 million. A hearing was held in May 2019 and briefing was completed in late August 2019. In September 2019, the MPSC staff recommended that the MPSC approve and adopt the settlement as filed. We expect a final order from the MPSC during the fourth quarter of 2019.

During the three and nine months ended September 30, 2019, we recognized revenue of approximately $1.6 million and $2.8 million, respectively, and reduced depreciation expense by approximately $2.2 million and $6.7 million, respectively, in the Condensed Consolidated Statements of Income consistent with the proposed settlement above. As of September 30, 2019, we have deferred approximately $1.8 million of the interim revenues. Any difference between interim and final approved rates will be refunded to customers.

Federal Energy Regulatory Commission (FERC) Filing

In May 2019, we submitted a filing with the FERC for our Montana transmission assets. The revenue requirement associated with our Montana FERC assets is reflected in our Montana MPSC-jurisdictional rates as a credit to retail customers. We expect to submit a compliance filing with the MPSC upon resolution of our Montana FERC case adjusting the proposed credit in our Montana retail rates. In June 2019, the FERC issued an order accepting our filing, granting interim rates (subject to refund) effective July 1, 2019, establishing settlement procedures and terminating our related Tax Cuts and Jobs Act filing. A settlement judge has been appointed. We hosted a technical conference regarding the filing attended by intervenors, FERC and MPSC staff in September 2019. We expect to host an additional technical conference and engage in settlement discussions during the fourth quarter of 2019.

Cost Recovery Mechanisms - Montana

Each year we submit an electric and natural gas tracker filing for recovery of supply costs for the 12-month period ended June 30. The MPSC reviews such filings and makes its cost recovery determination based on whether or not our supply procurement activities were prudent. The MPSC approved our electric tracker filings for the 12-month periods ended June 30, 2016 and 2017, on an interim basis. In August 2019, the MPSC established a procedural schedule for adjudication of these dockets with a final order expected in the first quarter of 2020.

Montana Electric Tracker - In 2017, the Montana legislature revised the statute regarding our recovery of electric supply costs. In response, the MPSC approved a new design for our electric tracker in 2018, effective July 1, 2017. The revised electric tracker, or Power Costs and Credits Adjustment Mechanism (PCCAM), established a baseline of power supply costs and tracks the differences between the actual costs and revenues. Variances in supply costs above or below the baseline are allocated 90% to customers and 10% to shareholders, with an annual adjustment. From July 2017 to May 2019, the PCCAM also included a "deadband" which required us to absorb the variances within +/- $4.1 million from the base, with 90% of the variance above or below the deadband collected from or refunded to customers. In 2019, the Montana legislature revised the statute effective May 7, 2019, prohibiting a deadband, allowing 100% recovery of QF purchases, and maintaining the 90% / 10% sharing ratio for other purchases.

The Condensed Consolidated Statements of Income during the nine months ended September 30, 2019, include the recovery of approximately $4.6 million of electric supply costs consistent with the change in statute. Our cumulative under collection of electric supply costs is approximately $25.7 million as of September 30, 2019, and is reflected in regulatory assets in the Condensed Consolidated Balance Sheets. We submitted a filing in September 2019, requesting recovery of costs above the base for the period July 1, 2018 to June 30, 2019, with the under recovery collected over the next 12-month period. The MPSC has not established a procedural schedule in this docket.

Montana QF Power Purchase Cases

Under the Public Utility Regulatory Policies Act (PURPA), electric utilities are required, with certain exceptions, to purchase energy and capacity from independent power producers that are QFs. We track the costs of these purchases through our PCCAM. These purchases are also the subject of proceedings before the MPSC, whose orders are subject to judicial review by Montana state courts.

In May 2016, we filed our biennial update of standard rates for small QFs (3 MW or less). In November 2017, the PSC approved new, lower rates, reduced the maximum contract term from 25 to 15 years, and ordered that it would apply the same 15-year contract term to our future owned and contracted electric supply resources (Symmetry Finding). We sought judicial review with the Montana State District Court (District Court) of the Symmetry Finding. Cypress Creek Renewables, LLC, Vote Solar, and Montana Environmental Information Center, sought judicial review with the District Court of the rates and contract term.

The District Court reversed and modified the MPSC's decisions on rates, contract term, and the Symmetry Finding. We appealed the District Court's order regarding rates and contract term to the Montana Supreme Court. The MPSC did not appeal the District Court's Symmetry Finding. The Montana Supreme Court granted our motion to stay the District Court's decisions regarding rates and contract term. We expect briefing to be completed by the end of October 2019.

The MPSC also issued the same Symmetry Finding in another docket when setting the rates and contract term for a large QF - MT Sun, LLC (MTSun). We, as well as MTSun, sought judicial review of the MPSC's order. The District Court reversed and modified the MPSC's order regarding rates, contract length, and the Symmetry Finding. We appealed the District Court's order to the Montana Supreme Court on the issues of rates and contract length, and the MPSC did not appeal the District Court's reversal of the Symmetry Finding. We expect briefing to be completed in November 2019.

(3) Income Taxes

We compute income tax expense for each quarter based on the estimated annual effective tax rate for the year, adjusted for certain discrete items. Our effective tax rate typically differs from the federal statutory tax rate due to the regulatory impact of flowing through the federal and state tax benefit of repairs deductions, state tax benefit of accelerated tax depreciation deductions (including bonus depreciation when applicable) and production tax credits. The regulatory accounting treatment of these deductions requires immediate income recognition for temporary tax differences of this type, which is referred to as the flow-through method. When the flow-through method of accounting for temporary differences is reflected in regulated revenues, we record deferred income taxes and establish related regulatory assets and liabilities.

The following table summarizes the significant differences in income tax expense based on the differences between our effective tax rate and the federal statutory rate (in thousands):

	Three Months Ended September 30,			
	2019		2018	
Income Before Income Taxes	$ 22,225		$ 27,824	
Income tax calculated at federal statutory rate	4,667	21.0%	5,843	21.0 %
Permanent or flow-through adjustments:				
State income, net of federal provisions	65	0.3	638	2.3
Flow-through repairs deductions	(2,606)	(11.7)	(2,394)	(8.6)
Production tax credits	(1,414)	(6.3)	(1,656)	(6.0)
Amortization of excess deferred income tax	(374)	(1.7)	(418)	(1.5)
Plant and depreciation of flow-through items	(263)	(1.2)	(95)	(0.3)
Prior year permanent return to accrual adjustments	559	2.5	(2,978)	(10.7)
Other, net	(79)	(0.4)	702	2.5
	(4,112)	(18.5)	(6,201)	(22.3)
Income tax expense (benefit)	$ 555	2.5%	$ (358)	(1.3)%

	Nine Months Ended September 30,			
	2019		2018	
Income Before Income Taxes	$ 122,040		$ 135,126	
Income tax calculated at federal statutory rate	25,628	21.0 %	28,376	21.0%
Permanent or flow through adjustments:				
State income, net of federal provisions	1,230	1.0	2,171	1.6
Release of unrecognized tax benefit	(22,825)	(18.7)	—	—
Flow-through repairs deductions	(12,694)	(10.4)	(13,075)	(9.7)
Production tax credits	(7,252)	(5.9)	(8,103)	(6.0)
Plant and depreciation of flow through items	(2,449)	(2.0)	(1,582)	(1.2)
Amortization of excess deferred income tax	(1,939)	(1.6)	(2,045)	(1.5)
Prior year permanent return to accrual adjustments	559	0.4	(2,978)	(2.2)
Share-based compensation	186	0.2	275	0.2
Other, net	(542)	(0.5)	1,619	1.2
	(45,726)	(37.5)	(23,718)	(17.6)
Income tax (benefit) expense	$ (20,098)	(16.5)%	$ 4,658	3.4%

The income tax benefit for the nine months ended September 30, 2019 reflects the release of approximately $22.8 million of unrecognized tax benefits, including approximately $2.7 million of accrued interest and penalties, net of tax, due to the lapse of statutes of limitation in the second quarter of 2019.

Uncertain Tax Positions

We recognize tax positions that meet the more-likely-than-not threshold as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. After the release above, we have unrecognized tax benefits of approximately $35.3 million as of September 30, 2019, including approximately $27.8 million that, if recognized, would impact our effective tax rate. We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statutes of limitation within the next twelve months.

Our policy is to recognize interest and penalties related to uncertain tax positions in income tax expense. As discussed above, during the nine months ended September 30, 2019, we released $2.7 million of accrued interest in the Condensed Consolidated Statements of Income. As of September 30, 2019, we do not have any amounts accrued for the payment of interest and penalties. During the nine months ended September 30, 2018, we recognized $0.9 million of expense for interest and penalties in the Condensed Consolidated Statements of Income. As of December 31, 2018, we had $2.7 million of interest accrued in the Condensed Consolidated Balance Sheets.

Our federal tax returns from 2000 forward remain subject to examination by the Internal Revenue Service.

(4) Comprehensive Income (Loss)

The following tables display the components of Other Comprehensive Income (Loss), after-tax, and the related tax effects (in thousands):

	Three Months Ended					
	September 30, 2019			September 30, 2018		
	Before-Tax Amount	Tax Expense	Net-of-Tax Amount	Before-Tax Amount	Tax Expense	Net-of-Tax Amount
Foreign currency translation adjustment	$ 42	$ —	$ 42	$ (68)	$ —	$ (68)
Reclassification of net income (loss) on derivative instruments	154	(40)	114	153	(40)	113
Other comprehensive income (loss)	$ 196	$ (40)	$ 156	$ 85	$ (40)	$ 45

	Nine Months Ended					
	September 30, 2019			September 30, 2018		
	Before-Tax Amount	Tax Expense	Net-of-Tax Amount	Before-Tax Amount	Tax Expense	Net-of-Tax Amount
Foreign currency translation adjustment	$ 18	$ —	$ 18	$ 113	$ —	$ 113
Reclassification of net income (loss) on derivative instruments	460	(121)	339	460	(121)	339
Other comprehensive income (loss)	$ 478	$ (121)	$ 357	$ 573	$ (121)	$ 452

Balances by classification included within accumulated other comprehensive loss (AOCL) on the Condensed Consolidated Balance Sheets are as follows, net of tax (in thousands):

	September 30, 2019	December 31, 2018
Foreign currency translation	$ 1,466	$ 1,448
Derivative instruments designated as cash flow hedges	(11,294)	(11,633)
Postretirement medical plans	251	251
Accumulated other comprehensive loss	$ (9,577)	$ (9,934)

The following tables display the changes in AOCL by component, net of tax (in thousands):

		Three Months Ended September 30, 2019			
	Affected Line Item in the Condensed Consolidated Statements of Income	Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Pension and Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (11,408)	$ 251	$ 1,424	$ (9,733)
Other comprehensive income before reclassifications		—	—	42	42
Amounts reclassified from AOCL	Interest Expense	114	—	—	114
Net current-period other comprehensive income		114	—	42	156
Ending balance		$ (11,294)	$ 251	$ 1,466	$ (9,577)

	Affected Line Item in the Condensed Consolidated Statements of Income	Three Months Ended September 30, 2018 Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Pension and Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (11,905)	$ 38	$ 1,359	$ (10,508)
Other comprehensive loss before reclassifications		—	—	(68)	(68)
Amounts reclassified from AOCL	Interest Expense	113	—	—	113
Net current-period other comprehensive income (loss)		113	—	(68)	45
Ending balance		$ (11,792)	$ 38	$ 1,291	$ (10,463)

	Affected Line Item in the Condensed Consolidated Statements of Income	Nine Months Ended September 30, 2019 Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Pension and Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (11,633)	$ 251	$ 1,448	(9,934)
Other comprehensive income before reclassifications		—	—	18	18
Amounts reclassified from AOCL	Interest Expense	339	—	—	339
Net current-period other comprehensive income		339	—	18	357
Ending balance		$ (11,294)	$ 251	$ 1,466	$ (9,577)

	Affected Line Item in the Condensed Consolidated Statements of Income	Nine Months Ended September 30, 2018 Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Pension and Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (9,981)	$ 31	$ 1,178	$ (8,772)
Other comprehensive income before reclassifications		—	—	113	113
Amounts reclassified from AOCL	Interest Expense	339	—	—	339
Net current-period other comprehensive income		339	—	113	452
Reclassification of certain tax effects from AOCL		$ (2,150)	$ 7	$ —	(2,143)
Ending balance		$ (11,792)	$ 38	$ 1,291	$ (10,463)

(5) Financing Activities

In June 2019, we priced $150 million aggregate principal amount of Montana First Mortgage Bonds, at a fixed interest rate of 3.98% maturing in 2049. We issued $50 million of these bonds in June 2019 and the remaining $100 million of these bonds in September 2019 in transactions exempt from the registration requirements of the Securities Act of 1933, as amended. Proceeds were used to repay a portion of our outstanding borrowings under our revolving credit facilities and for other general corporate purposes. The bonds are secured by our electric and natural gas assets in Montana.

(6) Segment Information

Our reportable business segments are primarily engaged in the electric and natural gas business. The remainder of our operations are presented as other, which primarily consists of unallocated corporate costs and unregulated activity.

We evaluate the performance of these segments based on gross margin. The accounting policies of the operating segments are the same as the parent except that the parent allocates some of its operating expenses to the operating segments according to a methodology designed by management for internal reporting purposes and involves estimates and assumptions.

Financial data for the business segments are as follows (in thousands):

Three Months Ended September 30, 2019	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 241,237	$ 33,599	$ —	$ —	$ 274,836
Cost of sales	58,768	5,459	—	—	64,227
Gross margin	182,469	28,140	—	—	210,609
Operating, general and administrative	57,433	18,830	735	—	76,998
Property and other taxes	34,731	9,355	3	—	44,089
Depreciation and depletion	35,824	7,342	—	—	43,166
Operating income (loss)	54,481	(7,387)	(738)	—	46,356
Interest expense	(19,481)	(1,588)	(2,653)	—	(23,722)
Other (expense) income	(677)	(344)	612	—	(409)
Income tax (expense) benefit	(1,415)	(232)	1,092	—	(555)
Net income (loss)	$ 32,908	$ (9,551)	$ (1,687)	$ —	$ 21,670
Total assets	$ 4,632,077	$ 1,173,513	$ 4,590	$ —	$ 5,810,180
Capital expenditures	$ 70,063	$ 25,784	$ —	$ —	$ 95,847

Three Months Ended September 30, 2018	Electric	Gas	Other	Eliminations	Total
Operating revenues	245,159	$ 34,715	$ —	$ —	$ 279,874
Cost of sales	66,512	5,735	—	—	72,247
Gross margin	178,647	28,980	—	—	207,627
Operating, general and administrative	54,009	19,146	632	—	73,787
Property and other taxes	33,452	8,997	2	—	42,451
Depreciation and depletion	36,202	7,377	2	—	43,581
Operating income (loss)	54,984	(6,540)	(636)	—	47,808
Interest expense	(19,070)	(1,436)	(1,529)	—	(22,035)
Other income	926	436	689	—	2,051
Income tax (expense) benefit	(2,183)	362	2,179	—	358
Net income (loss)	$ 34,657	$ (7,178)	$ 703	$ —	$ 28,182
Total assets	$ 4,408,464	$ 1,076,341	$ 15,293	$ —	$ 5,500,098
Capital expenditures	$ 60,062	$ 16,887	$ —	$ —	$ 76,949

Nine Months Ended September 30, 2019	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 733,933	$ 195,842	$ —	$ —	$ 929,775
Cost of sales	178,423	57,283	—	—	235,706
Gross margin	555,510	138,559	—	—	694,069
Operating, general and administrative	174,544	60,803	3,569	—	238,916
Property and other taxes	104,612	28,569	7	—	133,188
Depreciation and depletion	107,595	22,171	—	—	129,766
Operating income (loss)	168,759	27,016	(3,576)	—	192,199
Interest expense	(58,301)	(4,599)	(8,123)	—	(71,023)
Other (expense) income	(1,458)	(874)	3,196	—	864
Income tax (expense) benefit	(4,937)	493	24,542	—	20,098
Net income	$ 104,063	$ 22,036	$ 16,039	$ —	$ 142,138
Total assets	4,632,077	1,173,513	4,590	—	5,810,180
Capital expenditures	186,155	56,719	—	—	242,874

Nine Months Ended September 30, 2018	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 693,256	$ 189,937	$ —	$ —	$ 883,193
Cost of sales	143,398	57,116	—	—	200,514
Gross margin	549,858	132,821	—	—	682,679
Operating, general and administrative	161,551	60,015	400	—	221,966
Property and other taxes	100,825	27,475	6	—	128,306
Depreciation and depletion	108,494	22,365	18	—	130,877
Operating income (loss)	178,988	22,966	(424)	—	201,530
Interest expense	(58,908)	(4,451)	(4,843)	—	(68,202)
Other income	1,364	353	81	—	1,798
Income tax (expense) benefit	(5,330)	(1,372)	2,044	—	(4,658)
Net income (loss)	$ 116,114	$ 17,496	$ (3,142)	$ —	$ 130,468
Total assets	$ 4,408,464	$ 1,076,341	$ 15,293	$ —	5,500,098
Capital expenditures	$ 155,804	$ 37,601	$ —	$ —	193,405

(7) Revenue from Contracts with Customers

Nature of Goods and Services

We provide retail electric and natural gas services to three primary customer classes. Our largest customer class consists of residential customers, which include single private dwellings and individual apartments. Our commercial customers consist primarily of main street businesses, and our industrial customers consist primarily of manufacturing and processing businesses that turn raw materials into products.

Electric Segment - Our regulated electric utility business primarily provides generation, transmission, and distribution services to our customers in our Montana and South Dakota jurisdictions. We recognize revenue when electricity is delivered to the customer. Payments on our tariff based sales are generally due 20-30 days after the billing date.

Natural Gas Segment - Our regulated natural gas utility business primarily provides production, storage, transmission, and distribution services to our customers in our Montana, South Dakota, and Nebraska jurisdictions. We recognize revenue when natural gas is delivered to the customer. Payments on our tariff based sales are generally due 20-30 days after the billing date.

Disaggregation of Revenue

The following tables disaggregate our revenue by major source and customer class (in millions):

	Three Months Ended					
	September 30, 2019			September 30, 2018		
	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Montana	$ 68.4	$ 8.9	$ 77.3	$ 67.6	$ 9.4	$ 77.0
South Dakota	16.0	1.7	17.7	16.5	1.7	18.2
Nebraska	—	1.8	1.8	—	1.9	1.9
Residential	**84.4**	**12.4**	**96.8**	**84.1**	**13.0**	**97.1**
Montana	87.7	5.5	93.2	85.8	5.5	91.3
South Dakota	26.3	1.3	27.6	24.4	0.9	25.3
Nebraska	—	0.9	0.9	—	0.9	0.9
Commercial	**114.0**	**7.7**	**121.7**	**110.2**	**7.3**	**117.5**
Industrial	10.6	0.1	10.7	9.8	0.1	9.9
Lighting, Governmental, Irrigation, and Interdepartmental	12.4	0.1	12.5	11.4	0.1	11.5
Total Customer Revenues	**221.4**	**20.3**	**241.7**	**215.5**	**20.5**	**236.0**
Other Tariff and Contract Based Revenues	15.3	7.7	**23.0**	13.0	8.5	**21.5**
Total Revenue from Contracts with Customers	**236.7**	**28.0**	**264.7**	**228.5**	**29.0**	**257.5**
Regulatory amortization	4.5	5.6	10.1	16.7	5.7	22.4
Total Revenues	**$ 241.2**	**$ 33.6**	**$ 274.8**	**$ 245.2**	**$ 34.7**	**$ 279.9**

	Nine Months Ended					
	September 30, 2019			September 30, 2018		
	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Montana	$ 225.4	$ 73.3	$ 298.7	$ 214.3	$ 67.9	$ 282.2
South Dakota	47.4	20.4	67.8	49.6	18.7	68.3
Nebraska	—	15.7	15.7	—	18.3	18.3
Residential	**272.8**	**109.4**	**382.2**	**263.9**	**104.9**	**368.8**
Montana	257.3	38.0	295.3	249.1	34.9	284.0
South Dakota	71.2	14.1	85.3	70.7	12.4	83.1
Nebraska	—	8.3	8.3	—	9.4	9.4
Commercial	**328.5**	**60.4**	**388.9**	**319.8**	**56.7**	**376.5**
Industrial	32.4	0.7	33.1	31.3	0.8	32.1
Lighting, Governmental, Irrigation, and Interdepartmental	25.2	0.6	25.8	23.5	0.7	24.2
Total Customer Revenues	**658.9**	**171.1**	**830.0**	**638.5**	**163.1**	**801.6**
Other Tariff and Contract Based Revenues	46.5	26.6	**73.1**	48.6	29.5	**78.1**
Total Revenue from Contracts with Customers	**705.4**	**197.7**	**903.1**	**687.1**	**192.6**	**879.7**
Regulatory amortization	28.5	(1.9)	26.6	6.2	(2.7)	3.5
Total Revenues	**$ 733.9**	**$ 195.8**	**$ 929.7**	**$ 693.3**	**$ 189.9**	**$ 883.2**

(8) Earnings Per Share

Basic earnings per share are computed by dividing earnings applicable to common stock by the weighted average number of common shares outstanding for the period. Diluted earnings per share reflect the potential dilution of common stock equivalent shares that could occur if unvested shares were to vest. Common stock equivalent shares are calculated using the treasury stock method, as applicable. The dilutive effect is computed by dividing earnings applicable to common stock by the weighted average number of common shares outstanding plus the effect of the outstanding unvested restricted stock and performance share awards. Average shares used in computing the basic and diluted earnings per share are as follows:

	Three Months Ended	
	September 30, 2019	September 30, 2018
Basic computation	50,443,866	50,317,813
Dilutive effect of:		
Performance share awards (1)	335,371	142,730
Diluted computation	50,779,237	50,460,543

	Nine Months Ended	
	September 30, 2019	September 30, 2018
Basic computation	50,422,028	49,871,042
Dilutive effect of:		
Performance share awards (1)	334,002	139,371
Diluted computation	50,756,030	50,010,413

(1) Performance share awards are included in diluted weighted average number of shares outstanding based upon what would be issued if the end of the most recent reporting period was the end of the term of the award.

(9) Employee Benefit Plans

We sponsor and/or contribute to pension and postretirement health care and life insurance benefit plans for eligible employees. Net periodic benefit cost (income) for our pension and other postretirement plans consists of the following (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2019	2018	2019	2018
Components of Net Periodic Benefit Cost (Income)				
Service cost	$ 2,409	$ 2,944	$ 82	$ 100
Interest cost	6,622	6,105	152	145
Expected return on plan assets	(6,360)	(7,051)	(217)	(239)
Amortization of prior service cost (credit)	1,636	1	(471)	(471)
Recognized actuarial loss (gain)	—	1,090	(24)	(19)
Plan settlements	715	—	—	—
Net Periodic Benefit Cost (Income)	$ 5,022	$ 3,089	$ (478)	$ (484)

	Pension Benefits		Other Postretirement Benefits	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Components of Net Periodic Benefit Cost (Income)				
Service cost	$ 7,228	$ 8,832	$ 248	$ 299
Interest cost	19,866	18,315	457	434
Expected return on plan assets	(19,082)	(21,155)	(652)	(716)
Amortization of prior service cost	4,908	3	(1,412)	(1,412)
Recognized actuarial loss (gain)	—	3,270	(72)	(59)
Plan settlements	715	—	—	—
Net Periodic Benefit Cost (Income)	$ 13,635	$ 9,265	$ (1,431)	$ (1,454)

We have contributed $7.2 million to our pension plans during the nine months ended September 30, 2019. We expect to contribute an additional $3 million to $5 million to our pension plans during the fourth quarter of 2019.

(10) Commitments and Contingencies

ENVIRONMENTAL LIABILITIES AND REGULATION

Environmental Matters

The operation of electric generating, transmission and distribution facilities, and gas gathering, storage, transportation and distribution facilities, along with the development (involving site selection, environmental assessments, and permitting) and construction of these assets, are subject to extensive federal, state, and local environmental and land use laws and regulations. Our activities involve compliance with diverse laws and regulations that address emissions and impacts to the environment, including air and water, protection of natural resources, avian and wildlife. We monitor federal, state, and local environmental initiatives to determine potential impacts on our financial results. As new laws or regulations are implemented, our policy is to assess their applicability and implement the necessary modifications to our facilities or their operation to maintain ongoing compliance.

Our environmental exposure includes a number of components, including remediation expenses related to the cleanup of current or former properties, and costs to comply with changing environmental regulations related to our operations. At present, our environmental reserve, which relates primarily to the remediation of former manufactured gas plant sites owned by us, is estimated to range between $26.6 million to $34.6 million. As of September 30, 2019, we have a reserve of approximately $28.7 million, which has not been discounted. Environmental costs are recorded when it is probable we are liable for the remediation and we can reasonably estimate the liability. We use a combination of site investigations and monitoring to formulate an estimate of environmental remediation costs for specific sites. Our monitoring procedures and development of actual remediation plans depend not only on site specific information but also on coordination with the different environmental regulatory agencies in our respective jurisdictions; therefore, while remediation exposure exists, it may be many years before costs are incurred.

Over time, as costs become determinable, we may seek authorization to recover such costs in rates or seek insurance reimbursement as available and applicable; therefore, although we cannot guarantee regulatory recovery, we do not expect these costs to have a material effect on our consolidated financial position or results of operations.

Manufactured Gas Plants - Approximately $21.7 million of our environmental reserve accrual is related to manufactured gas plants. A formerly operated manufactured gas plant located in Aberdeen, South Dakota, has been identified on the Federal Comprehensive Environmental Response, Compensation, and Liability Information System list as contaminated with coal tar residue. We are currently conducting feasibility studies, implementing remedial actions pursuant to work plans approved by the South Dakota Department of Environment and Natural Resources, and conducting ongoing monitoring and operation and maintenance activities. As of September 30, 2019, the reserve for remediation costs at this site is approximately $8.0 million, and we estimate that approximately $3.2 million of this amount will be incurred during the next five years.

We also own sites in North Platte, Kearney, and Grand Island, Nebraska on which former manufactured gas facilities were located. We are currently working independently to fully characterize the nature and extent of potential impacts associated with these Nebraska sites. Our reserve estimate includes assumptions for site assessment and remedial action work. At present, we cannot determine with a reasonable degree of certainty the nature and timing of any risk-based remedial action at our Nebraska locations.

In addition, we own or have responsibility for sites in Butte, Missoula, and Helena, Montana on which former manufactured gas plants were located. The Butte and Helena sites, both listed as high priority sites on Montana's state superfund list, were placed into the Montana Department of Environmental Quality (MDEQ) voluntary remediation program for cleanup due to soil and groundwater impacts. Soil and coal tar were removed at the sites in accordance with the MDEQ requirements. Groundwater monitoring is conducted semiannually at both sites. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of additional remedial actions and/or investigations, if any, at the Butte site. In August 2016, the MDEQ sent us a Notice of Potential Liability and Request for Remedial Action regarding the Helena site. In October 2019, we submitted a third revised Remedial Investigation Work Plan (RIWP) for the Helena site addressing MDEQ comments on previously submitted drafts of the RIWP. The RIWP requires additional investigation including vapor intrusion and investigation of potential contamination from transformers and treated poles. MDEQ is expected to complete its review of the RIWP by the fourth quarter of 2019.

An investigation conducted at the Missoula site did not require remediation activities, but required preparation of a groundwater monitoring plan. Monitoring wells were installed and groundwater is monitored semiannually. At the request of Missoula Valley Water Quality District (MVWQD), a draft risk assessment was prepared for the Missoula site and presented to the MVWQD. We and the MVWQD agreed additional site investigation work is appropriate. Analytical results from an October 2016 sampling exceeded the Montana Maximum Contaminant Level for benzene and/or total cyanide in certain monitoring wells. These results were forwarded to MVWQD which shared the same with the MDEQ. MDEQ requested that MVWQD file a formal complaint with MDEQ's Enforcement Division, which MVWQD filed in July 2017. On April 2, 2019, MDEQ requested our participation at a stakeholders' meeting for the Missoula site. At the meeting, MDEQ indicated they expect to proceed in listing the site as a Montana superfund site. After researching historical ownership we have identified another potentially responsible party with whom we have initiated communications regarding the site. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of risk-based remedial action, if any, at the Missoula site.

Global Climate Change - National and international actions have been initiated to address global climate change and the contribution of greenhouse gas (GHG) including, most significantly, carbon dioxide (CO_2). These actions include legislative proposals, Executive and Environmental Protection Agency (EPA) actions at the federal level, actions at the state level, and private party litigation relating to GHG emissions. Coal-fired plants have come under particular scrutiny due to their level of GHG emissions. We have joint ownership interests in four coal-fired electric generating plants, all of which are operated by other companies. We are responsible for our proportionate share of the capital and operating costs while being entitled to our proportionate share of the power generated.

While numerous bills have been introduced that address climate change from different perspectives, including through direct regulation of GHG emissions, the establishment of cap and trade programs and the establishment of federal renewable portfolio standards, Congress has not passed any federal climate change legislation and we cannot predict the timing or form of any potential legislation. In the absence of such legislation, EPA is presently regulating new and existing sources of GHG emissions through regulations. On June 19, 2019, EPA finalized the Affordable Clean Energy Rule (ACE). ACE repeals the 2015 Clean Power Plan (CPP) in regulating GHG emissions from coal-fired plants. Generally, ACE will provide more regulatory flexibility to individual states and likely will not reduce CO_2 emissions as much as the CPP. Numerous parties, including us, filed petitions for review and reconsideration of the CPP. Those CPP proceedings were dismissed as moot by the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) on September 17, 2019.

Under the ACE, states must establish unit-specific standards that reflect emissions achievable through heat rate improvements, which EPA designated as the best system of emissions reduction, and if the state chooses, take into account the remaining useful life of the unit and other source specific factors. States generally have three years to submit the standards to EPA and coal-fired plants will have two additional years to comply with the standards. The ACE became effective on September 6, 2019, and various challenges to it are pending in the D.C. Circuit.

We cannot predict whether or how ACE will be applied to our plants, including actions taken by the relevant state authorities. In addition, it is unclear how pending or future litigation relating to GHG matters will impact us. As GHG regulations are implemented, it would result in additional compliance costs that could affect our future results of operations and financial position if such costs are not recovered through regulated rates. We will continue working with federal and state regulatory authorities, other utilities, and stakeholders to seek relief from any GHG regulations that, in our view, disproportionately impact customers in our region.

Future additional environmental requirements could cause us to incur material costs of compliance, increase our costs of procuring electricity, decrease transmission revenue and impact cost recovery. Technology to efficiently capture, remove and/or sequester such GHG emissions may not be available within a timeframe consistent with the implementation of any such requirements. Physical impacts of climate change also may present potential risks for severe weather, such as droughts, fires, floods, ice storms and tornadoes, in the locations where we operate or have interests. These potential risks may impact costs for electric and natural gas supply and maintenance of generation, distribution, and transmission facilities.

Clean Air Act Rules and Associated Emission Control Equipment Expenditures **-** The EPA has proposed or issued a number of rules under different provisions of the Clean Air Act that could require the installation of emission control equipment at the generation plants in which we have joint ownership.

On January 10, 2017, the EPA published amendments to the requirements under the Clean Air Act for state plans for protection of visibility. Among other things, these amendments revised the process and requirements for the state implementation plans and extended the due date for the next periodic comprehensive regional haze state implementation plan revisions from 2018 to 2021. Therefore, by 2021, Montana, or EPA, must develop a revised plan that demonstrates reasonable progress toward eliminating man-made emissions of visibility impairing pollutants, which could impact Colstrip Unit 4. In March 2017, we filed a Petition for Review of these amendments with the D.C. Circuit, which was consolidated with other petitions challenging the final rule. The D.C. Circuit has granted EPA’s request to hold the case in abeyance while EPA considers further administrative action to revisit the rule.

Jointly Owned Plants **-** We have joint ownership in generation plants located in South Dakota, North Dakota, Iowa, and Montana that are or may become subject to the various regulations discussed above that have been issued or proposed. Regarding the ACE, as discussed above, we cannot predict the impact of the ACE on us until the state plans are adopted and any judicial reviews are completed.

Other **-** We continue to manage equipment containing polychlorinated biphenyl (PCB) oil in accordance with the EPA's Toxic Substance Control Act regulations. We will continue to use certain PCB-contaminated equipment for its remaining useful life and will, thereafter, dispose of the equipment according to pertinent regulations that govern the use and disposal of such equipment.

We routinely engage the services of a third-party environmental consulting firm to assist in performing a comprehensive evaluation of our environmental reserve. Based upon information available at this time, we believe that the current environmental reserve properly reflects our remediation exposure for the sites currently and previously owned by us. The portion of our environmental reserve applicable to site remediation may be subject to change as a result of the following uncertainties:

- We may not know all sites for which we are alleged or will be found to be responsible for remediation; and
- Absent performance of certain testing at sites where we have been identified as responsible for remediation, we cannot estimate with a reasonable degree of certainty the total costs of remediation.

LEGAL PROCEEDINGS

Pacific Northwest Solar Litigation

Pacific Northwest Solar, LLC (PNWS) is a solar QF developer seeking to construct small solar facilities in Montana. We began negotiating with PNWS in early 2016 to purchase the output from 21 of its proposed facilities pursuant to our standard QF-1 Tariff, which is applicable to projects no larger than 3 MWs.

On June 16, 2016, however, the MPSC suspended the availability of the QF-1 Tariff standard rates for that category of solar projects, which included the projects proposed by PNWS. The MPSC exempted from the suspension any projects for which a QF had both submitted a signed power purchase agreement and had executed an interconnection agreement with us by June 16, 2016. Although we had signed four power purchase agreements with PNWS as of that date, we had not entered into interconnection agreements with PNWS for any of those projects. As a result, none of the PNWS projects in Montana qualified for the exemption.

In November 2016, PNWS sued us in state court seeking unspecified damages for breach of contract and a judicial declaration that some or all of the 21 proposed power purchase agreements it had proposed to us were in effect despite the MPSC's Order. We removed the state lawsuit to the United States District Court for the District of Montana (Court).

PNWS also requested the MPSC to exempt its projects from the tariff suspension and allow those projects to receive the QF-1 tariff rate that had been in effect prior to the suspension. We joined in PNWS's request for relief with respect to four of the projects, but the MPSC did not grant any of the relief requested by PNWS or us.

In August 2017, pursuant to a non-monetary, partial settlement with us, PNWS amended its original complaint to limit its claims for enforcement and/or damages to only four of the 21 power purchase agreements. As a result, the amount of damages sought by the plaintiff was reduced to approximately $8 million for the alleged breach of the four power purchase agreements. We participated in an unsuccessful mediation on January 24, 2019 and there have been no settlement negotiations since then.

A jury trial was scheduled to begin on October 8, 2019 to address PNWS' remaining breach of contract claims and its request for a declaratory judgment. On October 3, 2019, however, PNWS filed a motion asking the Court to hold another pretrial conference clarifying some of its evidentiary rulings and a second motion asking the Court to issue a final pretrial order more clearly defining the legal and factual issues remaining for trial. On October 4, 2019, the Court denied both motions for procedural irregularities, gave PNWS leave to correct and refile them (which PNWS has since done), and vacated the trial date so that the issues raised in the two motions could be addressed at a hearing. A hearing and / or rescheduled trial date has not been established by the Court.

We dispute the remaining claims in PNWS' lawsuit and will continue to vigorously defend against them. We cannot currently predict an outcome in this litigation. If the plaintiff prevails and obtains damages for a breach of contract, we may seek to recover those damages in rates from customers. We cannot predict the outcome of any such effort.

State of Montana - Riverbed Rents

On April 1, 2016, the State of Montana (State) filed a complaint on remand (the State's Complaint) with the Montana First Judicial District Court (State District Court), naming us, along with Talen Montana, LLC (Talen) as defendants. The State claimed it owns the riverbeds underlying 10 of our hydroelectric facilities (dams, along with reservoirs and tailraces) on the Missouri, Madison and Clark Fork Rivers, and seeks rents for Talen's and our use and occupancy of such lands. The facilities at issue include the Hebgen, Madison, Hauser, Holter, Black Eagle, Rainbow, Cochrane, Ryan, and Morony facilities on the Missouri and Madison Rivers and the Thompson Falls facility on the Clark Fork River. We acquired these facilities from Talen in November 2014.

The litigation has a long prior history, which culminated with a 2012 decision by the United States Supreme Court holding that the Montana Supreme Court erred in not considering a segment-by-segment approach to determine navigability and relying on present day recreational use of the rivers. It also held that what it referred to as the Great Falls Reach "at least from the head of the first waterfall to the foot of the last" was not navigable for title purposes, and thus the State did not own the riverbeds in that segment. The United States Supreme Court remanded the case to the Montana Supreme Court for further proceedings not inconsistent with its opinion. Following the 2012 remand, the case laid dormant for four years until the State's Complaint was filed with the State District Court. On April 20, 2016, we removed the case from State District Court to the United States District Court for the District of Montana (Federal District Court). The State filed a motion to remand. Following briefing and argument, on October 10, 2017, the Federal District Court entered an order denying the State’s motion.

Because the State's Complaint included a claim that the State owned the riverbeds in the Great Falls Reach, on October 16, 2017, we and Talen renewed our earlier filed motions seeking to dismiss the portion of the State's Complaint concerning the Great Falls Reach in light of the United States Supreme Court’s decision. On August 1, 2018, the Federal District Court granted the motions to dismiss the State’s Complaint as it pertains to approximately 8.2 miles of riverbed between Black Eagle Falls and the Great Falls. In particular, the dismissal pertains to the Black Eagle Dam, Rainbow Dam and reservoir, Cochrane Dam and reservoir, and Ryan Dam and reservoir. This leaves a portion of the Black Eagle reservoir and Morony Dam and reservoir at issue. While the dismissal of these four facilities is subject to appeal, that appeal would not likely occur until after judgment in the case. We and Talen filed our respective answers to the State’s Complaint on August 22, 2018. Additionally, we and Talen filed a motion to join the United States as a defendant to the litigation. The Federal District Court granted the motion on February 12, 2019, and has ordered the State to name the United States as a party defendant under the Federal Quiet Title Act by October 31, 2019.

We dispute the State’s claims and intend to vigorously defend the lawsuit. This matter is still at its early stages, and we cannot predict an outcome. If the Federal District Court determines the riverbeds are navigable under the remaining six facilities that were not dismissed and if it calculates damages as the State District Court did in 2008, we estimate the annual rents could be approximately $3.8 million commencing when we acquired the facilities in November 2014. We anticipate that any obligation to pay the State rent for use and occupancy of the riverbeds would be recoverable in rates from customers, although there can be no assurances that the MPSC would approve any such recovery.

Other Legal Proceedings

We are also subject to various other legal proceedings, governmental audits and claims that arise in the ordinary course of business. In the opinion of management, the amount of ultimate liability with respect to these other actions will not materially affect our financial position, results of operations, or cash flows.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and natural gas to approximately 726,400 customers in Montana, South Dakota and Nebraska. For a discussion of NorthWestern's business strategy, see Management's Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report on Form 10-K for the year ended December 31, 2018.

We are working to deliver safe, reliable and innovative energy solutions that create value for our customers, communities, employees and investors. This includes bridging our history as a regulated utility safely providing low-cost and reliable service with our future as a globally-aware company offering a broader array of services performed by highly-adaptable and skilled employees. We seek to deliver value to our customers by providing high reliability and customer service, and an environmentally sustainable generation mix at an affordable price. We are focused on delivering long-term shareholder value by continuing to invest in our system including:

- Infrastructure investment focused on a stronger and smarter grid to improve the customer experience, while enhancing grid reliability and safety. This includes automation in distribution and substations that enables the use of changing technology.
- Integrating supply resources that balance reliability, cost, capacity, and sustainability considerations with more predictable long-term commodity prices.
- Continually improving our operating efficiency. Financial discipline is essential to earning our authorized return on invested capital and maintaining a strong balance sheet, stable cash flows, and quality credit ratings.

We expect to pursue these investment opportunities and manage our business in a manner that allows us to be flexible in adjusting to changing economic conditions by adjusting the timing and scale of the projects.

As you read this discussion and analysis, refer to our Condensed Consolidated Statements of Income, which present the results of our operations for the three and nine months ended September 30, 2019 and 2018.

HOW WE PERFORMED AGAINST OUR THIRD QUARTER 2018 RESULTS

	Three months ended September 30, 2019 vs. 2018		
	Income Before Income Taxes	Income Tax Expense	Net Income
Third Quarter 2018	$ 27.8	$ 0.4	$ 28.2
Items increasing (decreasing) net income:			
Higher operating, general, and administrative expenses	(6.2)	1.6	(4.6)
Lower electric retail volumes	(1.9)	0.5	(1.4)
Lower Montana electric transmission revenue	(1.8)	0.5	(1.3)
Lower Montana gas rates	(0.4)	0.1	(0.3)
Higher revenue absent the 2018 impacts of the Tax Cuts and Jobs Act	3.0	(0.8)	2.2
Higher Montana electric supply cost recovery	1.9	(0.5)	1.4
Higher Montana electric rates, subject to refund	1.6	(0.4)	1.2
Lower depreciation and depletion	0.4	(0.1)	0.3
Higher gas retail volumes	0.3	(0.1)	0.2
Other	(2.5)	(1.7)	(4.2)
Third Quarter 2019	$ 22.2	$ (0.5)	$ 21.7
Change in Net Income			$ (6.5)

Consolidated net income for the three months ended September 30, 2019 was $21.7 million as compared with $28.2 million for the same period in 2018. This decrease was primarily due to higher operating, general and administrative costs, lower transmission revenue and mild weather, offset in part by the impacts of the Tax Cuts and Jobs Act settlement in 2018, recovery of Montana electric supply costs, and an increase in Montana electric retail rates, subject to refund.

Following is a brief overview of significant items for 2019.

SIGNIFICANT TRENDS AND REGULATION

Montana General Electric Rate Case

In September 2018, we filed an electric rate case with the MPSC requesting an annual increase to electric rates of approximately $34.9 million. The MPSC issued an order approving an interim increase in revenue of approximately $10.5 million effective April 1, 2019, which remains in effect until the MPSC issues a final order. In May 2019, we reached a settlement including all parties who filed comprehensive revenue requirement, cost allocation, and rate design testimony in our Montana electric rate case. If the MPSC approves the settlement, it will result in an annual increase to electric revenue of approximately $6.5 million (based upon a 9.65% ROE and rate base and capital structure as filed) and an annual decrease in depreciation expense of approximately $9 million. A hearing was held in May 2019 and briefing was complete in late August 2019. In September 2019, the MPSC staff recommended that the MPSC approve and adopt the settlement as filed. We expect a final order from the MPSC during the fourth quarter of 2019.

During the three and nine months ended September 30, 2019, we recognized revenue of approximately $1.6 million and $2.8 million, respectively, and reduced depreciation expense by approximately $2.2 million and $6.7 million, respectively, in the Condensed Consolidated Statement of Income consistent with the proposed settlement above. As of September 30, 2019, we have deferred approximately $1.8 million of the interim revenues. Any difference between interim and final approved rates will be refunded to customers.

FERC Filing

In May 2019, we submitted a filing with the FERC for our Montana transmission assets. The revenue requirement associated with our Montana FERC assets is reflected in our Montana MPSC-jurisdictional rates as a credit to retail customers. We expect to submit a compliance filing with the MPSC upon resolution of our Montana FERC case adjusting the proposed credit in our Montana retail rates. In June 2019, the FERC issued an order accepting our filing, granting interim rates (subject to refund) effective July 1, 2019, establishing settlement procedures and terminating our related Tax Cuts and Jobs Act filing. A settlement judge has been appointed. We hosted a technical conference regarding the filing attended by intervenors, FERC and MPSC staff in September 2019. We expect to host an additional technical conference and engage in settlement discussions during the fourth quarter of 2019.

Montana Electric Tracker

In 2017, the Montana legislature revised the statute regarding our recovery of electric supply costs. In response, the MPSC approved a new design for our electric tracker in 2018, effective July 1, 2017. The revised electric tracker, or PCCAM, established a baseline of power supply costs and tracks the differences between the actual costs and revenues. Variances in supply costs above or below the baseline are allocated 90% to customers and 10% to shareholders, with an annual adjustment. From July 2017 to May 2019, the PCCAM also included a "deadband" which required us to absorb the variances within +/- $4.1 million from the base, with 90% of the variance above or below the deadband collected from or refunded to customers. In 2019, the Montana legislature revised the statute effective May 7, 2019, prohibiting a deadband, allowing 100% recovery of QF purchases, and maintaining the 90% / 10% sharing ratio for other purchases.

The Condensed Consolidated Statements of Income during the nine months ended September 30, 2019, include the recovery of approximately $4.6 million of electric supply costs consistent with the change in statute. Our cumulative under collection of electric supply costs is approximately $25.7 million as of September 30, 2019, and is reflected in regulatory assets in the Condensed Consolidated Balance Sheets. We submitted a filing in September 2019 requesting recovery of costs above the base for the period July 1, 2018 to June 30, 2019 with the under recovery collected over the next 12-month period. We began collecting the requested rate increase October 1, 2019. The MPSC has not established a procedural schedule in this docket.

Electric Supply Resource Plans

Montana - In March 2019, we issued our draft 2019 Electricity Supply Resource Procurement Plan (Montana Resource Plan). In August 2019, we submitted the final 2019 Montana Resource Plan, including responses to public comments. The Montana Resource Plan supports the goal of developing resources that will address the changing energy landscape in Montana to meet our customers' electric energy needs in a reliable and affordable manner.

We are currently 630 MW short of our peak needs, which we procure in the market. We forecast that our energy portfolio will be 725 MW short by 2025, considering expiring contracts and a modest increase in customer demand. Based on our customers' future energy resource needs as identified in the Montana Resource Plan, we expect to solicit competitive proposals in late 2019 for peaking capacity to be available for commercial operation in early 2023. We expect to use an independent evaluator to administer the solicitation process and evaluate proposals. We expect the process will be repeated in subsequent years to provide a resource-adequate energy and capacity portfolio by 2025.

The proposed solicitation process will allow us to consider a wide variety of resource options. These options include power purchase agreements and owned energy resources comprised of different structures, terms and technologies that are cost-effective resources. The staged approach is designed to allow for incremental steps through time with opportunities for different resource type of new technologies while also building a reliable portfolio to meet local and regional conditions and minimizing customer impacts.

South Dakota - In April 2019, we issued a request for proposals for 60 MW of flexible capacity resources to begin serving South Dakota customers by the end of 2021. As a result of a competitive solicitation process, we expect to own a natural gas fired reciprocating internal combustion engine at Huron, South Dakota. Dependent upon selection of manufacturer, we anticipate 55 - 60 MW to be online by late 2021 at a total investment of approximately $80 million. The selected proposal is subject to the execution of construction contracts and obtaining the applicable environmental and construction related permits.

Colstrip Coal Supply

Colstrip Units 3 and 4 are supplied with fuel from adjacent coal reserves under coal supply and transportation agreements with Western Energy Company (WeCo), which are effective through December 31, 2019. WeCo filed for Chapter 11 bankruptcy protection in October 2018. After receiving no qualified bids at a January 2019 auction, a lenders group acquired the core assets, which included the mine adjacent to Colstrip in March 2019. Immediately prior to that acquisition, WeCo assumed the existing coal supply and transportation agreements, which were assigned to the lenders group, which is now known as Westmoreland Rosebud Mining, LLC (WRM). We are working with WRM and the other joint owners of Colstrip to negotiate a new coal supply agreement, which may have higher costs than the existing coal supply agreement. Our Montana Resource Plan indicates Colstrip will continue to play a significant role in providing us a cost-effective and reliable supply portfolio.

RESULTS OF OPERATIONS

Our consolidated results include the results of our divisions and subsidiaries constituting each of our business segments. The overall consolidated discussion is followed by a detailed discussion of gross margin by segment.

Non-GAAP Financial Measure

The following discussion includes financial information prepared in accordance with GAAP, as well as another financial measure, Gross Margin, that is considered a “non-GAAP financial measure.” Generally, a non-GAAP financial measure is a numerical measure of a company’s financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. We define Gross Margin as Revenues less Cost of Sales as presented in our Condensed Consolidated Statements of Income.

Management believes that Gross Margin provides a useful measure for investors and other financial statement users to analyze our financial performance in that it excludes the effect on total revenues caused by volatility in energy costs and associated regulatory mechanisms. This information is intended to enhance an investor's overall understanding of results. Under our various state regulatory mechanisms, as detailed below, our supply costs are generally collected from customers. In addition, Gross Margin is used by us to determine whether we are collecting the appropriate amount of energy costs from customers to allow for recovery of operating costs, as well as to analyze how changes in loads (due to weather, economic or other conditions), rates and other factors impact our results of operations. Our Gross Margin measure may not be comparable to that of other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Factors Affecting Results of Operations

Our revenues may fluctuate substantially with changes in supply costs, which are generally collected in rates from customers. In addition, various regulatory agencies approve the prices for electric and natural gas utility service within their respective jurisdictions and regulate our ability to recover costs from customers.

Revenues are also impacted by customer growth and usage, the latter of which is primarily affected by weather. Very cold winters increase demand for natural gas and to a lesser extent, electricity, while warmer than normal summers increase demand for electricity, especially among our residential and commercial customers. We measure this effect using degree-days, which is the difference between the average daily actual temperature and a baseline temperature of 65 degrees. Heating degree-days result when the average daily temperature is less than the baseline. Cooling degree-days result when the average daily temperature is greater than the baseline. The statistical weather information in our regulated segments represents a comparison of this data.

OVERALL CONSOLIDATED RESULTS

Three Months Ended September 30, 2019 Compared with the Three Months Ended September 30, 2018

	Electric		Natural Gas		Total	
	2019	2018	2019	2018	2019	2018
	(dollars in millions)					
Reconciliation of gross margin to operating revenue:						
Operating Revenues	$ 241.2	$ 245.2	$ 33.6	$ 34.7	$ 274.8	$ 279.9
Cost of Sales	58.7	66.5	5.5	5.7	64.2	72.2
Gross Margin(1)	**$ 182.5**	**$ 178.7**	**$ 28.1**	**$ 29.0**	**$ 210.6**	**$ 207.7**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

	Three Months Ended September 30,			
	2019	2018	Change	% Change
	(dollars in millions)			
Gross Margin				
Electric	$ 182.5	$ 178.7	$ 3.8	2.1 %
Natural Gas	28.1	29.0	(0.9)	(3.1)
Total Gross Margin(1)	**$ 210.6**	**$ 207.7**	**$ 2.9**	**1.4%**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

Primary components of the change in gross margin include the following (in millions):

	Gross Margin 2019 vs. 2018
Gross Margin Items Impacting Net Income	
Tax Cuts and Jobs Act impact	$ 2.8
Montana electric supply cost recovery	1.9
Montana electric rates, subject to refund	1.6
Natural gas retail volumes	0.3
Electric retail volumes	(1.9)
Electric transmission	(1.8)
Montana natural gas rates	(0.3)
Other	(2.3)
Change in Gross Margin Impacting Net Income	**0.3**
Gross Margin Items Offset Within Net Income	
Property taxes recovered in trackers	1.6
Production tax credits flowed-through trackers	1.4
Operating expenses recovered in trackers	(0.4)
Change in Items Offset Within Net Income	**2.6**
Increase in Consolidated Gross Margin(1)	**$ 2.9**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

Consolidated gross margin for items impacting net income increased $0.3 million due to the following items:

- A reduction in revenue in 2018 due to the impact of the Tax Cuts and Jobs Act one-time settlements offset in part by the associated ongoing decrease to natural gas retail rates;
- Lower Montana electric supply costs in 2019 as compared with 2018 due to market prices and an intermittent outage at Colstrip Unit 4 in the third quarter of 2018;
- An increase in Montana electric revenue recognized consistent with the proposed electric rate case settlement, effective with interim rates April 1, 2019 and subject to refund, as discussed above; and

- An increase in natural gas volumes due to customer growth and higher usage by our commercial customers offset in part by lower residential usage.

These increases were partly offset by the following items:

- A decrease in electric residential retail volumes due primarily to milder summer weather, offset in part by customer growth;
- Lower demand to transmit energy across our transmission lines due to market conditions and pricing; and
- A decrease in Montana natural gas rates associated with the annual step down for our Montana gas production assets.

The change in consolidated gross margin also includes the following items that had no impact on net income:

- An increase in revenues for property taxes included in trackers, offset by increased property tax expense;
- An increase in revenue due to the decrease in production tax credit benefits passed through to customers in our tracker mechanisms, which are offset by increased income tax expense; and
- A decrease in revenues for operating costs included in trackers, offset by a decrease in associated operating expense.

	Three Months Ended September 30,			
	2019	2018	Change	% Change
	(dollars in millions)			
Operating Expenses (excluding cost of sales)				
Operating, general and administrative	$ 77.0	$ 73.8	$ 3.2	4.3 %
Property and other taxes	44.1	42.5	1.6	3.8
Depreciation and depletion	43.2	43.6	(0.4)	(0.9)
	$ 164.3	**$ 159.9**	**$ 4.4**	**2.8%**

Consolidated operating, general and administrative expenses were $77.0 million for the three months ended September 30, 2019, as compared with $73.8 million for the three months ended September 30, 2018. Primary components of the change include the following (in millions):

	Operating, General & Administrative Expenses 2019 vs. 2018
Operating, General & Administrative Expenses Impacting Net Income	
Employee benefits	$ 2.7
Hazard trees	1.2
Labor	0.5
Legal costs	0.4
Generation maintenance	(1.0)
Other	2.4
Change in Items Impacting Net Income	**6.2**
Operating, General & Administrative Expenses Offset Within Net Income	
Pension and other postretirement benefits	(2.5)
Operating expenses recovered in trackers	(0.4)
Non-employee directors deferred compensation	(0.1)
Change in Items Offset Within Net Income	**(3.0)**
Increase in Operating, General & Administrative Expenses	**$ 3.2**

Consolidated operating, general and administrative expenses for items impacting net income increased $6.2 million due to the following items:

- Higher employee benefit costs due primarily to increased pension expense;
- Higher hazard tree line clearance costs;
- Increased labor costs due primarily to compensation increases; and
- Higher general legal costs.

These increases were offset by lower costs in 2019 for maintenance at our electric generation facilities.

The change in consolidated operating, general and administrative expenses also includes the following items that had no impact on net income:

- The regulatory treatment of the non-service cost components of pension and postretirement benefit expense, which is offset in other income;
- Lower operating expenses included in trackers recovered through revenue; and
- A change in value of non-employee directors deferred compensation due to changes in our stock price, offset in other income.

Property and other taxes were $44.1 million for the three months ended September 30, 2019, as compared with $42.5 million in the same period of 2018. This increase was primarily due to plant additions and higher estimated property valuations in Montana. We estimate property taxes throughout each year, and update based on valuation reports received from the Montana Department of Revenue. Under Montana law, we are allowed to track the increases in the actual level of state and local taxes and fees and adjust our rates to recover the increase between rate cases less the amount allocated to FERC-jurisdictional customers and net of the associated income tax benefit.

Depreciation and depletion expense was $43.2 million for the three months ended September 30, 2019, as compared with $43.6 million in the same period of 2018. This decrease was primarily due to the depreciation adjustment consistent with the proposed Montana electric rate case settlement, as discussed above, partly offset by plant additions.

Consolidated operating income for the three months ended September 30, 2019 was $46.4 million as compared with $47.8 million in the same period of 2018. This decrease was primarily due to higher operating expenses.

Consolidated interest expense for the three months ended September 30, 2019 was $23.7 million as compared with $22.0 million in the same period of 2018, due primarily to higher borrowings.

Consolidated other expense was $0.4 million for the three months ended September 30, 2019 as compared to other income of $2.1 million during the same period of 2018. This change includes a $0.1 million decrease in the value of deferred shares held in trust for non-employee directors deferred compensation and a $2.5 million increase in other pension expense, both of which are offset in operating, general, and administrative expense with no impact to net income. These decreases were partly offset by higher capitalization of Allowance for Funds Used During Construction (AFUDC).

Consolidated income tax expense for the three months ended September 30, 2019 was $0.6 million as compared with an income tax benefit of $0.4 million in the same period of 2018.

The following table summarizes the differences between our effective tax rate and the federal statutory rate (in millions):

	Three Months Ended September 30,					
	2019			2018		
Income Before Income Taxes	$	22.2		$	27.8	
Income tax calculated at federal statutory rate		4.7	21.0%		5.8	21.0 %
Permanent or flow-through adjustments:						
State income, net of federal provisions		0.1	0.3		0.6	2.3
Flow-through repairs deductions		(2.6)	(11.7)		(2.4)	(8.6)
Production tax credits		(1.4)	(6.3)		(1.6)	(6.0)
Amortization of excess deferred income tax		(0.4)	(1.7)		(0.4)	(1.5)
Plant and depreciation of flow-through items		(0.3)	(1.2)		(0.1)	(0.3)
Prior year permanent return to accrual adjustments		0.6	2.5		(3.0)	(10.7)
Other, net		(0.1)	(0.4)		0.7	2.5
		(4.1)	(18.5)		(6.2)	(22.3)
Income tax expense (benefit)	$	0.6	2.5%	$	(0.4)	(1.3)%

We compute income tax expense for each quarter based on the estimated annual effective tax rate for the year, adjusted for certain discrete items. Our effective tax rate typically differs from the federal statutory tax rate primarily due to the regulatory impact of flowing through federal and state tax benefits of repairs deductions, state tax benefit of accelerated tax depreciation deductions (including bonus depreciation when applicable) and production tax credits.

Consolidated net income for the three months ended September 30, 2019 was $21.7 million as compared with $28.2 million for the same period in 2018. This decrease was primarily due to higher operating costs.

Nine Months Ended September 30, 2019 Compared with the Nine Months Ended September 30, 2018

	Electric		Natural Gas		Total	
	2019	2018	2019	2018	2019	2018
	(dollars in millions)					
Reconciliation of gross margin to operating revenue:						
Operating Revenues	$ 733.9	$ 693.3	$ 195.9	$ 189.9	$ 929.8	$ 883.2
Cost of Sales	178.4	143.4	57.3	57.1	235.7	200.5
Gross Margin[(1)]	**$ 555.5**	**$ 549.9**	**$ 138.6**	**$ 132.8**	**$ 694.1**	**$ 682.7**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

	Nine Months Ended September 30,			
	2019	2018	Change	% Change
	(dollars in millions)			
Gross Margin				
Electric	$ 555.5	$ 549.9	$ 5.6	1.0 %
Natural Gas	138.6	132.8	5.8	4.4
Total Gross Margin[(1)]	**$ 694.1**	**$ 682.7**	**$ 11.4**	**1.7%**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

Primary components of the change in gross margin include the following (in millions):

	Gross Margin 2019 vs. 2018
Gross Margin Items Impacting Net Income	
Tax Cuts and Jobs Act impact	$ 15.4
Electric and natural gas retail volumes	12.1
Montana electric supply cost recovery	4.9
Montana electric rates, subject to refund	2.8
Electric QF liability adjustment	(20.9)
Electric transmission	(4.1)
Montana natural gas rates	(1.6)
Other	(2.1)
Change in Gross Margin Impacting Net Income	**6.5**
Gross Margin Items Offset Within Net Income	
Property taxes recovered in trackers	4.5
Production tax credits flowed-through trackers	1.7
Operating expenses recovered in trackers	(1.3)
Change in Items Offset Within Net Income	**4.9**
Increase in Consolidated Gross Margin[(1)]	**$ 11.4**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

Consolidated gross margin for items impacting net income increased $6.5 million due to the following items:

- A reduction in revenue in 2018 due to the impact of the Tax Cuts and Jobs Act one-time settlements, offset in part by the associated ongoing decrease to natural gas retail rates;
- An increase in electric and gas retail volumes due primarily to colder winter weather and customer growth;
- The recovery of Montana electric supply costs due to changes in the associated statute, as discussed above, and lower supply costs in 2019 as compared with 2018 due to market prices and an intermittent outage at Colstrip Unit 4 in the third quarter of 2018; and
- An increase in Montana electric revenue recognized consistent with the proposed electric rate case settlement, effective with interim rates April 1, 2019 and subject to refund, as discussed above.

These increases were partly offset by the following items:

- The adjustment of our electric QF liability (unrecoverable costs associated with PURPA contracts as a part of a 2002 stipulation with the MPSC and other parties) as compared with the same period in 2018 due to the combination of:
  - A lower periodic adjustment of approximately $14.2 million due to price escalation, which was less than previously estimated; and
  - A lower impact of the adjustment to actual output and pricing for the contract year resulting in approximately $6.7 million in higher supply costs for these QF contracts due primarily to outages at two facilities in 2018.
- Lower demand to transmit energy across our transmission lines due to market conditions and pricing; and
- A decrease in Montana natural gas rates associated with the annual step down for our Montana gas production assets.

The change in consolidated gross margin also includes the following items that had no impact on net income:

- An increase in revenues for property taxes included in trackers, offset by increased property tax expense;
- An increase in revenue due to the decrease in production tax credit benefits passed through to customers in our tracker mechanisms, which are offset by increased income tax expense; and
- A decrease in revenues for operating costs included in trackers, offset by a decrease in associated operating expense.

	Nine Months Ended September 30,			
	2019	2018	Change	% Change
	(dollars in millions)			
Operating Expenses (excluding cost of sales)				
Operating, general and administrative	$ 238.9	$ 222.0	$ 16.9	7.6 %
Property and other taxes	133.2	128.3	4.9	3.8
Depreciation and depletion	129.8	130.9	(1.1)	(0.8)
	$ 501.9	**$ 481.2**	**$ 20.7**	**4.3%**

Consolidated operating, general and administrative expenses were $238.9 million for the nine months ended September 30, 2019, as compared with $222.0 million for the nine months ended September 30, 2018. Primary components of the change include the following (in millions):

	Operating, General & Administrative Expenses 2019 vs. 2018
Operating, General & Administrative Expenses Impacting Net Income	
Employee benefits	$ 5.3
Hazard trees	3.9
Generation maintenance	2.4
Labor	1.6
Legal costs	1.4
Other	6.8
Change in Items Impacting Net Income	**21.4**
Operating, General & Administrative Expenses Offset Within Net Income	
Pension and other postretirement benefits	(6.2)
Operating expenses recovered in trackers	(1.3)
Non-employee directors deferred compensation	3.0
Change in Items Offset Within Net Income	**(4.5)**
Increase in Operating, General & Administrative Expenses	**$ 16.9**

Consolidated operating, general and administrative expenses for items impacting net income increased $21.4 million due to the following items:

- Higher employee benefit costs due primarily to increased pension expense, which we expect to be approximately $3 to $4 million higher in 2019 as compared with 2018 on an annual basis due primarily to higher funding of our Montana plan;
- Higher hazard tree line clearance costs, which we expect to continue in 2019 and beyond as previously disclosed;
- Higher costs in 2019 due to maintenance at electric generation facilities;
- Increased labor costs due primarily to compensation increases; and
- Higher general legal costs.

The change in consolidated operating, general and administrative expenses also includes the following items that had no impact on net income:

- The regulatory treatment of the non-service cost components of pension and postretirement benefit expense, which is offset in other income;
- Lower operating expenses included in trackers recovered through revenue; and
- A change in value of non-employee directors deferred compensation due to changes in our stock price, offset in other income.

Property and other taxes were $133.2 million for the nine months ended September 30, 2019, as compared with $128.3 million in the same period of 2018. This increase was primarily due to plant additions and higher estimated property valuations in Montana.

Depreciation and depletion expense was $129.8 million for the nine months ended September 30, 2019, as compared with $130.9 million in the same period of 2018. This decrease was primarily due to the depreciation adjustment consistent with the proposed Montana electric rate case settlement, as discussed above, partly offset by plant additions.

Consolidated operating income for the nine months ended September 30, 2019 was $192.2 million as compared with $201.5 million in the same period of 2018. This decrease was primarily due to higher operating expenses, partly offset by higher gross margin.

Consolidated interest expense for the nine months ended September 30, 2019 was $71.0 million as compared with $68.2 million in the same period of 2018, due primarily to higher borrowings.

Consolidated other income was $0.9 million for the nine months ended September 30, 2019 as compared to $1.8 million during the same period of 2018. This decrease was primarily due to a $6.2 million increase in other pension expense that was partly offset by a $3.0 million increase in the value of deferred shares held in trust for non-employee directors deferred compensation, both of which are offset in operating, general, and administrative expense with no impact to net income. This decrease was also partly offset by higher capitalization of AFUDC.

Consolidated income tax benefit for the nine months ended September 30, 2019 was $20.1 million as compared with income tax expense of $4.7 million in the same period of 2018. The income tax benefit for 2019 reflects the release of approximately $22.8 million of unrecognized tax benefits, including approximately $2.7 million of accrued interest and penalties, due to the lapse of statutes of limitation in the second quarter of 2019. Our effective tax rate for the nine months ended September 30, 2019 was negative 16.5% as compared with 3.4% for the same period of 2018. We expect our 2019 effective tax rate to range between negative 7% and negative 12%.

The following table summarizes the differences between our effective tax rate and the federal statutory rate (in millions):

	Nine Months Ended September 30,			
	2019		2018	
Income Before Income Taxes	$ 122.0		$ 135.1	
Income tax calculated at federal statutory rate	25.6	21.0 %	28.4	21.0%
Permanent or flow-through adjustments:				
State income, net of federal provisions	1.2	1.0	2.2	1.6
Release of unrecognized tax benefit	(22.8)	(18.7)	—	—
Flow-through repairs deductions	(12.7)	(10.4)	(13.1)	(9.7)
Production tax credits	(7.3)	(5.9)	(8.1)	(6.0)
Plant and depreciation of flow-through items	(2.5)	(2.0)	(1.6)	(1.2)
Amortization of excess deferred income tax	(1.9)	(1.6)	(2.0)	(1.5)
Prior year permanent return to accrual adjustments	0.6	0.4	(3.0)	(2.2)
Share-based compensation	0.2	0.2	0.3	0.2
Other, net	(0.5)	(0.5)	1.6	1.2
	(45.7)	(37.5)	(23.7)	(17.6)
Income tax (benefit) expense	$ (20.1)	(16.5)%	$ 4.7	3.4%

We compute income tax expense for each quarter based on the estimated annual effective tax rate for the year, adjusted for certain discrete items. Our effective tax rate typically differs from the federal statutory tax rate primarily due to the regulatory impact of flowing through federal and state tax benefits of repairs deductions, state tax benefit of accelerated tax depreciation deductions (including bonus depreciation when applicable) and production tax credits.

Consolidated net income for the nine months ended September 30, 2019 was $142.1 million as compared with $130.5 million for the same period in 2018. This increase was due primarily to the income tax benefit, colder winter weather and customer growth, and a reduction in revenue in 2018 due to impacts of the Tax Cuts and Jobs Act. These increases were partly offset by the adjustment of our electric QF liability and higher operating expenses.

ELECTRIC SEGMENT

We have various classifications of electric revenues, defined as follows:

- Retail: Sales of electricity to residential, commercial and industrial customers.
- Regulatory amortization: Primarily represents timing differences for electric supply costs and property taxes between when we incur these costs and when we recover these costs in rates from our customers.
- Transmission: Reflects transmission revenues regulated by the FERC.
- Wholesale and other are largely gross margin neutral as they are offset by changes in cost of sales.

Three Months Ended September 30, 2019 Compared with the Three Months Ended September 30, 2018

	Results			
	2019	2018	Change	% Change
	(dollars in millions)			
Retail revenues	$ 221.4	$ 215.5	$ 5.9	2.7 %
Regulatory amortization	4.6	16.8	(12.2)	(72.6)
Total retail revenues	226.0	232.3	(6.3)	(2.7)
Transmission	13.3	11.3	2.0	17.7
Wholesale and Other	1.9	1.6	0.3	18.8
Total Revenues	**241.2**	**245.2**	**(4.0)**	**(1.6)**
Total Cost of Sales	**58.7**	**66.5**	**(7.8)**	**(11.7)**
Gross Margin(1)	**$ 182.5**	**$ 178.7**	**$ 3.8**	**2.1%**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

	Revenues		Megawatt Hours (MWH)		Avg. Customer Counts	
	2019	2018	2019	2018	2019	2018
	(in thousands)					
Montana	$ 68,469	$ 67,567	569	582	303,263	299,612
South Dakota	15,987	16,483	141	145	50,596	50,541
Residential	**84,456**	**84,050**	**710**	**727**	**353,859**	**350,153**
Montana	87,754	85,774	807	816	69,217	67,724
South Dakota	26,295	24,403	291	280	12,873	12,808
Commercial	**114,049**	**110,177**	**1,098**	**1,096**	**82,090**	**80,532**
Industrial	10,523	9,833	766	654	78	75
Other	12,324	11,431	90	91	8,140	8,017
Total Retail Electric	**$ 221,352**	**$ 215,491**	**2,664**	**2,568**	**444,167**	**438,777**

	Cooling Degree Days			2019 as compared with:	
	2019	2018	Historic Average	2018	Historic Average
Montana	332	305	350	9% warmer	5% cooler
South Dakota	606	706	640	14% cooler	5% colder
	Heating Degree Days			**2019 as compared with:**	
	2019	2018	Historic Average	2018	Historic Average
Montana	319	383	276	17% warmer	16% cooler
South Dakota	37	23	84	61% cooler	56% warmer

The following summarizes the components of the changes in electric gross margin for the three months ended September 30, 2019 and 2018 (in millions):

	Gross Margin 2019 vs. 2018
Gross Margin Items Impacting Net Income	
Tax Cuts and Jobs Act impact	$ 1.8
Montana supply cost recovery	1.9
Montana rates, subject to refund	1.6
Retail volumes	(1.9)
Transmission	(1.8)
Other	(0.5)
Change in Gross Margin Impacting Net Income	1.1
Gross Margin Items Offset Within Net Income	
Production tax credits flowed-through trackers	1.4
Property taxes recovered in trackers	1.3
Change in Items Offset Within Net Income	2.7
Increase in Gross Margin(1)	**$ 3.8**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

Gross margin for items impacting net income increased $1.1 million primarily due to the following items:

- A reduction in revenue in 2018 due to the impact of the Tax Cuts and Jobs Act one-time settlements;
- Lower Montana electric supply costs in 2019 as compared with 2018 due primarily to higher market prices and lower generation from Colstrip Unit 4 due to an intermittent outage at Colstrip Unit 4 in the third quarter of 2018; and
- An increase in Montana electric revenue recognized consistent with the proposed electric rate case settlement, effective with interim rates April 1, 2019 and subject to refund, as discussed above.

These increases were partly offset by the following items:

- A decrease in residential retail volumes due primarily to milder weather, offset in part by customer growth; and
- Lower demand to transmit energy across our transmission lines due to market conditions and pricing.

The change in gross margin also includes the following items that had no impact on net income:

- An increase in revenues due to the decrease in production tax credit benefits passed through to customers in our tracker mechanisms, which are offset by increased income tax expense; and
- An increase in revenues for property taxes included in trackers, offset by increased property tax expense.

The change in regulatory amortization revenue is due to timing differences between when we incur electric supply costs and when we recover these costs in rates from our customers, which has a minimal impact on gross margin. Our wholesale and other revenues are largely gross margin neutral as they are offset by changes in cost of sales.

Nine Months Ended September 30, 2019 Compared with the Nine Months Ended September 30, 2018

	Results			
	2019	2018	Change	% Change
	(dollars in millions)			
Retail revenues	$ 658.9	$ 638.5	$ 20.4	3.2 %
Regulatory amortization	30.0	7.4	22.6	305.4
Total retail revenues	688.9	645.9	43.0	6.7
Transmission	40.2	42.8	(2.6)	(6.1)
Wholesale and Other	4.8	4.6	0.2	4.3
Total Revenues	**733.9**	**693.3**	**40.6**	**5.9**
Total Cost of Sales	**178.4**	**143.4**	**35.0**	**24.4**
Gross Margin[(1)]	**$ 555.5**	**$ 549.9**	**$ 5.6**	**1.0%**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

	Revenues		Megawatt Hours (MWH)		Avg. Customer Counts	
	2019	2018	2019	2018	2019	2018
	(in thousands)					
Montana	$ 225,392	$ 214,297	1,898	1,859	302,687	298,958
South Dakota	47,444	49,550	459	462	50,606	50,514
Residential	**272,836**	**263,847**	**2,357**	**2,321**	**353,293**	**349,472**
Montana	257,284	249,062	2,380	2,382	68,723	67,416
South Dakota	71,218	70,685	828	799	12,822	12,754
Commercial	**328,502**	**319,747**	**3,208**	**3,181**	**81,545**	**80,170**
Industrial	32,368	31,309	2,192	1,861	78	75
Other	25,228	23,568	150	149	6,336	6,259
Total Retail Electric	**$ 658,934**	**$ 638,471**	**7,907**	**7,512**	**441,252**	**435,976**

	Cooling Degree Days			2019 as compared with:	
	2019	2018	Historic Average	2018	Historic Average
Montana	370	337	402	10% warmer	8% colder
South Dakota	660	873	700	24% colder	6% colder
	Heating Degree Days			**2019 as compared with:**	
	2019	2018	Historic Average	2018	Historic Average
Montana	5,540	5,080	4,654	9% colder	19% colder
South Dakota	6,350	6,099	5,577	4% colder	14% colder

The following summarizes the components of the changes in electric gross margin for the nine months ended September 30, 2019 and 2018 (in millions):

	Gross Margin 2019 vs. 2018
Gross Margin Items Impacting Net Income	
Tax Cuts and Jobs Act impact	$ 13.3
Montana supply cost recovery	4.9
Retail volumes	3.1
Montana rates, subject to refund	2.8
QF liability adjustment	(20.9)
Transmission	(4.1)
Other	2.2
Change in Gross Margin Impacting Net Income	1.3
Gross Margin Items Offset Within Net Income	
Property taxes recovered in trackers	3.3
Production tax credits flowed-through trackers	1.7
Operating expenses recovered in trackers	(0.7)
Change in Items Offset Within Net Income	4.3
Increase in Gross Margin(1)	**$ 5.6**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

Gross margin for items impacting net income increased $1.3 million primarily due to the following items:

- A reduction in revenue in 2018 due to the impact of the Tax Cuts and Jobs Act one-time settlements;
- The recovery of Montana electric supply costs due to changes in the associated statute, as discussed above, partly offset by lower supply costs in 2019 as compared with 2018 due to market prices and an intermittent outage at Colstrip Unit 4 in the third quarter of 2018;
- An increase in retail volumes due primarily to colder winter weather and customer growth; and
- An increase in Montana electric revenue recognized consistent with the proposed electric rate case settlement, effective with interim rates April 1, 2019 and subject to refund, as discussed above.

These increases were partly offset by the following items:

- The adjustment of our electric QF liability (unrecoverable costs associated with PURPA contracts as a part of a 2002 stipulation with the MPSC and other parties) as compared with the same period in 2018 due to the combination of:
  - A lower periodic adjustment of approximately $14.2 million due to price escalation, which was less than previously estimated; and
  - A lower impact of the adjustment to actual output and pricing for the contract year resulting in approximately $6.7 million in higher supply costs for these QF contracts due to primarily to outages at two facilities in 2018.
- Lower demand to transmit energy across our transmission lines due to market conditions and pricing.

The change in gross margin also includes the following items that had no impact on net income:

- An increase in revenues for property taxes included in trackers, offset by increased property tax expense;
- An increase in revenues due to the decrease in production tax credit benefits passed through to customers in our tracker mechanisms, which are offset by increased income tax expense; and
- A decrease in revenues for operating costs included in trackers, offset by decreased operating expense.

The change in regulatory amortization revenue is due to timing differences between when we incur electric supply costs and when we recover these costs in rates from our customers, which has a minimal impact on gross margin. Our wholesale and other revenues are largely gross margin neutral as they are offset by changes in cost of sales.

NATURAL GAS SEGMENT

We have various classifications of natural gas revenues, defined as follows:

- Retail: Sales of natural gas to residential, commercial and industrial customers.
- Regulatory amortization: Primarily represents timing differences for natural gas supply costs and property taxes between when we incur these costs and when we recover these costs in rates from our customers, which is also reflected in cost of sales and therefore has minimal impact on gross margin.
- Wholesale: Primarily represents transportation and storage for others.

Three Months Ended September 30, 2019 Compared with the Three Months Ended September 30, 2018

	Results			
	2019	2018	Change	% Change
	(dollars in millions)			
Retail revenues	$ 20.3	$ 20.5	$ (0.2)	(1.0)%
Regulatory amortization	5.4	5.4	—	—
Total retail revenues	25.7	25.9	(0.2)	(0.8)
Wholesale and other	7.9	8.8	(0.9)	(10.2)
Total Revenues	**33.6**	**34.7**	**(1.1)**	**(3.2)**
Total Cost of Sales	**5.5**	**5.7**	**(0.2)**	**(3.5)**
Gross Margin[(1)]	**$ 28.1**	**$ 29.0**	**$ (0.9)**	**(3.1)%**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

	Revenues		Dekatherms (Dkt)		Customer Counts	
	2019	2018	2019	2018	2019	2018
	(in thousands)					
Montana	$ 8,909	$ 9,379	945	961	174,550	172,443
South Dakota	1,676	1,720	112	104	39,795	39,405
Nebraska	1,833	1,869	141	138	37,173	37,071
Residential	**12,418**	**12,968**	**1,198**	**1,203**	**251,518**	**248,919**
Montana	5,490	5,563	675	660	24,094	23,755
South Dakota	1,283	941	216	205	6,740	6,631
Nebraska	900	877	156	147	4,872	4,769
Commercial	**7,673**	**7,381**	**1,047**	**1,012**	**35,706**	**35,155**
Industrial	79	90	11	12	239	241
Other	97	60	14	7	166	162
Total Retail Gas	**$ 20,267**	**$ 20,499**	**2,270**	**2,234**	**287,629**	**284,477**

	Heating Degree Days			2019 as compared with:	
	2019	2018	Historic Average	2018	Historic Average
Montana	353	417	346	15% warmer	2% cooler
South Dakota	37	23	84	61% cooler	56% warmer
Nebraska	17	10	44	70% cooler	61% warmer

The following summarizes the components of the changes in natural gas gross margin for the three months ended September 30, 2019 and 2018:

	Gross Margin 2019 vs. 2018 (in millions)
Gross Margin Items Impacting Net Income	
Montana rates	$ (0.3)
Tax Cuts and Jobs Act impact	1.0
Retail volumes	0.3
Other	(1.8)
Change in Gross Margin Impacting Net Income	(0.8)
Gross Margin Items Offset Within Net Income	
Operating expenses recovered in trackers	(0.4)
Property taxes recovered in trackers	0.3
Change in Items Offset Within Net Income	(0.1)
Decrease in Gross Margin[1]	**$ (0.9)**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

Gross margin for items impacting net income decreased $0.8 million primarily due to the reduction of rates from the step down of our Montana gas production assets.

This decrease was partly offset by:

- A 2018 reduction in revenue due to the impact of the Tax Cuts and Jobs Act, offset in part by the associated ongoing decrease to natural gas retail rates; and
- An increase volumes due to customer growth and higher usage by our commercial customers offset in part by lower residential usage.

The change in gross margin also includes the following items that had no impact on net income:

- A decrease in revenues for operating costs included in trackers, offset by decreased operating expense; and
- An increase in revenues for property taxes included in trackers, offset by increased property tax expense.

Our wholesale and other revenues are largely gross margin neutral as they are offset by changes in cost of sales.

Nine Months Ended September 30, 2019 Compared with the Nine Months Ended September 30, 2018

	Results			
	2019	2018	Change	% Change
	(dollars in millions)			
Retail revenues	$ 171.1	$ 163.1	$ 8.0	4.9 %
Regulatory amortization	(1.7)	(2.8)	1.1	(39.3)
Total retail revenues	169.4	160.3	9.1	5.7
Wholesale and other	26.5	29.6	(3.1)	(10.5)
Total Revenues	**195.9**	**189.9**	**6.0**	**3.2**
Total Cost of Sales	**57.3**	**57.1**	**0.2**	**0.4**
Gross Margin(1)	**$ 138.6**	**$ 132.8**	**$ 5.8**	**4.4%**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

	Revenues		Dekatherms (Dkt)		Customer Counts	
	2019	2018	2019	2018	2019	2018
	(in thousands)					
Montana	$ 73,295	$ 67,856	10,025	8,960	174,555	172,477
South Dakota	20,376	18,745	2,545	2,480	40,019	39,628
Nebraska	15,678	18,273	2,181	2,145	37,373	37,306
Residential	**109,349**	**104,874**	**14,751**	**13,585**	**251,947**	**249,411**
Montana	37,987	34,874	5,458	4,853	24,171	23,839
South Dakota	14,074	12,397	2,481	2,372	6,789	6,673
Nebraska	8,294	9,406	1,612	1,555	4,894	4,816
Commercial	**60,355**	**56,677**	**9,551**	**8,780**	**35,854**	**35,328**
Industrial	672	810	101	118	240	245
Other	746	711	124	112	166	163
Total Retail Gas	**$ 171,122**	**$ 163,072**	**24,527**	**22,595**	**288,207**	**285,147**

	Heating Degree Days			2019 as compared with:	
	2019	2018	Historic Average	2018	Historic Average
Montana	5,604	5,094	4,838	10% colder	16% colder
South Dakota	6,350	6,099	5,577	4% colder	14% colder
Nebraska	4,866	4,938	4,585	1% warmer	6% colder

The following summarizes the components of the changes in natural gas gross margin for the nine months ended September 30, 2019 and 2018:

	Gross Margin 2019 vs. 2018 (in millions)
Gross Margin Items Impacting Net Income	
Retail volumes	$ 9.0
Tax Cuts and Jobs Act impact	2.1
Montana rates	(1.6)
Other	(4.3)
Change in Gross Margin Impacting Net Income	5.2
Gross Margin Items Offset Within Net Income	
Property taxes recovered in trackers	1.2
Operating expenses recovered in trackers	(0.6)
Change in Items Offset Within Net Income	0.6
Increase in Gross Margin(1)	**$ 5.8**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

Gross margin for items impacting net income increased $5.2 million primarily due to the following items:

- An increase in retail volumes from colder winter weather and customer growth; and
- A reduction in revenue in 2018 due to the impact of the Tax Cuts and Jobs Act one-time settlements, offset in part by the associated ongoing decrease to natural gas retail rates.

These increases were partly offset by a reduction of rates due to the step down of our Montana gas production assets.

The change in gross margin also includes the following items that had no impact on net income:

- An increase in revenues for property taxes included in trackers, offset by increased property tax expense; and
- A decrease in revenues for operating costs recovered in trackers, offset by decreased operating expense.

Our wholesale and other revenues are largely gross margin neutral as they are offset by changes in cost of sales.

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Funds

We require liquidity to support and grow our business, and use our liquidity for working capital needs, capital expenditures, investments in or acquisitions of assets, and to repay debt. We believe our cash flows from operations and existing borrowing capacity should be sufficient to fund our operations, service existing debt, pay dividends, and fund capital expenditures (excluding strategic growth opportunities). The amount of capital expenditures and dividends are subject to certain factors including the use of existing cash, cash equivalents and the receipt of cash from operations. In addition, a material change in operations or available financing could impact our current liquidity and ability to fund capital resource requirements, and we may defer a portion of our planned capital expenditures as necessary.

We issue debt securities to refinance retiring maturities, fund construction programs and for other general corporate purposes. To fund our strategic growth opportunities, we utilize available cash flow, debt capacity and equity issuances that allow us to maintain investment grade ratings.

We plan to maintain a 50 - 55 percent debt to total capital ratio excluding finance leases, and expect to continue to target a long-term dividend payout ratio of 60 - 70 percent of earnings per share; however, there can be no assurance that we will be able to meet these targets. In June 2019, we priced $150 million aggregate principal amount of Montana First Mortgage Bonds, at a fixed interest rate of 3.98% maturing in 2049. We issued $50 million of these bonds in June 2019 and the remaining $100 million of these bonds in September 2019 in transactions exempt from the registration requirements of the Securities Act of 1933, as amended. Proceeds were used to repay a portion of our outstanding borrowings under our revolving credit facilities and for other general corporate purposes. The bonds are secured by our electric and natural gas assets in Montana.

Liquidity is provided by internal cash flows and the use of our revolving credit facilities. We have a $400 million revolving credit facility. In addition, we have a $25 million revolving credit facility, to provide swingline borrowing capability. We utilize availability under our revolvers to manage our cash flows due to the seasonality of our business, and utilize any cash on hand in excess of current operating requirements to invest in our business and reduce borrowings.

As of September 30, 2019, our total net liquidity was approximately $198.0 million, including $5.0 million of cash and $193.0 million of revolving credit facility availability. As of September 30, 2019, there were no of letters of credit outstanding and $232.0 million in borrowings under our revolving credit facilities. Letters of credit were canceled effective April 29, 2019. Availability under our revolving credit facilities was $218.0 million as of October 25, 2019.

Factors Impacting our Liquidity

Supply Costs - Our operations are subject to seasonal fluctuations in cash flow. During the heating season, which is primarily from November through March, cash receipts from natural gas and electric sales typically exceed cash requirements. During the summer months, cash on hand, together with the seasonal increase in cash flows and utilization of our existing revolver, are used to purchase natural gas to place in storage, perform maintenance, and make capital improvements.

The effect of this seasonality on our liquidity is also impacted by changes in electric and natural gas market prices. We recover the cost of our electric and natural gas supply through tracking mechanisms. The natural gas supply tracking mechanism in each of our jurisdictions, and electric supply tracking mechanism in South Dakota are designed to provide stable recovery of supply costs, with a monthly adjustment to correct for any under or over collection. The Montana electric supply tracking mechanism implemented in 2018, the PCCAM, is designed for us to absorb risk through a sharing mechanism, with 90% of the variance above or below the established base revenues and actual costs collected from or refunded to customers. The change in design is discussed above in Management's Discussion and Analysis under Significant Trends and Regulation. Our electric supply rates were adjusted monthly under the prior tracker, and under the PCCAM design are adjusted annually. In periods of significant fluctuation of loads and / or market prices, this design impacts our cash flows as application of the PCCAM requires that we absorb certain power cost increases before we are allowed to recover increases from customers.

Due to the lag between our purchases of electric and natural gas commodities and revenue receipt from customers, cyclical over and under collection situations arise consistent with the fluctuations discussed above and we typically under collect in the fall and winter and over collect in the spring. Fluctuations in recoveries under our cost tracking mechanisms can have a significant effect on cash flows from operations and make year-to-year comparisons difficult.

As of September 30, 2019, we have under collected our costs recovered through tracking mechanisms by approximately $28.2 million. We over collected our costs by approximately $1.5 million as of December 31, 2018 and undercollected our costs by approximately $7.2 million as of September 30, 2018. As of December 31, 2017, we under collected our costs by approximately $13.2 million.

Credit Ratings

In general, less favorable credit ratings make debt financing more costly and more difficult to obtain on terms that are favorable to us and our customers, may impact our trade credit availability, and could result in the need to issue additional equity securities. Fitch Ratings (Fitch), Moody's Investors Service (Moody's), and S&P Global Ratings (S&P) are independent credit-rating agencies that rate our debt securities. These ratings indicate the agencies' assessment of our ability to pay interest and principal when due on our debt. As of October 25, 2019, our current ratings with these agencies are as follows:

	Senior Secured Rating	Senior Unsecured Rating	Commercial Paper	Outlook
Fitch	A	A-	F2	Negative
Moody's	A3	Baa2	Prime-2	Stable
S&P	A-	BBB	A-2	Stable

A security rating is not a recommendation to buy, sell or hold securities. Such rating may be subject to revision or withdrawal at any time by the credit rating agency and each rating should be evaluated independently of any other rating.

Cash Flows

The following table summarizes our consolidated cash flows (in millions):

	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
Operating Activities		
Net income	$ 142.1	$ 130.5
Non-cash adjustments to net income	117.4	142.8
Changes in working capital	2.4	92.1
Other noncurrent assets and liabilities	(8.0)	(19.0)
Cash Provided by Operating Activities	**253.9**	**346.4**
Investing Activities		
Property, plant and equipment additions	(242.9)	(193.4)
Acquisitions	—	(18.5)
Proceeds from sale of assets	—	0.1
Cash Used in Investing Activities	**(242.9)**	**(211.8)**
Financing Activities		
Proceeds from issuance of common stock, net	—	44.8
Issuance of long-term debt	150.0	—
Line of credit borrowings, net	(76.0)	222.0
Repayments of short-term borrowings, net	—	(319.6)
Dividends on common stock	(86.3)	(81.7)
Financing costs	(1.1)	(0.1)
Other	1.2	2.1
Cash Used in Financing Activities	**(12.2)**	**(132.5)**
(Decrease) Increase in Cash, Cash Equivalents, and Restricted Cash	**$ (1.2)**	**$ 2.1**
Cash, Cash Equivalents, and Restricted Cash, beginning of period	$ 15.3	$ 12.0
Cash, Cash Equivalents, and Restricted Cash, end of period	**$ 14.1**	**$ 14.1**

Cash Provided by Operating Activities

As of September 30, 2019, cash, cash equivalents, and restricted cash were $14.1 million as compared with $15.3 million at December 31, 2018 and $14.1 million at September 30, 2018. Cash provided by operating activities totaled $253.9 million for the nine months ended September 30, 2019 as compared with $346.4 million during the nine months ended September 30, 2018. This decrease in operating cash flows is primarily due to an under collection of supply costs from customers in 2019 as compared with an over collection in 2018, resulting in an approximate $44.9 million reduction in working capital, credits to Montana customers during the current period related to the Tax Cuts and Jobs Act of approximately $20.5 million, transmission generation interconnection refunds in the current period as compared with deposits in the prior period decreasing working capital by approximately $19.4 million, and the receipt of insurance proceeds of $6.1 million during the first quarter of 2018.

Cash Used in Investing Activities

Cash used in investing activities increased by approximately $31.1 million as compared with the first nine months of 2018. Plant additions during the first nine months of 2019 include maintenance additions of approximately $177.1 million and capacity related capital expenditures of $65.8 million. Plant additions during the first nine months of 2018 included maintenance additions of approximately $151.1 million, capacity related capital expenditures of approximately $42.3 million, and the purchase of the 9.7 MW Two Dot wind project in Montana for approximately $18.5 million.

Cash Used in Financing Activities

Cash used in financing activities totaled $12.2 million during the nine months ended September 30, 2019 as compared with $132.5 million during the nine months ended September 30, 2018. During the nine months ended September 30, 2019, cash used in financing activities reflects payment of dividends of $86.3 million and net repayments under our revolving lines of credit of $76.0 million, offset in part by proceeds from the issuance of debt of $150.0 million. During the nine months ended September 30, 2018, net cash used in financing activities reflects net repayments of commercial paper of $319.6 million and the payment of dividends of $81.7 million. These impacts were partially offset by issuances under our revolving lines of credit of $222.0 million.

Contractual Obligations and Other Commitments

We have a variety of contractual obligations and other commitments that require payment of cash at certain specified periods. The following table summarizes our contractual cash obligations and commitments as of September 30, 2019. See our Annual Report on Form 10-K for the year ended December 31, 2018 for additional discussion.

	Total	2019	2020	2021	2022	2023	Thereafter
				(in thousands)			
Long-term debt (1)	$ 2,188,637	$ —	$ —	$ 232,000	$ —	$ 144,660	$ 1,811,977
Finance leases	20,512	596	2,476	2,668	2,875	3,098	8,799
Estimated pension and other postretirement obligations (2)	54,900	6,568	12,199	12,214	12,046	11,873	N/A
Qualifying facilities liability (3)	649,516	18,723	76,533	78,356	80,226	82,320	313,358
Supply and capacity contracts (4)	1,717,939	57,427	150,866	117,099	118,880	114,100	1,159,567
Contractual interest payments on debt (5)	1,525,925	22,266	85,361	84,878	77,602	76,397	1,179,421
Environmental remediation obligations (6)	3,200	600	1,200	1,000	200	200	N/A
Total Commitments (7)	$ 6,160,629	$ 106,180	$ 328,635	$ 528,215	$ 291,829	$ 432,648	$ 4,473,122

(1) Represents cash payments for long-term debt and excludes $12.6 million of debt discounts and debt issuance costs, net.
(2) We estimate cash obligations related to our pension and other postretirement benefit programs for five years, as it is not practicable to estimate thereafter. Pension and postretirement benefit estimates reflect our expected cash contributions, which may be in excess of minimum funding requirements.
(3) Certain QFs require us to purchase minimum amounts of energy at prices ranging from $63 to $136 per MWH through 2029. Our estimated gross contractual obligation related to these QFs is approximately $649.5 million. A portion of the costs incurred to purchase this energy is recoverable through rates authorized by the MPSC, totaling approximately $523.0 million.
(4) We have entered into various purchase commitments, largely purchased power, electric transmission, coal and natural gas supply and natural gas transportation contracts. These commitments range from one to 25 years.
(5) Contractual interest payments includes our revolving credit facilities, which have a variable interest rate. We have assumed an average interest rate of 3.26% on the outstanding balance through maturity of the facilities.
(6) We estimate environmental remediation obligations for five years, as it is not practicable to estimate thereafter. Our environmental reserve relates primarily to the remediation of former manufactured gas plant sites owned by us.
(7) Potential tax payments related to uncertain tax positions are not practicable to estimate and have been excluded from this table.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Management's discussion and analysis of financial condition and results of operations is based on our Financial Statements, which have been prepared in accordance with GAAP. The preparation of these Financial Statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. We base our estimates on historical experience and other assumptions that are believed to be proper and reasonable under the circumstances.

We continually evaluate the appropriateness of our estimates and assumptions. Actual results could differ from those estimates. We consider an estimate to be critical if it is material to the Financial Statements and it requires assumptions to be made that were uncertain at the time the estimate was made and changes in the estimate are reasonably likely to occur from period to period. This includes the accounting for the following: regulatory assets and liabilities, pension and postretirement benefit plans, income taxes and qualifying facilities liability. These policies were disclosed in Management's Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report on Form 10-K for the year ended December 31, 2018. As of September 30, 2019, there have been no material changes in these policies.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risks, including, but not limited to, interest rates, energy commodity price volatility, and credit exposure. Management has established comprehensive risk management policies and procedures to manage these market risks.

Interest Rate Risk

Interest rate risks include exposure to adverse interest rate movements for outstanding variable rate debt and for future anticipated financings. We manage our interest rate risk by issuing primarily fixed-rate long-term debt with varying maturities, refinancing certain debt and, at times, hedging the interest rate on anticipated borrowings. All of our debt has fixed interest rates, with the exception of our revolving credit facilities. The $400 million revolving credit facility bears interest at the lower of prime plus a credit spread, ranging from 0.00% to 0.75%, or available rates tied to the Eurodollar rate plus a credit spread, ranging from 0.88% to 1.75%. In addition, we have a $25 million revolving credit facility, to provide swingline borrowing capability. The $25 million revolving credit facility bears interest at the lower of prime plus a credit spread of 0.13%, or available rates tied to the Eurodollar rate plus a credit spread of 0.65%. As of September 30, 2019, we had approximately $232.0 million in borrowings under our revolving credit facilities. A 1.0% increase in interest rates would increase our annual interest expense by approximately $2.3 million.

Commodity Price Risk

We are exposed to commodity price risk due to our reliance on market purchases to fulfill a portion of our electric and natural gas supply requirements. We also participate in the wholesale electric market to balance our supply of power from our own generating resources. Several factors influence price levels and volatility. These factors include, but are not limited to, seasonal changes in demand, weather conditions, available generating assets within regions, transportation availability and reliability within and between regions, fuel availability, market liquidity, and the nature and extent of current and potential federal and state regulations.

As part of our overall strategy for fulfilling our electric and natural gas supply requirements, we employ the use of market purchases and sales, including forward contracts. These types of contracts are included in our supply portfolios and in some instances, are used to manage price volatility risk by taking advantage of seasonal fluctuations in market prices. These contracts are part of an overall portfolio approach intended to provide price stability for consumers. As a regulated utility, our exposure to market risk caused by changes in commodity prices is mitigated because these commodity costs are included in our Montana, South Dakota and Nebraska cost tracking mechanisms and, are recoverable from customers subject to a regulatory review for prudency and, in the case of our Montana PCCAM, a sharing mechanism.

Counterparty Credit Risk

We are exposed to counterparty credit risk related to the ability of these counterparties to meet their contractual payment obligations, and the potential non-performance of counterparties to deliver contracted commodities or services at the contracted price. If counterparties seek financial protection under bankruptcy laws, we are exposed to greater financial risks. We are also exposed to counterparty credit risk related to providing transmission service to our customers under our Open Access Transmission Tariff and under gas transportation agreements. We have risk management policies in place to limit our transactions to high quality counterparties. We monitor closely the status of our counterparties and take action, as appropriate, to further manage this risk. This includes, but is not limited to, requiring letters of credit or prepayment terms. There can be no assurance, however, that the management tools we employ will eliminate the risk of loss.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We have established disclosure controls and procedures designed to ensure that information required to be disclosed in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms, and accumulated and reported to management, including the principal executive officer and principal financial officer to allow timely decisions regarding required disclosure.

We conducted an evaluation, under the supervision and with the participation of our principal executive officer and principal financial officer, of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934). Based on this evaluation, our principal executive officer and principal financial officer have concluded that, as of the end of the period covered by this report, our disclosure controls and procedures are effective.

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

See Note 10, Commitments and Contingencies, to the Financial Statements for information regarding legal proceedings.

ITEM 1A. RISK FACTORS

You should carefully consider the risk factors described below, as well as all other information available to you, before making an investment in our common stock or other securities.

We are subject to potential unfavorable state and federal regulatory outcomes. To the extent our incurred costs are deemed imprudent by the applicable regulatory commissions or certain regulatory mechanisms are not available, we may not recover some of our costs, which could adversely impact our results of operations and liquidity.

Our profitability is dependent on our ability to recover the costs of providing energy and utility services to our customers and earn a return on our capital investment in our utility operations. We provide service at rates established by several regulatory commissions. These rates are generally set based on an analysis of our costs incurred in a historical test year. In addition, each regulatory commission sets rates based in part upon their acceptance of an allocated share of total utility costs. When commissions adopt different methods to calculate inter-jurisdictional cost allocations, some costs may not be recovered. Thus, the rates we are allowed to charge may or may not match our costs at any given time. For instance, our Montana electric utility is regulated by the MPSC and the FERC. Differing schedules and regulatory practices between the MPSC and FERC expose us to the risk that we may not recover our costs due to timing of filings and issues such as cost allocation methodology.

While rate regulation is premised on providing a reasonable opportunity to earn a reasonable rate of return on invested capital, there can be no assurance that the applicable regulatory commission will judge all of our costs to have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of such costs. In addition to rate cases, our cost tracking mechanisms are a significant component of how we recover our costs.

Montana Regulation - We have received several unfavorable regulatory rulings in Montana, including:

- In 2018, the MPSC revised our recovery of prudently incurred supply costs to increase our risk by incorporating a sharing mechanism, which included a +/- $4.1 million deadband applied to the difference between actual costs and revenues, with differences beyond the deadband shared by allocating 90% to customers and 10% to shareholders. However, effective May 2019, the Montana legislature enacted legislation prohibiting a deadband.
- In 2018, the MPSC applied an alternative allocation methodology, reducing our recovery of Montana property taxes between general rate filings.
- In 2017, the MPSC revised our QF tariff for standard QF rates for small QFs (3 MW or less) to establish a maximum contract length of 15 years and a substantially lower rate for future QF contracts. The MPSC also applied the 15-year contract term to the economic evaluation of our future owned and contracted electric supply resources. As a result, we terminated our competitive solicitation process to address our intermittent capacity and reserve margin needs in Montana. We appealed the MPSC’s application of the 15-year term to our future owned and contracted electric supply resources, and in 2019, a Montana district court reversed the MPSC’s application of the 15-year term to our supply resources.
- In 2016, the MPSC disallowed replacement power costs from a 2013 outage at Colstrip Unit 4 requested in our electric tracker filings.
- In 2015, the MPSC issued an order eliminating the lost revenue adjustment mechanism, which allowed for recovery of fixed costs not recovered as a result of our energy efficiency program.
- In 2013, the MPSC concluded that costs associated with a 2012 outage at Dave Gates Generating Station were imprudently incurred, and disallowed recovery.

We submitted a general electric rate case filing with the MPSC in September 2018 and a hearing was held in May 2019. We cannot predict how the MPSC may address this filing. If the MPSC determines our request is not supported and / or decreases overall electric rates, it could have a material adverse effect on our operating and financial results.

FERC & Other Regulation - We must comply with established reliability standards and requirements including Critical Infrastructure Protection (CIP) Reliability Standards, which apply to North American Electric Reliability Corporation (NERC) functions. NERC reliability standards protect the nations' bulk power system against potential disruptions from cyber and physical security breaches. The FERC, NERC, or a regional reliability organization may assess penalties against any responsible entity that violates their rules, regulations or standards. Penalties for the most severe violations can reach as high as approximately $1.2 million per violation, per day. If a serious reliability incident or other incidence of noncompliance did occur, it could have a material adverse effect on our operating and financial results.

In May 2019, we submitted a filing with the FERC for our Montana transmission assets. The revenue collected from FERC-jurisdictional customers associated with our Montana FERC assets is reflected in our Montana MPSC-jurisdictional rates as a credit to retail customers. If the FERC determines our request is not supported and/or decreases overall electric rates, or the MPSC-jurisdictional electric rates are not updated consistent with the FERC decision, it could have a material adverse effect on our operating and financial results.

Early closure or unscheduled plant outages of our owned and jointly owned electric generating facilities due to operational or economic factors, environmental risks or litigation could have a material adverse impact on our results of operations and liquidity. We also rely on a limited number of suppliers of coal for our electric generation, making us vulnerable to increased prices for fuel as existing contracts expire or in the event of unanticipated interruptions in fuel supply.

Operation of electric generating facilities involves risks. Operational risks include facility shutdowns due to breakdown or failure of equipment or processes, interruptions in fuel supply, labor disputes, operator error, catastrophic events such as fires, explosions, floods, and intentional acts of destruction or other similar occurrences affecting the electric generating facilities; and operational changes necessitated by environmental legislation, litigation or regulation. The loss of a major electric generating facility would require us to find other sources of supply or ancillary services, if available, and expose us to higher purchased power costs, which may not be recovered from customers.

In addition, environmental advocacy groups and other third parties have in recent years undertaken greater efforts to oppose the continued operation of certain facilities, expressing concerns about the environmental and climate-related impacts from continued extraction, transportation, delivery and combustion of fossil fuels. These efforts may increase in scope and frequency depending on a number of variables, including the course of Federal and State environmental regulation and the financial resources devoted to these opposition activities. These risks include litigation originated by third parties against us due to greenhouse gas or other emissions or coal combustion residuals disposal and storage. We cannot predict the effect that any such opposition may have on our ability to operate and recover the costs of our generating facilities.

Early closure of our generation facilities due to economic conditions, environmental regulations and / or litigation could result in regulatory impairments or increased cost of operations. We are obligated to pay for the costs of closure of our share of generation facilities, including our share of the costs of reclamation of the mines that supply coal to the coal-fired power plants. Likewise, other owners or participants are responsible for their shares of the decommissioning and reclamation obligations. If recovery of our remaining investment in such facilities and the costs associated with early closure, including decommissioning, remediation, reclamation, and restoration are not recovered from customers, it could have a material adverse impact on our results of operations.

Colstrip - As part of the settlement of litigation brought by the Sierra Club and the Montana Environmental Information Center against the owners and operator of Colstrip, the owners of Units 1 and 2 agreed to shut down those units no later than July 2022. In June 2019, the owners of Units 1 and 2 accelerated the closure of those units to around December 31, 2019. We do not have ownership in Units 1 and 2, and decisions regarding these units, including their shut down, were made by their respective owners. The six owners of Colstrip currently share the operating costs pursuant to the terms of an operating agreement among the owners of Units 3 and 4 and a common facilities agreement among the owners of all four units. When Units 1 and 2 discontinue operation, we anticipate incurring some additional operating costs with respect to our interest in Unit 4 and expect to experience a negative impact on our transmission revenue due to reduced amounts of energy transmitted across our transmission lines. This reduction would be incorporated in our next general electric rate filing after the closure of Units 1 and 2, resulting in lower revenue credits to certain customers.

In addition, the remaining depreciable life of our investment in Colstrip Unit 4 is through 2042. Two of the other joint owners have entered into settlements with regulators and a third has filed a petition with its regulators to accelerate the recovery of their investment in Colstrip Units 3 and 4 by using a depreciable life through 2027. In May 2019, the Washington state legislature enacted a statute mandating Washington electric utilities to “eliminate coal-fired resources from [their] allocation of electricity” on or before December 31, 2025. The same three owners, which had earlier set and requested a depreciable life through 2027, are subject to this Washington statute and its 2025 deadline. One of those owners announced in October 2019 its intent to retire its shares of Units 3 and 4 in 2027. Recovery of costs associated with the shut-down of the facility prior to the end of the useful life would be subject to MPSC approval.

In addition, we have joint ownership in and operate the associated 500 kV transmission system. The closure of generation at Colstrip may impact the operation of this 500 kV system, and the joint owners may have differing needs with regard to ongoing operation of this system. This transmission system is an integral, essential part of our overall transmission system in Montana in order to maintain reliability, regardless of the status of the generation facilities.

Coal Supply - Colstrip Units 3 and 4 are supplied with fuel from adjacent coal reserves under coal supply and transportation agreements, which are effective through December 31, 2019. Our coal supply and transportation agreements are with WeCo, a subsidiary of Westmoreland Coal Co. (Westmoreland). Westmoreland, along with WeCo filed for Chapter 11 bankruptcy protection on October 9, 2018. After receiving no qualified bids at a January 2019 auction, a lenders group acquired Westmoreland's core assets, which included the mine adjacent to Colstrip, in March 2019. Immediately prior to that acquisition, WeCo assumed the existing coal supply and transportation agreements, which were assigned to the lenders group, which is now known as Westmoreland Rosebud Mining, LLC (WRM). We are working with WRM and the other joint owners of Colstrip to negotiate a new coal supply agreement, which may have higher costs than the existing coal supply agreement.

We are a captive rail shipper of the Burlington Northern Santa Fe Railway for shipments of coal to the Big Stone Plant (our largest source of generation in South Dakota), making us vulnerable to railroad capacity and operational issues and/or increased prices for coal transportation from a sole supplier.

Our electric and natural gas transmission and distribution operations involve numerous activities that may result in accidents, fires, system outages and other operating risks and costs that are unique to our industry.

Inherent in our electric and natural gas operations are a variety of hazards and operating risks, such as fires, electric contacts, leaks, explosions, catastrophic failures and mechanical problems. These risks could cause a loss of human life, significant damage to property, loss of customer load, environmental pollution, impairment of our operations, and substantial financial losses to us and others. For our natural gas lines located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the level of potential damages resulting from these risks could be significant.

For our electric distribution and transmission system, hazard trees located inside or outside our lines' rights of way pose risks. Hazard trees are those trees that are structurally unsound and could fall into our lines if the trees failed. We are facing challenges to address these trees. The risk of fires is exacerbated in forested areas where beetle infestations have caused a significant increase in the quantity of standing dead and dying timber, increasing the risk that such trees may fall from either inside or outside our right-of-way into a powerline igniting a fire. Fires alleged to have been caused by our system could expose us to significant damage claims on theories such as strict liability, negligence, gross negligence, trespass, inverse condemnation, and others.

We maintain insurance against some, but not all, of these risks and losses. The occurrence of any of these events not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

Cyber and physical attacks, threats of terrorism and catastrophic events that could result from terrorism, or individuals and/or groups attempting to disrupt our business, or the businesses of third parties, may affect our operations in unpredictable ways and could adversely affect our liquidity and results of operations. Failure to maintain the security of personally identifiable information could adversely affect us.

Business Operations - We are subject to the potentially adverse operating and financial effects of terrorist acts and threats, as well as cyber (such as hacking and viruses), physical security breaches and other disruptive activities of individuals or groups, and theft of our critical infrastructure information. Our generation, transmission and distribution facilities are deemed critical infrastructure and provide the framework for our service infrastructure. Cyber crime, which includes the use of malware, computer viruses, and other means for disruption or unauthorized access has increased in frequency, scope, and potential impact in recent years. Our assets and the information technology systems on which they depend could be direct targets of, or indirectly affected by, cyber attacks and other disruptive activities, including those that impact third party facilities that are interconnected to us. Any significant interruption of these assets or systems could prevent us from fulfilling our critical business functions including delivering energy to our customers, and sensitive, confidential and other data could be compromised.

Security threats continue to evolve and adapt. We and our third-party vendors have been subject to, and will likely continue to be subject to, attempts to gain unauthorized access to systems, or confidential data, or to disrupt operations. None of these attempts has individually or in aggregate resulted in a security incident with a material impact on our financial condition or results of operations. Despite implementation of security and control measures, there can be no assurance that we will be able to prevent the unauthorized access of our systems and data, or the disruption of our operations, either of which could have a material impact.

These events, and governmental actions in response, could result in a material decrease in revenues and significant additional costs to repair and insure assets, and could adversely affect our operations by contributing to the disruption of supplies and markets for electricity, natural gas, oil and other fuels. These events could also impair our ability to raise capital by contributing to financial instability and reduced economic activity.

Personally Identifiable Information - Our information systems and those of our third-party vendors contain confidential information, including information about customers and employees. Customers, shareholders, and employees expect that we will adequately protect their personal information. The regulatory environment surrounding information security and privacy is increasingly demanding. A data breach involving theft, improper disclosure, or other unauthorized access to or acquisition of confidential information could subject us to penalties for violation of applicable privacy laws, claims by third parties, and enforcement actions by government agencies. It could also reduce the value of proprietary information, and harm our reputation.

Federally mandated purchases of power from QFs, and integration of power generated from those projects in our system, may increase costs to our customers and decrease system reliability, limit our ability to make generation investments and adversely affect our business.

We are generally obligated under federal law to purchase power from certain QF projects, regardless of current load demand, availability of lower cost generation resources, transmission availability or market prices. These resources are primarily intermittent, non-dispatchable generation whose prices may be in excess of market prices during times of lower customer demand, and may not be able to generate electricity during peak times. These resources typically do not meet the requirements set forth in our supply plans for resource procurement. These requirements to purchase supply inconsistent with customer need may have several impacts, including increasing the likelihood and frequency that we will be required to reduce output from owned generation resources and that we will need to upgrade or build additional transmission facilities to serve QF projects. Either of these results would increase costs to customers. Further, balancing load and power generation on our system is challenging, and we expect that operational costs will increase as a result of integration of these intermittent, non-dispatchable generation projects. If we are unable to timely recover those costs through our power cost adjustment mechanism or otherwise, those increased costs may negatively affect our liquidity, results of operations and financial condition.

In addition, requirements to procure power from these sources could impact our ability to make generation investments depending upon the number and size of QF contracts we ultimately enter into. The cost to procure power from these QFs may not be a cost effective resource for customers, or the type of generation resource needed, resulting in increased supply costs that are inconsistent with resource plans developed based on a lowest cost and least risk basis while placing upward pressure on overall customer bills. This may impact our investment plans and financial condition.

Our electric and natural gas portfolios rely significantly on market purchases. Prices for electric power and natural gas are often unpredictable as they are subject to market volatility and general market disruption. This exposure adversely affects our ability to manage our operational requirements and costs, which ultimately could adversely affect our results of operations and liquidity.

We are obligated to supply power to retail customers and certain wholesale customers and procure natural gas to supply fuel for our natural gas fired generation. Our need to acquire flexible energy supply and capacity in the market to meet our electric and natural gas load serving obligations exposes us to certain risks. In Montana, approximately 46% of our peak electric requirements are served through market purchases. We experienced a new, all-time system peak on the Montana electric system in February 2019, further exacerbating our electric generation capacity and gas transmission deficiency. In addition, a significant number of base-load generation facilities, which may also serve to meet peak requirements, in the region are being retired or are scheduled to be retired in the next five to ten years. A decrease in the region’s electric capacity may impair the reliability of the grid, particularly during peak demand periods. In addition, our natural gas system serves both retail customers and the needs of natural gas fired electric generation. The natural gas system has capacity constraints that expose us to risks to be able to deliver natural gas during periods of peak demand.

There can be no assurance that there will be available counterparties to contract with to serve our customers' needs, or that these counterparties will fulfill their obligations to us. The suppliers under these agreements may experience financial or operational problems that inhibit their ability to fulfill their obligations to us.

Commodity pricing is an inherent risk component of our business operations and our financial results. Even though rate regulation is premised on full recovery of prudently incurred costs and a reasonable rate of return on invested capital, there can be no assurance that our costs are recoverable as discussed above. The prevailing market prices for electricity may fluctuate substantially over relatively short periods of time, potentially adversely impacting our results of operations, financial condition and cash flows due to our need for market purchases and our Montana electric supply recovery mechanism.

Fluctuations in actual weather conditions, generation availability, transmission constraints, and generation reserve margins may all have an impact on market prices for energy and capacity and the electricity consumption of our customers on a given day. Extreme weather conditions may force us to purchase electricity in the short-term market on days when weather is unexpectedly severe, and the pricing for market energy may be significantly higher on such days than the cost of electricity in our existing generation and contracts. Unusually mild weather conditions could leave us with excess power which may be sold in the market at a loss if the market price is lower than the cost of electricity in our existing contracts.

We are subject to extensive and changing environmental laws and regulations and potential environmental liabilities, which could have a material adverse effect on our liquidity and results of operations.

We are subject to extensive laws and regulations imposed by federal, state, and local government authorities in the ordinary course of operations with regard to the environment, including environmental laws and regulations relating to air and water quality, protection of natural resources, migratory birds and other wildlife, solid waste disposal, coal ash and other environmental considerations. We are also subject to judicial interpretations of those laws and regulations. We believe that we are in compliance with environmental regulatory requirements; however, possible future developments, such as more stringent environmental laws and regulations, the timing of future enforcement proceedings that may be taken by environmental authorities, and judicial opinions regarding those laws and regulations, could affect our costs and the manner in which we conduct our business and could require us to make substantial additional capital expenditures or abandon certain projects.

On June 19, 2019, EPA finalized the ACE. ACE repeals the 2015 CPP in regulating GHG emissions from coal-fired plants. Under the ACE, states must establish unit-specific standards that reflect emissions achievable through heat rate improvements, which EPA designated as the best system of emissions reduction, and if the state chooses, take into account the remaining useful life of the unit and other source specific factors. States generally have three years to submit the standards to EPA and coal-fired plants will have two additional years to comply with the standards. We cannot predict the impact of the ACE on us until the state plans are adopted and any judicial reviews are completed.

As GHG regulations are implemented, it could result in additional compliance costs that could affect our future results of operations and financial position if such costs are not recovered through regulated rates. Complying with the CO_2 emission performance standards, and with other future environmental rules, may make it economically impractical to continue operating all or a portion of our jointly owned facilities or for individual owners to participate in their proportionate ownership of the coal-fired generating units. This could lead to significant impacts to customer rates for recovery of plant improvements and / or closure related costs and costs to procure replacement power. In addition, these changes could impact system reliability due to changes in generation sources.

Many of these environmental laws and regulations provide for substantial civil and criminal fines for noncompliance which, if imposed, could result in material costs or liabilities. In addition, there is a risk of environmental damages claims from private parties or government entities. We may be required to make significant expenditures in connection with the investigation and remediation of alleged or actual spills, personal injury or property damage claims, and the repair, upgrade or expansion of our facilities to meet future requirements and obligations under environmental laws.

To the extent that costs exceed our estimated environmental liabilities, or we are not successful in recovering remediation costs or costs to comply with the proposed or any future changes in rules or regulations, our results of operations and financial position could be adversely affected.

We are subject to changing federal and state laws and regulations. Congress and state legislatures may enact legislation that adversely affects our operations and financial results.

We are subject to regulations under a wide variety of U.S. federal and state regulations and policies. Regulation affects almost every aspect of our business. Changes to federal and state laws and regulations are continuous and ongoing. Similarly, Congress may implement new federal laws that could adversely and materially affect us. There can be no assurance that laws, regulations and policies will not be changed in ways that result in significant impacts to our business. We cannot predict future changes in laws and regulations, how they will be implemented and interpreted, or the ultimate effect that this changing environment will have on us. Any changes may have a material adverse effect on our financial condition, results of operations, and cash flows.

Weather and weather patterns, including normal seasonal and quarterly fluctuations of weather, as well as extreme weather events that might be associated with climate change, could adversely affect our results of operations and liquidity.

Our electric and natural gas utility business is seasonal, and weather patterns can have a material impact on our financial performance. Demand for electricity and natural gas is often greater in the summer and winter months associated with cooling and heating. Because natural gas is heavily used for residential and commercial heating, the demand for this product depends heavily upon weather patterns throughout our market areas, and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our operations have historically generated less revenue and income when weather conditions are milder in the winter and cooler in the summer. Unusually mild winters or cool summers could adversely affect our results of operations and financial position. In addition, exceptionally hot summer weather or unusually cold winter weather could add significantly to working capital needs to fund higher than normal supply purchases to meet customer demand for electricity and natural gas. Our sensitivity to weather volatility is significant due to the absence of regulatory mechanisms, such as those authorizing revenue decoupling, lost margin recovery, and other innovative rate designs.

Severe weather impacts, including but not limited to, blizzards, thunderstorms, high winds, microbursts, fires, tornadoes and snow or ice storms can disrupt energy generation, transmission and distribution. We derive a significant portion of our energy supply from hydroelectric facilities, and the availability of water can significantly affect operations. Higher temperatures may decrease the Montana snowpack and impact the timing of run-off and may require us to purchase replacement power. Dry conditions also increase the threat of fires, which could threaten our communities and electric distribution and transmission lines and facilities. In addition, fires alleged to have been caused by our system could expose us to substantial property damage and other claims. Any damage caused as a result of fires could negatively impact our financial condition, results of operations or cash flows.

There is also a concern that the physical risks of climate change could include changes in weather conditions, such as changes in the amount or type of precipitation and extreme weather events. Climate change and the costs that may be associated with its impacts have the potential to affect our business in many ways, including increasing the cost incurred in providing electricity and natural gas, impacting the demand for and consumption of electricity and natural gas (due to change in both costs and weather patterns), and affecting the economic health of the regions in which we operate. Extreme weather conditions creating high energy demand on our own and/or other systems may raise market prices as we buy short-term energy to serve our own system. To the extent the frequency of extreme weather events increase, this could increase our cost of providing service. In addition, we may not recover all costs related to mitigating these physical and financial risks.

We must meet certain credit quality standards. If we are unable to maintain investment grade credit ratings, our liquidity, access to capital and operations could be materially adversely affected.

A downgrade of our credit ratings to less than investment grade could adversely affect our liquidity. Certain of our credit agreements and other credit arrangements with counterparties require us to provide collateral in the form of letters of credit or cash to support our obligations if we fall below investment grade. Also, a downgrade below investment grade could hinder our ability to raise capital on favorable terms and would increase our borrowing costs. Higher interest rates on borrowings with variable interest rates could also have an adverse effect on our results of operations.

Our revenues, results of operations and financial condition are impacted by customer growth and usage in our service territories and may fluctuate with current economic conditions or response to price increases. We are also impacted by market conditions outside of our service territories related to demand for transmission capacity and wholesale electric pricing.

Our revenues, results of operations and financial condition are impacted by customer growth and usage, which can be impacted by a number of factors, including the voluntary reduction of consumption of electricity and natural gas by our customers in response to increases in prices and demand-side management programs, economic conditions impacting decreases in their disposable income, and the use of distributed generation resources or other emerging technologies for electricity. Advances in distributed generation technologies that produce power, including fuel cells, micro-turbines, wind turbines and solar cells, may reduce the cost of alternative methods of producing power to a level competitive with central power station electric production. Customer-owned generation itself reduces the amount of electricity purchased from utilities and may have the effect of inappropriately increasing rates generally and increasing rates for customers who do not own generation, unless retail rates are designed to collect distribution grid costs across all customers in a manner that reflects the benefit from their use. Such developments could affect the price of energy, could affect energy deliveries as customer-owned generation becomes more cost-effective, could require further improvements to our distribution systems to address changing load demands and could make portions of our electric system power supply and transmission and/or distribution facilities obsolete prior to the end of their useful lives. Such technologies could also result in further declines in commodity prices or demand for delivered energy.

Decreasing use per customer (driven, for example, by appliance and lighting efficiency) and the availability of cost-effective distributed generation, put downward pressure on load growth. Our resource plan includes an expected load growth assumption of 0.8 percent annually, which reflects low customer and usage increases, offset in part by these load reduction measures. Reductions in usage, attributable to various factors could materially affect our results of operations, financial position, and cash flows through, among other things, reduced operating revenues, increased operating and maintenance expenses, and increased capital expenditures, as well as potential asset impairment charges or accelerated depreciation and decommissioning expenses over shortened remaining asset useful lives.

Demand for our Montana transmission capacity fluctuates with regional demand, fuel prices and weather related conditions. The levels of wholesale sales depend on the wholesale market price, market participants, transmission availability, the availability of generation, and the development of the Western Energy Imbalance Market and our expected participation, among other factors. Declines in wholesale market price, availability of generation, transmission constraints in the wholesale markets, or low wholesale demand could reduce wholesale sales. These events could adversely affect our results of operations, financial position and cash flows.

Our plans for future expansion through the acquisition of assets including natural gas reserves, capital improvements to existing assets, generation investments, and transmission grid expansion involve substantial risks.

Acquisitions include a number of risks, including but not limited to, regulatory approval, regulatory conditions, additional costs, the assumption of material liabilities, the diversion of management’s attention from daily operations to the integration of the acquisition, difficulties in assimilation and retention of employees, and securing adequate capital to support the transaction. The regulatory process in which rates are determined may not result in rates that produce full recovery of our investments, or a reasonable rate of return. Uncertainties also exist in assessing the value, risks, profitability, and liabilities associated with certain businesses or assets and there is a possibility that anticipated operating and financial synergies expected to result from an acquisition do not develop. The failure to successfully integrate future acquisitions that we may choose to undertake could have an adverse effect on our financial condition and results of operations.

Our business strategy also includes significant investment in capital improvements and additions to modernize existing infrastructure, generation investments and transmission capacity expansion. The completion of generation and natural gas investments and transmission projects are subject to many construction and development risks, including, but not limited to, risks related to permitting, financing, regulatory recovery, escalating costs of materials and labor, meeting construction budgets and schedules, and environmental compliance. In addition, these capital projects may require a significant amount of capital expenditures. We cannot provide certainty that adequate external financing will be available to support such projects. Additionally, borrowings incurred to finance construction may adversely impact our leverage, which could increase our cost of capital.

Poor investment performance of plan assets of our defined benefit pension and postretirement benefit plans, in addition to other factors impacting these costs, could unfavorably impact our results of operations and liquidity.

Our costs for providing defined benefit retirement and postretirement benefit plans are dependent upon a number of factors. Assumptions related to future costs, return on investments and interest rates have a significant impact on our funding requirements related to these plans. These estimates and assumptions may change based on economic conditions, actual stock market performance and changes in governmental regulations. Without sustained growth in the plan assets over time and depending upon interest rate changes as well as other factors noted above, the costs of such plans reflected in our results of operations and financial position and cash funding obligations may change significantly from projections.

Our obligation to include a minimum annual quantity of power in our Montana electric supply portfolio at an agreed upon price per MWH could expose us to material commodity price risk if certain QFs under contract with us do not perform during a time of high commodity prices, as we are required to make up the difference. In addition, we are subject to price escalation risk with one of the largest QF contracts.

As part of a stipulation in 2002 with the MPSC and other parties, we agreed to include a minimum annual quantity of power in our Montana electric supply portfolio at an agreed upon price per MWH through June 2029. This obligation is reflected in the electric QF liability, which reflects the unrecoverable costs associated with these specific QF contracts per the stipulation. The annual minimum energy requirement is achievable under normal operations of these facilities, including normal periods of planned and forced outages. However, to the extent the supplied power for any year does not reach the minimum quantity set forth in the settlement, we are obligated to purchase the difference from other sources. The anticipated source for any shortfall is the wholesale market, which would subject us to commodity price risk if the cost of replacement power is higher than contracted rates.

In addition, we are subject to price escalation risk with one of the largest contracts included in the electric QF liability due to variable contract terms. In recording the electric QF liability, we estimated an annual escalation rate of three percent over the remaining term of the contract (through June 2024). To the extent the annual escalation rate exceeds three percent, our results of operations, cash flows and financial position could be adversely affected.

ITEM 6. EXHIBITS -

(a) Exhibits

Exhibit 4.1—Thirty-Ninth Supplemental Indenture, dated as of September 1, 2019, among NorthWestern Corporation and The Bank of New York Mellon and Beata Harvin, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated September 20, 2019, Commission File No. 1-10499).

Exhibit 31.1—Certification of chief executive officer pursuant to Section 302 of the Sarbanes Oxley Act of 2002.

Exhibit 31.2—Certification of chief financial officer pursuant to Section 302 of the Sarbanes Oxley Act of 2002.

Exhibit 32.1—Certification of chief executive officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Exhibit 32.2—Certification of chief financial officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Exhibit 101.INS—XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.

Exhibit 101.SCH—XBRL Taxonomy Extension Schema Document

Exhibit 101.CAL—XBRL Taxonomy Extension Calculation Linkbase Document

Exhibit 101.DEF—XBRL Taxonomy Extension Definition Linkbase Document

Exhibit 101.LAB—XBRL Taxonomy Label Linkbase Document

Exhibit 101.PRE—XBRL Taxonomy Extension Presentation Linkbase Document

104 Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

SIGNATURES

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 thereunto duly authorized.

		NorthWestern Corporation
Date: October 30, 2019	By:	/s/ BRIAN B. BIRD
		Brian B. Bird
		Chief Financial Officer
		Duly Authorized Officer and Principal Financial Officer