

**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 March 31, 2020

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 CORP

(Exact name of registrant as specified in its charter)

Delaware

(State or other jurisdiction of
incorporation or organization)

46-0172280

(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, 50,568,881 shares outstanding at April 17, 2020

NORTHWESTERN CORPORATION

FORM 10-Q

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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;
- the impact of extraordinary external events, such as the recent outbreak of the novel coronavirus (COVID-19) pandemic 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.

PART 1. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS (UNAUDITED)

NORTHWESTERN CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(Unaudited)

(in thousands, except per share amounts)

	Three Months Ended March 31,	
	2020	2019
Revenues		
Electric	\$ 244,625	\$ 273,037
Gas	90,630	111,183
Total Revenues	335,255	384,220
Operating Expenses		
Cost of sales	91,272	115,735
Operating, general and administrative	79,005	81,092
Property and other taxes	44,499	44,789
Depreciation and depletion	45,265	45,584
Total Operating Expenses	260,041	287,200
Operating Income	75,214	97,020
Interest Expense, net	(24,334)	(23,790)
Other (Expense) Income, net	(1,982)	1,149
Income Before Income Taxes	48,898	74,379
Income Tax Benefit (Expense)	1,806	(1,573)
Net Income	\$ 50,704	\$ 72,806
Average Common Shares Outstanding	50,507	50,381
Basic Earnings per Average Common Share	\$ 1.00	\$ 1.45
Diluted Earnings per Average Common Share	\$ 1.00	\$ 1.44
Dividends Declared per Common Share	\$ 0.60	\$ 0.575

See Notes to Condensed Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)

(in thousands)

	Three Months Ended March 31,	
	2020	2019
Net Income	\$ 50,704	\$ 72,806
Other comprehensive income, net of tax:		
Foreign currency translation	101	63
Reclassification of net losses on derivative instruments	113	112
Total Other Comprehensive Income	214	175
Comprehensive Income	\$ 50,918	\$ 72,981

See Notes to Condensed Consolidated Financial Statements

NORTHWESTERN CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

(in thousands, except share data)

	<u>March 31, 2020</u>	<u>December 31, 2019</u>
ASSETS		
Current Assets:		
Cash and cash equivalents	\$ 56,393	\$ 5,145
Restricted cash	8,750	6,925
Accounts receivable, net	155,911	167,405
Inventories	53,236	53,925
Regulatory assets	44,587	54,432
Other	11,425	13,895
Total current assets	330,302	301,727
Property, plant, and equipment, net	4,717,515	4,700,924
Goodwill	357,586	357,586
Regulatory assets	496,935	484,131
Other noncurrent assets	64,605	66,334
Total Assets	\$ 5,966,943	\$ 5,910,702
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current maturities of finance leases	\$ 2,522	\$ 2,476
Accounts payable	66,507	96,690
Accrued expenses	237,947	202,021
Regulatory liabilities	41,339	33,080
Total current liabilities	348,315	334,267
Long-term finance leases	16,797	17,439
Long-term debt	2,239,406	2,233,281
Deferred income taxes	451,970	447,986
Noncurrent regulatory liabilities	456,824	451,483
Other noncurrent liabilities	393,155	387,152
Total Liabilities	3,906,467	3,871,608
Commitments and Contingencies (Note 9)		
Shareholders' Equity:		
Common stock, par value \$0.01; authorized 200,000,000 shares; issued and outstanding 54,144,775 and 50,566,520 shares, respectively; Preferred stock, par value \$0.01; authorized 50,000,000 shares; none issued	541	541
Treasury stock at cost	(98,644)	(96,015)
Paid-in capital	1,512,148	1,508,970
Retained earnings	655,865	635,246
Accumulated other comprehensive loss	(9,434)	(9,648)
Total Shareholders' Equity	2,060,476	2,039,094
Total Liabilities and Shareholders' Equity	\$ 5,966,943	\$ 5,910,702

See Notes to Condensed Consolidated Financial Statements

NORTHWESTERN CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)
(in thousands)

	Three Months Ended March 31,	
	2020	2019
OPERATING ACTIVITIES:		
Net income	\$ 50,704	\$ 72,806
Items not affecting cash:		
Depreciation and depletion	45,265	45,584
Amortization of debt issue costs, discount and deferred hedge gain	1,167	1,157
Stock-based compensation costs	3,042	2,418
Equity portion of allowance for funds used during construction	(895)	(969)
Loss (gain) on disposition of assets	7	(164)
Deferred income taxes	170	708
Changes in current assets and liabilities:		
Accounts receivable	11,494	(7,267)
Inventories	689	3,260
Other current assets	2,470	984
Accounts payable	(6,379)	3,954
Accrued expenses	35,810	27,781
Regulatory assets	9,845	(11,700)
Regulatory liabilities	8,259	(23,509)
Other noncurrent assets	(802)	(1,216)
Other noncurrent liabilities	(2,684)	(2,403)
Cash Provided by Operating Activities	158,162	111,424
INVESTING ACTIVITIES:		
Property, plant, and equipment additions	(78,371)	(65,577)
Cash Used in Investing Activities	(78,371)	(65,577)
FINANCING ACTIVITIES:		
Treasury stock activity	(2,492)	797
Dividends on common stock	(30,085)	(28,781)
Line of credit borrowings (repayments), net	6,000	(22,000)
Financing costs	(141)	(140)
Cash Used in Financing Activities	(26,718)	(50,124)
Increase (Decrease) in Cash, Cash Equivalents, and Restricted Cash	53,073	(4,277)
Cash, Cash Equivalents, and Restricted Cash, beginning of period	12,070	15,311
Cash, Cash Equivalents, and Restricted Cash, end of period	\$ 65,143	\$ 11,034
Supplemental Cash Flow Information:		
Cash paid during the period for:		
Income taxes	\$ 55	\$ 68
Interest	14,554	13,278
Significant non-cash transactions:		
Capital expenditures included in accounts payable	10,008	12,643

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 March 31,							
	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, 2018	53,889	3,566	\$ 539	\$ (95,546)	\$1,499,070	\$548,253	\$ (9,934)	\$ 1,942,382
Net income	—	—	—	—	—	72,806	—	72,806
Foreign currency translation adjustment	—	—	—	—	—	—	63	63
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	112	112
Stock-based compensation	86	25	—	(1,646)	2,406	—	—	760
Issuance of shares	21	(35)	1	932	1,517	—	—	2,450
Dividends on common stock (\$0.575 per share)	—	—	—	—	—	(28,781)	—	(28,781)
Balance at March 31, 2019	53,996	3,556	\$ 540	\$ (96,260)	\$1,502,993	\$592,278	\$ (9,759)	\$ 1,989,792
Balance at December 31, 2019	53,999	3,547	\$ 541	\$ (96,015)	\$1,508,970	\$635,246	\$ (9,648)	\$ 2,039,094
Net income	—	—	—	—	—	50,704	—	50,704
Foreign currency translation adjustment	—	—	—	—	—	—	101	101
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	113	113
Stock-based compensation	146	35	—	(2,741)	3,031	—	—	290
Issuance of shares	—	(4)	—	112	147	—	—	259
Dividends on common stock (\$0.60 per share)	—	—	—	—	—	(30,085)	—	(30,085)
Balance at March 31, 2020	54,145	3,578	\$ 541	\$ (98,644)	\$1,512,148	\$655,865	\$ (9,434)	\$ 2,060,476

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 734,800 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 March 31, 2020, 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, 2019](#).

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, as of March 31, 2020 our estimated gross contractual payments aggregate approximately \$136.3 million through 2024.

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):

	March 31, 2020	December 31, 2019	March 31, 2019	December 31, 2018
Cash and cash equivalents	\$ 56,393	\$ 5,145	\$ 3,959	\$ 7,860
Restricted cash	8,750	6,925	7,075	7,451
Total cash, cash equivalents, and restricted cash shown in the Condensed Consolidated Statements of Cash Flows	\$ 65,143	\$ 12,070	\$ 11,034	\$ 15,311

(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. 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. The MPSC issued a Final Order in December 2019, accepting the settlement, resulting 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 \$9.3 million. In addition to approving the settlement, the MPSC approved a pilot decoupling mechanism with no adjustment to ROE.

The Montana Consumer Counsel (MCC) filed a motion for reconsideration of several aspects of the Final Order. In particular, the MCC opposed the pilot decoupling mechanism and our methodology for determining the amount of revenue credited to Montana retail customers from our Federal Energy Regulatory Commission (FERC) transmission service rates. The MCC argued in the alternative that, if the MPSC does not eliminate the pilot decoupling mechanism, the MPSC should reduce ROE by 0.25%. We expect the MPSC to issue an Order on Reconsideration during the second quarter of 2020.

We implemented final rates, consistent with the Final Order, and began refunding interim rate revenue collected in excess of the stipulated revenue requirement effective March 1, 2020. As of March 31, 2020, and December 31, 2019, we had deferred revenue of approximately \$6.5 million and \$2.9 million, respectively, in the Condensed Consolidated Balance Sheets.

FERC Filing - Montana Transmission Service Rates

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 and settlement negotiations are ongoing.

Cost Recovery Mechanisms - Montana

Montana Electric and Natural Gas Supply Cost Trackers - 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 a new design for our electric tracker 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 above or below the baseline are allocated 90% to customers and 10% to shareholders, with an annual adjustment. The initial design of 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.

We submitted our annual PCCAM filing in September 2019, requesting recovery of approximately \$23.8 million in costs for the period July 1, 2018 to June 30, 2019, with the under recovery being collected over the 12-month period October 1, 2019

through September 30, 2020. The MCC and the Montana Environmental Information Center (MEIC) submitted testimony advocating for a disallowance of approximately \$6.0 million of replacement power costs incurred during a 2018 third quarter intermittent outage at our Colstrip generating facility due to an exceedance of air permit limits. In addition, the MCC advocated for a prorated application of the May 2019 statutory change eliminating the deadband and removing QF costs from the sharing calculation, which would result in an additional under recovery of costs of approximately \$4.0 million. The MPSC scheduled a hearing in this matter for June 2020. We began collecting costs for the July 2018 - June 2019 PCCAM period on October 1, 2019. As of March 31, 2020, the remaining under collection of approximately \$13.2 million was reflected in regulatory assets in the Condensed Consolidated Balance Sheets.

Montana Property Tax Tracker - Under Montana law, we are allowed to track the changes in the actual level of state and local taxes and fees and recover the increase in taxes and fees, net of the associated income tax benefit. We submit an annual property tax tracker filing with the MPSC for an automatic rate adjustment, with rates typically effective January 1st of each year. In February 2020, we amended our December 2019 filing in order to make corrections. We and the MCC agreed to a briefing schedule in this docket concluding in May 2020. We expect the MPSC to issue an order on the rate adjustment in the second quarter of 2020.

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 MPSC 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 MEIC, 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. The matter is fully briefed and the Montana Supreme Court held oral argument in the case on February 26, 2020. We are awaiting the Montana Supreme Court's decision.

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. Briefing on the matter is complete and we are awaiting a decision from the Montana Supreme Court.

Montana Community Renewable Energy Projects (CREPs)

We were required to acquire, as of December 31, 2019, approximately 66 MW of CREPs. While we have made progress towards meeting this obligation by acquiring approximately 36 MW of CREPs, we have been unable to acquire the remaining MWs required for various reasons, including the fact that proposed projects fail to qualify as CREPs or do not meet the statutory cost cap. The MPSC granted us waivers for 2012 through 2016. The validity of the MPSC's action as it related to waivers granted for 2015 and 2016 has been challenged legally and briefing is currently taking place before the Montana Supreme Court. We expect to file waiver requests for 2017, 2018, and 2019 as well, after resolution of that litigation. If the Court rules that the 2015 and 2016 waivers were invalid or if the requested waivers for 2017 through 2019 are not granted, we may be liable for penalties, although we believe the statutory penalty for failure to acquire sufficient energy does not apply to the acquisition of CREP resources. If the MPSC imposes a penalty, the amount of the penalty would depend on how the MPSC calculated the energy that a CREP would have produced.

(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 differences between our effective tax rate and the federal statutory rate (in thousands):

	Three Months Ended March 31,			
	2020		2019	
Income Before Income Taxes	\$ 48,898		\$ 74,379	
Income tax calculated at federal statutory rate	10,268	21.0 %	15,620	21.0%
Permanent or flow-through adjustments:				
State income tax, net of federal provisions	22	—	928	1.2
Flow-through repairs deductions	(7,438)	(15.2)	(7,935)	(10.7)
Production tax credits	(3,611)	(7.4)	(4,432)	(6.0)
Share-based compensation	(609)	(1.2)	186	0.3
Amortization of excess deferred income tax	(356)	(0.7)	(1,376)	(1.8)
Plant and depreciation of flow-through items	137	0.3	(1,523)	(2.0)
Recognition of unrecognized tax benefit	—	—	376	0.5
Other, net	(219)	(0.5)	(271)	(0.4)
	(12,074)	(24.7)	(14,047)	(18.9)
Income tax (benefit) expense	\$ (1,806)	(3.7)%	\$ 1,573	2.1%

Coronavirus Aid, Relief, and Economic Security Act (the CARES Act)

In response to COVID-19, on March 27, 2020, President Donald Trump signed into law the CARES Act. We evaluated the provisions of the CARES Act as of March 31, 2020, with no material effect on the financial statements. Certain tax provisions may result in immaterial cash refunds.

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. We have unrecognized tax benefits of approximately \$34.7 million as of March 31, 2020, including approximately \$28.0 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 of March 31, 2020, we do not have any amounts accrued for the payment of interest and penalties. During the three months ended March 31, 2019, we recognized \$0.4 million of expense for interest and penalties in the Condensed Consolidated Statements of Income.

Tax years 2016 and forward remain subject to examination by the Internal Revenue Service (IRS) and state taxing authorities. In addition, the available federal net operating loss carryforward may be reduced by the IRS for losses originating in certain tax years from 2002 forward.

(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					
	March 31, 2020			March 31, 2019		
	Before-Tax Amount	Tax Expense	Net-of-Tax Amount	Before-Tax Amount	Tax Expense	Net-of-Tax Amount
Foreign currency translation adjustment	\$ 101	\$ —	\$ 101	\$ 63	\$ —	\$ 63
Reclassification of net income (loss) on derivative instruments	153	(40)	113	153	(41)	112
Other comprehensive income (loss)	<u>\$ 254</u>	<u>\$ (40)</u>	<u>\$ 214</u>	<u>\$ 216</u>	<u>\$ (41)</u>	<u>\$ 175</u>

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

	March 31, 2020	December 31, 2019
Foreign currency translation	\$ 1,514	\$ 1,413
Derivative instruments designated as cash flow hedges	(11,068)	(11,181)
Postretirement medical plans	120	120
Accumulated other comprehensive loss	<u>\$ (9,434)</u>	<u>\$ (9,648)</u>

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

	Three Months Ended				
	March 31, 2020				
	Affected Line Item in the Condensed Statements of Income	Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Pension and Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		\$ (11,181)	\$ 120	\$ 1,413	\$ (9,648)
Other comprehensive income before reclassifications		—	—	101	101
Amounts reclassified from AOCL	Interest Expense	113	—	—	113
Net current-period other comprehensive income		113	—	101	214
Ending balance		<u>\$ (11,068)</u>	<u>\$ 120</u>	<u>\$ 1,514</u>	<u>\$ (9,434)</u>

**Three Months Ended
March 31, 2019**

	Affected Line Item in the Condensed Statements of Income	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		—	—	63	63
Amounts reclassified from AOCL	Interest Expense	112	—	—	112
Net current-period other comprehensive income		112	—	63	175
Ending balance		<u>\$ (11,521)</u>	<u>\$ 251</u>	<u>\$ 1,511</u>	<u>\$ (9,759)</u>

(5) 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

March 31, 2020	Electric	Gas	Other	Eliminations	Total
Operating revenues	\$ 244,625	\$ 90,630	\$ —	\$ —	\$ 335,255
Cost of sales	63,834	27,438	—	—	91,272
Gross margin	180,791	63,192	—	—	243,983
Operating, general and administrative	58,888	22,301	(2,184)	—	79,005
Property and other taxes	34,736	9,761	2	—	44,499
Depreciation and depletion	37,176	8,089	—	—	45,265
Operating income	49,991	23,041	2,182	—	75,214
Interest expense, net	(20,816)	(1,604)	(1,914)	—	(24,334)
Other income (expense), net	613	95	(2,690)	—	(1,982)
Income tax benefit (expense)	656	(737)	1,887	—	1,806
Net income (loss)	\$ 30,444	\$ 20,795	\$ (535)	\$ —	\$ 50,704
Total assets	\$ 4,345,943	\$ 1,616,381	\$ 4,619	\$ —	\$ 5,966,943
Capital expenditures	\$ 63,348	\$ 15,023	\$ —	\$ —	\$ 78,371

Three Months Ended

March 31, 2019	Electric	Gas	Other	Eliminations	Total
Operating revenues	\$ 273,037	\$ 111,183	\$ —	\$ —	\$ 384,220
Cost of sales	76,994	38,741	—	—	115,735
Gross margin	196,043	72,442	—	—	268,485
Operating, general and administrative	57,783	21,008	2,301	—	81,092
Property and other taxes	35,047	9,740	2	—	44,789
Depreciation and depletion	38,051	7,533	—	—	45,584
Operating income (loss)	65,162	34,161	(2,303)	—	97,020
Interest expense, net	(19,535)	(1,510)	(2,745)	—	(23,790)
Other (expense) income, net	(561)	(477)	2,187	—	1,149
Income tax (expense) benefit	(1,809)	1,079	(843)	—	(1,573)
Net income (loss)	\$ 43,257	\$ 33,253	\$ (3,704)	\$ —	\$ 72,806
Total assets	\$ 4,544,043	\$ 1,151,929	\$ 4,683	\$ —	\$ 5,700,655
Capital expenditures	\$ 52,307	\$ 13,270	\$ —	\$ —	\$ 65,577

(6) 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 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 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					
	March 31, 2020			March 31, 2019		
	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Montana	\$ 88.6	\$ 38.3	\$ 126.9	\$ 94.1	\$ 45.6	\$ 139.7
South Dakota	18.9	10.3	29.2	18.0	13.1	31.1
Nebraska	—	7.7	7.7	—	9.6	9.6
Residential	107.5	56.3	163.8	112.1	68.3	180.4
Montana	86.0	19.2	105.2	86.7	23.0	109.7
South Dakota	26.5	7.3	33.8	23.2	9.2	32.4
Nebraska	—	4.0	4.0	—	5.3	5.3
Commercial	112.5	30.5	143.0	109.9	37.5	147.4
Industrial	8.8	0.3	9.1	11.6	0.5	12.1
Lighting, Governmental, Irrigation, and Interdepartmental	5.3	0.3	5.6	5.1	0.5	5.6
Total Customer Revenues	234.1	87.4	321.5	238.7	106.8	345.5
Other Tariff and Contract Based Revenues	14.9	9.6	24.5	16.2	10.2	26.4
Total Revenue from Contracts with Customers	249.0	97.0	346.0	254.9	117.0	371.9
Regulatory amortization	(4.4)	(6.4)	(10.8)	18.1	(5.8)	12.3
Total Revenues	\$ 244.6	\$ 90.6	\$ 335.2	\$ 273.0	\$ 111.2	\$ 384.2

(7) 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	
	March 31, 2020	March 31, 2019
Basic computation	50,506,794	50,380,839
<i>Dilutive effect of:</i>		
Performance share awards (1)	198,486	348,525
Diluted computation	<u>50,705,280</u>	<u>50,729,364</u>

(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.

(8) 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 (credit) for our pension and other postretirement plans consists of the following (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2020	2019	2020	2019
Components of Net Periodic Benefit Cost (Credit)				
Service cost	\$ 2,846	\$ 2,497	\$ 92	\$ 89
Interest cost	5,726	6,629	109	155
Expected return on plan assets	(6,545)	(6,362)	(247)	(218)
Amortization of prior service cost (credit)	—	1,652	(471)	(471)
Recognized actuarial loss (gain)	1,280	—	(18)	(24)
Net Periodic Benefit Cost (Credit)	<u>\$ 3,307</u>	<u>\$ 4,416</u>	<u>\$ (535)</u>	<u>\$ (469)</u>

We contributed \$1.4 million to our pension plans during the three months ended March 31, 2020. We expect to contribute an additional \$10.0 million to our pension plans during 2020.

(9) 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 \$29.2 million to \$31.9 million. As of March 31, 2020, we had a reserve of approximately \$29.9 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 \$24.0 million of our environmental reserve accrual is related to the following manufactured gas plants.

South Dakota - 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 March 31, 2020, the reserve for remediation costs at this site is approximately \$8.1 million, and we estimate that approximately \$2.8 million of this amount will be incurred during the next five years.

Nebraska - We 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.

Montana - 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.

MDEQ has indicated it expects to proceed in listing the Missoula site as a Montana superfund site. After researching historical ownership we have identified another potentially responsible party with whom we have entered into an agreement allocating third-party costs to be incurred in addressing the site. The other party is assuming the lead role at 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.

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. The MDEQ approved the RIWP in March 2020 and we expect work at the Helena site to be ongoing in 2020.

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 (CO₂). These actions include legislative proposals, Executive and Environmental Protection Agency (EPA) actions at the federal level, actions at the state level, investor activism 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, Congress has not passed any federal climate change legislation and we cannot predict the timing or form of any potential legislation. In 2019, the EPA finalized the Affordable Clean Energy Rule (ACE), which repealed the 2015 Clean Power Plan (CPP) in regulating GHG emissions from coal-fired plants. Various challenges to ACE are pending in the District of Columbia Circuit (D.C. Circuit).

Generally, ACE provides more regulatory flexibility to individual states and likely will not reduce CO₂ emissions as much as the CPP. Under the ACE, states must establish unit-specific standards that reflect emissions achievable through heat rate improvements, which the 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 the EPA and coal-fired plants will have two additional years to comply with the standards.

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 could result in additional compliance costs impacting 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.

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 on us until state plans are adopted and any judicial reviews are completed.

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 (CAA) that could require the installation of emission control equipment at the generation plants in which we have joint ownership. Air emissions at our thermal generating plants are managed by the use of emissions and combustion controls and monitoring, and sulfur dioxide allowances. These measures are anticipated to be sufficient to permit the facilities to continue to meet current air emissions compliance requirements.

Regional Haze Rules - In January 2017, the EPA published amendments to the requirements under the CAA for state plans for protection of visibility - regional haze rules. 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.

By 2021, Montana, or the 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 the EPA's request to hold the case in abeyance while the EPA considers further administrative action to revisit the rule.

In North Dakota, the Coyote facility was assessed in 2010 and did not require additional emissions controls. The facility is expected to be reassessed in 2020 by the North Dakota Department of Environmental Quality (ND DEQ). Once the ND DEQ establishes a strategy for regional haze compliance, the joint owners will assess the requirements, if any, and determine whether to move forward with the installation of additional emissions controls.

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.

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 is scheduled to begin on June 2, 2020.

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 may be subject to appeal, that appeal would not likely occur until after judgment in the case. On February 12, 2019, the Federal District Court granted our motion to join the United States as a defendant to the litigation. As a result, on October 31, 2019, the State filed and served an Amended Complaint including the United States as a defendant. We and Talen filed answers to the Amended Complaint on December 13, 2019, and the United States answered on February 5, 2020. On April 16, 2020 the Federal District Court set a scheduling conference for June 11, 2020 to develop a plan for discovery and schedule for disposition of the case.

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 734,800 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, 2019](#).

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 months ended March 31, 2020 and 2019.

HOW WE PERFORMED AGAINST OUR FIRST QUARTER 2019 RESULTS

	Three months ended March 31, 2020 vs. 2019		
	Income Before Income Taxes	Income Tax (Expense) Benefit	Net Income
	(in millions)		
First Quarter 2019	\$ 74.4	\$ (1.6)	\$ 72.8
<i>Items (decreasing) increasing net income:</i>			
Lower electric retail volumes	(8.7)	2.2	(6.5)
Lower natural gas retail volumes	(8.4)	2.1	(6.3)
Higher operating, general, and administrative expenses impacting net income	(1.8)	0.5	(1.3)
Lower Montana electric transmission revenue	(1.2)	0.3	(0.9)
Lower Montana natural gas rates	(0.6)	0.2	(0.4)
Higher Montana electric retail rates	1.6	(0.4)	1.2
Lower depreciation and depletion	0.3	(0.1)	0.2
Other	(6.7)	(1.4)	(8.1)
First Quarter 2020	\$ 48.9	\$ 1.8	\$ 50.7
Change in Net Income			\$ (22.1)

Consolidated net income for the three months ended March 31, 2020 was \$50.7 million as compared with \$72.8 million for the same period in 2019. This decrease was primarily due to lower loads in our electric and natural gas segments due to warmer winter weather, higher operating, general and administrative costs impacting net income, and lower transmission revenue, offset in part by an increase in Montana electric retail rates.

Following is a brief overview of significant items for 2020.

SIGNIFICANT TRENDS AND REGULATION

COVID-19 Pandemic

We are one of many companies providing essential services during this national emergency related to the COVID-19 pandemic. We implemented a comprehensive set of actions to help our customers, communities, and employees, while maintaining our commitments to provide reliable service and to continue to monitor and adapt our financial business plan for the evolving COVID-19 challenges. In addition to announcing an incremental \$300,000 in charitable contributions and aid to assist the communities we serve, we have taken extra precautions for our employees who work in the field and for employees who continue to work in our facilities, and we have implemented work from home policies where appropriate. Currently, we do not anticipate any employee layoffs and are continuing to hire for critical positions to maintain our high level of reliability and customer service. We continue to implement strong physical and cyber-security measures to ensure that our systems remain functional in order to serve our operational needs with a remote workforce and to keep our operations running to ensure uninterrupted service to our customers. We have informed both our retail customers and state regulators that disconnections for non-payment will be temporarily suspended. Our level of service to our 734,800 customers remains uninterrupted.

In response to COVID-19, President Donald Trump signed into law the CARES Act on March 27, 2020. The CARES Act provides numerous tax provisions and other stimulus measures, including temporary changes regarding the prior and future utilization of net operating losses, temporary changes to the prior and future limitations on interest deductions, temporary suspension of certain payment requirements for the employer portion of Social Security taxes, technical corrections from prior tax legislation for tax depreciation of certain qualified improvement property, and the creation of certain refundable employee retention credits. We evaluated the provisions of the CARES Act and do not anticipate the associated impacts, if any, will have a material effect on our financial position or liquidity.

2020 Outlook - This is a rapidly evolving situation that could lead to extended disruption of economic activity. We have not experienced major declines in customer usage across our business related to COVID-19. Nonetheless, as a result of the spread of COVID-19 in our service territories, business curtailments, 'shelter in place' or 'stay at home' orders and travel restrictions, we may experience impacts to our financial results going forward. In addition, while we have not experienced significant supply chain issues, so far, we continue to closely manage and monitor developments in our supply chain. There may also be material delays in scheduling proceedings and hearings, and in obtaining orders from federal and state courts and regulatory agencies; these delays could negatively affect us financially. An extended slowdown of the United States' economic growth, demand for commodities and/or material changes in governmental policy could result in lower economic growth and lower demand for electricity and natural gas as well as the ability of various customers, contractors, suppliers and other business partners to fulfill their obligations, which could have a material adverse effect on our results of operations, financial condition and prospects.

If the situation leads to an extended disruption of economic activity in our service territories, we would expect to be negatively impacted by lower sales volumes, increased operating expenses due primarily to an increase in uncollectible accounts, and higher interest expense offset in part by cost control. At this time, we cannot predict the ultimate impact of COVID-19 on our results of operations, financial condition and prospects. The likelihood these events would materially impact our future financial results will increase the longer business curtailments, 'shelter in place' or 'stay at home' orders and travel restrictions remain in place.

We remain on track for our approximately \$400 million capital investment as disclosed in our annual report on Form 10-K. However, the progression of and global response to the COVID-19 outbreak increases the risk of delays in construction activities and equipment deliveries related to our capital projects, including potential delays in obtaining permits from government agencies, resulting in a potential deferral of capital expenditures. Given the rapid and evolving nature of the COVID-19 matter, the extent of any such impacts is uncertain.

Liquidity - We continue to maintain adequate liquidity to operate our business and fund our ongoing capital program. As of March 31, 2020, our total net liquidity was approximately \$186.4 million, including \$56.4 million of cash and \$130.0 million of revolving credit facility availability. Our \$400 million revolving credit facility, which expires December 12, 2021, contains an accordion feature that allows us to increase our liquidity another \$25 million under certain conditions. We also have a \$25 million credit facility that provides swing-line borrowing capability, which expires March 27, 2022.

Subsequent to the three months ended March 31, 2020, as a precautionary measure in order to increase our cash position and preserve financial flexibility in light of uncertainty in the markets, we accessed the capital markets in two transactions:

- On April 3, 2020, we entered into a \$100 million 364-Day Term Loan Credit Agreement (Term Loan), with two of our relationship banks, and borrowed the full amount under the Term Loan. Borrowings from this facility allow us to meet our temporarily increased targeted minimum liquidity threshold of \$200 million, up from our long-standing \$100 million level; and
- On April 14 2020, we priced \$150 million principal amount 10-year, 3.21% first mortgage bonds and expect to complete the bond issuance in May 2020.

For further discussion of these transactions see the *Liquidity and Capital Resources* discussion. As previously disclosed, we are contemplating an equity issuance in late 2020 or early 2021 to maintain and protect our current credit ratings in balance with our current capital expenditure plans. Potential business disruptions and deterioration of the capital markets stemming from the COVID-19 pandemic could delay our contemplated equity issuance into 2021.

Proposed Colstrip Unit 4 Capacity Acquisition

In February 2020, we filed an application with the MPSC for pre-approval to acquire Puget Sound Energy's (Puget) 25% interest, 185 MW of generation, in Colstrip Unit 4 for one dollar. In addition, we sought approval to sell 90 MW of energy to Puget through a Power Purchase Agreement for roughly 5 years at a price indexed to hourly prices at the Mid-Columbia power hub, with a price floor reflecting the recovery of fixed operating and maintenance costs and variable generation costs. Our proposal included zero net effect on customer bills while setting aside benefits from the transaction - estimated to be \$4 million annually - to address environmental compliance, remediation and decommissioning costs associated with our existing 222 MW ownership interest in Colstrip Unit 4. Puget remains responsible for its presale 25% ownership share of all costs for remediation of existing environmental conditions and decommissioning regardless of the proposed acquisition or when Colstrip Unit 4 is retired.

Under the Ownership and Operation Agreement to which each of the Colstrip Units 3 and 4 co-owners are a party, each co-owner has a right of first refusal to our transaction with Puget. On April 8, 2020 and on April 15, 2020, Talen provided notices of its exercise of its right of first refusal to acquire a proportionate share of Puget's interest in Colstrip Unit 4, which would reduce our proposed transaction to 92.5 MW, and the sale of energy to Puget to 45 MW. We expect to supplement our application with the MPSC by the end of April 2020 to reflect this development. Should the MPSC decline to grant our application in all material respects, then we have the right, under the purchase and sale agreement with Puget, to terminate the transaction.

We expect the MPSC to establish a procedural schedule in this docket in the second quarter of 2020. If this capacity acquisition is approved and we acquire 92.5 MW from Puget, this is expected to reduce our need for capacity identified in our resource plan by 80 MW, which is based on resource adequacy requirements.

We also entered into an agreement with Puget to acquire an additional 95 MW interest in the 500 kilovolt (kV) Colstrip Transmission System for net book value at the time of the sale. The net book value is expected to range between \$2.5 million to \$3.8 million. After the roughly 5-year power purchase agreement with Puget, we will have the option to acquire another 90 MW interest in the 500 kV Colstrip Transmission System for net book value at that time. These transmission acquisitions are conditioned upon approval and closing of the Colstrip Unit 4 acquisition. Talen, while not a co-owner of the Colstrip Transmission System, has asserted that its right of first refusal as to the Colstrip Unit 4 transaction extends to the transmission portion of the transaction. We disagree with the assertion in this regard and will oppose Talen's efforts to obtain an interest in the Colstrip Transmission System.

Recovery of the additional rate base from these transactions, if completed, will be subject to review in the next Montana general electric rate case.

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. The following discussion includes a reconciliation of Gross Margin to Operating Revenues, the most directly comparable GAAP measure.

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 March 31, 2020 Compared with the Three Months Ended March 31, 2019

Consolidated net income for the three months ended March 31, 2020 was \$50.7 million as compared with \$72.8 million for the same period in 2019. This decrease was primarily due to lower loads in our electric and natural gas segments due to warmer winter weather and lower transmission revenue, offset in part by an increase in Montana electric retail rates and customer growth.

Consolidated operating revenues for the three months ended March 31, 2020 were \$335.3 million as compared with \$384.2 million for the same period in 2019. This decrease was primarily due to lower volumes from warmer winter weather, partly offset by customer growth. Consolidated gross margin for the three months ended March 31, 2020 was \$244.0 million as compared with \$268.5 million for the same period in 2019, a decrease of \$24.5 million.

	Electric		Natural Gas		Total	
	2020	2019	2020	2019	2020	2019

(dollars in millions)

Reconciliation of operating revenue to gross margin:

Operating Revenues	\$ 244.6	\$ 273.0	\$ 90.6	\$ 111.2	\$ 335.2	\$ 384.2
Cost of Sales	63.8	77.0	27.4	38.7	91.2	115.7
Gross Margin⁽¹⁾	\$ 180.8	\$ 196.0	\$ 63.2	\$ 72.5	\$ 244.0	\$ 268.5

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

	Three Months Ended March 31,			
	2020	2019	Change	% Change

(dollars in millions)

Gross Margin

Electric	\$ 180.8	\$ 196.0	\$ (15.2)	(7.8)%
Natural Gas	63.2	72.5	(9.3)	(12.8)
Total Gross Margin⁽¹⁾	\$ 244.0	\$ 268.5	\$ (24.5)	(9.1)%

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

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

	<u>Gross Margin 2020 vs. 2019</u>	
Gross Margin Items Impacting Net Income		
Electric retail volumes	\$	(8.7)
Natural gas retail volumes		(8.4)
Electric transmission		(1.2)
Montana natural gas rates		(0.6)
Montana electric retail rates		1.6
Other		(4.9)
Change in Gross Margin Impacting Net Income		(22.2)
Gross Margin Items Offset Within Net Income		
Production tax credits flowed-through trackers		(1.9)
Operating expenses recovered in trackers		(0.7)
Property taxes recovered in trackers		0.3
Change in Gross Margin Items Offset Within Net Income		(2.3)
Decrease in Consolidated Gross Margin⁽¹⁾	\$	(24.5)

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

Consolidated gross margin for items impacting net income decreased \$22.2 million due to the following items:

- A decrease in electric volumes for our residential and commercial customers due to warmer winter weather, primarily in our Montana jurisdiction;
- A decrease in gas volumes due primarily to warmer winter weather and lower customer usage, offset in part by customer growth;
- Lower demand to transmit energy across our transmission lines due to market conditions and pricing;
- A decrease in Montana natural gas rates associated with the annual step down for our Montana gas production assets; and
- A decrease in other due primarily to nonrecurring items.

These decreases were partly offset by an increase in Montana electric retail rates.

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

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

	<u>Three Months Ended March 31,</u>			
	<u>2020</u>	<u>2019</u>	<u>Change</u>	<u>% Change</u>
	(dollars in millions)			
Operating Expenses (excluding cost of sales)				
Operating, general and administrative	\$ 79.0	\$ 81.1	\$ (2.1)	(2.6)%
Property and other taxes	44.5	44.8	(0.3)	(0.7)
Depreciation and depletion	45.3	45.6	(0.3)	(0.7)
	\$ 168.8	\$ 171.5	\$ (2.7)	(1.6)%

Consolidated operating, general and administrative expenses were \$79.0 million for the three months ended March 31, 2020, as compared with \$81.1 million for the three months ended March 31, 2019. Primary components of the change include the following (in millions):

	Operating, General & Administrative Expenses
	2020 vs. 2019
Operating, General & Administrative Expenses Impacting Net Income	
Generation costs	\$ 1.4
Other	0.4
Change in Items Impacting Net Income	1.8
Operating, General & Administrative Expenses Offset Within Net Income	
Pension and other postretirement benefits	1.7
Operating expenses recovered in trackers	(0.7)
Non-employee directors deferred compensation	(4.9)
Change in Operating, General & Administrative Expense Items Offset Within Net Income	(3.9)
Decrease in Operating, General & Administrative Expenses	\$ (2.1)

Consolidated operating, general and administrative expenses for items impacting net income increased \$1.8 million, which includes increased costs associated with our Montana generation resource plan request for proposal process and other maintenance.

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 \$44.5 million for the three months ended March 31, 2020, as compared with \$44.8 million in the same period of 2019. This slight decrease was due primarily to lower MPSC tax and invasive species tax, offset in part by an increase in Montana state and local taxes. We estimate property taxes throughout each year, and update those estimates 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 \$45.3 million for the three months ended March 31, 2020, as compared with \$45.6 million in the same period of 2019. This slight decrease was primarily due to a depreciation adjustment consistent with the final order in our Montana electric rate case, partly offset by plant additions.

Consolidated operating income for the three months ended March 31, 2020 was \$75.2 million as compared with \$97.0 million in the same period of 2019. This decrease was primarily due to the decrease in gross margin discussed above.

Consolidated interest expense for the three months ended March 31, 2020 was \$24.3 million as compared with \$23.8 million in the same period of 2019, due primarily to higher borrowings.

Consolidated other expense was \$2.0 million for the three months ended March 31, 2020 as compared to other income of \$1.1 million during the same period of 2019. This change includes a \$4.9 million decrease in the value of deferred shares held in trust for non-employee directors deferred compensation, partially offset by a decrease in other pension expense of \$1.7 million, both of which are offset in operating, general, and administrative expense with no impact to net income.

Consolidated income tax benefit for the three months ended March 31, 2020 was \$1.8 million as compared with income tax expense of \$1.6 million in the same period of 2019. Our effective tax rate for the three months ended March 31, 2020 was

(3.7)% as compared with 2.1% for the same period in 2019. We expect our effective tax rate to range between (5)% to 0% in 2020.

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

	Three Months Ended March 31,			
	2020		2019	
Income Before Income Taxes	\$	48.9	\$	74.4
Income tax calculated at federal statutory rate		10.3	21.0 %	15.6 21.0%
Permanent or flow-through adjustments:				
State income tax, net of federal provisions		—	—	0.9 1.2
Flow-through repairs deductions		(7.4)	(15.2)	(7.9) (10.7)
Production tax credits		(3.6)	(7.4)	(4.4) (6.0)
Share-based compensation		(0.6)	(1.2)	0.2 0.3
Amortization of excess deferred income tax		(0.4)	(0.7)	(1.4) (1.8)
Plant and depreciation of flow-through items		0.1	0.3	(1.5) (2.0)
Recognition of unrecognized tax benefit		—	—	0.4 0.5
Other, net		(0.2)	(0.5)	(0.3) (0.4)
		<u>(12.1)</u>	<u>(24.7)</u>	<u>(14.0)</u> <u>(18.9)</u>
Income tax (benefit) expense	\$	(1.8)	(3.7)%	\$ 1.6 2.1%

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 March 31, 2020 was \$50.7 million as compared with \$72.8 million for the same period in 2019. This decrease was primarily due to lower gross margin.

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 March 31, 2020 Compared with the Three Months Ended March 31, 2019

	Results			
	2020	2019	Change	% Change
	(dollars in millions)			
Retail revenues	\$ 234.1	\$ 238.7	\$ (4.6)	(1.9)%
Regulatory amortization	(3.6)	19.1	(22.7)	(118.8)
Total retail revenues	230.5	257.8	(27.3)	(10.6)
Transmission	12.6	13.5	(0.9)	(6.7)
Wholesale and Other	1.5	1.7	(0.2)	(11.8)
Total Revenues	244.6	273.0	(28.4)	(10.4)
Total Cost of Sales	63.8	77.0	(13.2)	(17.1)
Gross Margin⁽¹⁾	\$ 180.8	\$ 196.0	\$ (15.2)	(7.8)%

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

	Revenues		Megawatt Hours (MWH)		Avg. Customer Counts	
	2020	2019	2020	2019	2020	2019
	(in thousands)					
Montana	\$ 88,639	\$ 94,096	734	807	305,969	302,158
South Dakota	18,918	18,015	180	196	50,642	50,670
Residential	107,557	112,111	914	1,003	356,611	352,828
Montana	86,005	86,710	791	816	69,691	68,263
South Dakota	26,495	23,160	291	284	12,735	12,770
Commercial	112,500	109,870	1,082	1,100	82,426	81,033
Industrial	8,759	11,581	675	701	78	77
Other	5,249	5,147	21	23	4,805	4,799
Total Retail Electric	\$ 234,065	\$ 238,709	2,692	2,827	443,920	438,737

	Heating Degree Days			2020 as compared with:	
	2020	2019	Historic Average	2019	Historic Average
Montana	3,128	4,062	3,209	23% warmer	3% warmer
South Dakota	4,029	4,661	4,060	14% warmer	1% warmer

The following summarizes the components of the changes in electric gross margin for the three months ended March 31, 2020 and 2019 (in millions):

	<u>Gross Margin 2020 vs. 2019</u>	
Gross Margin Items Impacting Net Income		
Retail volumes	\$	(8.7)
Transmission		(1.2)
Montana electric rates		1.6
Other		(4.9)
Change in Gross Margin Impacting Net Income		<u>(13.2)</u>
Gross Margin Items Offset Within Net Income		
Production tax credits flowed-through trackers		(1.9)
Operating expenses recovered in trackers		(0.8)
Property taxes recovered in trackers		0.7
Change in Gross Margin Items Offset Within Net Income		<u>(2.0)</u>
Decrease in Gross Margin⁽¹⁾	\$	<u>(15.2)</u>

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

Gross margin for items impacting net income decreased \$13.2 million primarily due to the following items:

- A decrease in electric volumes for our residential and commercial customers due to warmer winter weather, primarily in our Montana jurisdiction;
- Lower demand to transmit energy across our transmission lines due to market conditions and pricing; and
- A decrease in other due primarily to nonrecurring items.

These decreases were partly offset by an increase in Montana electric rates.

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

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

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 March 31, 2020 Compared with the Three Months Ended March 31, 2019

	Results			
	2020	2019	Change	% Change
	(dollars in millions)			
Retail revenues	\$ 87.4	\$ 106.8	\$ (19.4)	(18.2)%
Regulatory amortization	(6.4)	(5.3)	(1.1)	20.8
Total retail revenues	81.0	101.5	(20.5)	(20.2)
Wholesale and other	9.6	9.7	(0.1)	(1.0)
Total Revenues	90.6	111.2	(20.6)	(18.5)
Total Cost of Sales	27.4	38.7	(11.3)	(29.2)
Gross Margin⁽¹⁾	\$ 63.2	\$ 72.5	\$ (9.3)	(12.8)%

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

	Revenues		Dekatherms (Dkt)		Customer Counts	
	2020	2019	2020	2019	2020	2019
	(in thousands)					
Montana	\$ 38,295	\$ 45,638	5,637	6,875	176,607	174,470
South Dakota	10,271	13,042	1,584	1,747	40,589	40,302
Nebraska	7,687	9,640	1,295	1,497	37,622	37,634
Residential	56,253	68,320	8,516	10,119	254,818	252,406
Montana	19,154	23,017	2,923	3,599	24,464	24,199
South Dakota	7,294	9,207	1,592	1,605	6,917	6,841
Nebraska	4,061	5,300	889	1,050	5,000	4,922
Commercial	30,509	37,524	5,404	6,254	36,381	35,962
Industrial	340	482	53	77	233	241
Other	343	440	62	78	152	165
Total Retail Gas	\$ 87,445	\$ 106,766	14,035	16,528	291,584	288,774

	Heating Degree Days			2020 as compared with:	
	2020	2019	Historic Average	2019	Historic Average
Montana	3,136	4,052	3,302	23% warmer	5% warmer
South Dakota	4,029	4,661	4,060	14% warmer	1% warmer
Nebraska	3,074	3,634	3,370	15% warmer	9% warmer

The following summarizes the components of the changes in natural gas gross margin for the three months ended March 31, 2020 and 2019:

Gross Margin 2020 vs. 2019**(in millions)****Gross Margin Items Impacting Net Income**

Retail volumes	\$	(8.4)
Montana rates		(0.6)
Change in Gross Margin Impacting Net Income		(9.0)

Gross Margin Items Offset Within Net Income

Property taxes recovered in trackers		(0.4)
Operating expenses recovered in trackers		0.1
Change in Gross Margin Items Offset Within Net Income		(0.3)
Decrease in Gross Margin⁽¹⁾	\$	(9.3)

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

Gross margin for items impacting net income decreased \$9.0 million primarily due:

- A decrease in volumes due to warmer winter weather, offset in part by customer growth; and
- A reduction of rates from 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:

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

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

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, existing borrowing capacity, and issuance of debt securities 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.

Subsequent to the end of our first quarter, and as discussed above in the *Significant Trends and Regulation* section of Management's Discussion and Analysis, in response to the COVID-19 pandemic and as a precautionary measure in order to increase our cash position and preserve financial flexibility in light of current uncertainty in the markets, we entered into a \$100 million Term Loan. On April 3, 2020 we borrowed the full amount under the Term Loan and used the proceeds to pay down a portion of outstanding revolving credit facility borrowings and for general corporate purposes. The Term Loan bears interest at available rates tied to the Eurodollar rate plus a credit spread of 1.50%. All principal and unpaid interest under the Term Loan is due and payable on April 2, 2021. The Term Loan provides for prepayment of the principal and interest; however, amounts prepaid may not be reborrowed. The Term Loan requires us to maintain a consolidated indebtedness to total capitalization ratio of 65 percent or less. Failure to comply with this covenant would entitle the banks to terminate their lending commitments and to accelerate the maturity of all amounts outstanding. As of April 17, 2020, we were in compliance with this covenant.

In addition, in April 2020, we priced \$100 million principal amount of Montana First Mortgage Bonds and \$50 million principal amount of South Dakota First Mortgage Bonds, at a fixed interest rate of 3.21% maturing in 2030. We expect these transactions to close in May 2020.

Liquidity is provided by internal cash flows and the use of our credit facilities. We have a \$400 million revolving credit facility, a \$25 million revolving credit facility to provide swingline borrowing capability, and as discussed above entered into a \$100 million Term Loan in April 2020. 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 March 31, 2020, our total net liquidity was approximately \$186.4 million, including \$56.4 million of cash and \$130.0 million of revolving credit facility availability. As of March 31, 2020, there were no letters of credit outstanding and \$295.0 million in borrowings under our revolving credit facilities. Availability under our revolving credit facilities was \$265.0 million as of April 17, 2020.

We remain on track for our approximately \$400 million capital investment as disclosed in our annual report on Form 10-K. However, the progression of and global response to the COVID-19 outbreak increases the risk of delays in construction activities and equipment deliveries related to our capital projects, including potential delays in obtaining permits from government agencies, resulting in potential deferral of capital expenditures. Given the rapid and evolving nature of the COVID-19 pandemic, the extent of any such impacts is uncertain. We continue to monitor the disruption in capital markets caused by COVID-19. If conditions further deteriorate and we need to access the capital markets there can be no assurance that we will be able to obtain such financing on commercially reasonable terms or at all. In addition, as previously disclosed, we are contemplating an equity issuance in late 2020 or early 2021 to maintain and protect our current credit ratings in balance with our current capital expenditure plans. Potential business disruptions and deterioration of the capital markets stemming from the COVID-19 pandemic could delay our contemplated equity issuance into 2021.

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. 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 seasonal fluctuations discussed above; therefore 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 March 31, 2020, we have under collected our costs recovered through tracking mechanisms by approximately \$21.5 million. We under collected our costs by approximately \$32.5 million as of December 31, 2019 and under collected our costs by approximately \$26.1 million as of March 31, 2019.

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 April 17, 2020, 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):

	Three Months Ended March 31,	
	2020	2019
Operating Activities		
Net income	\$ 50.7	\$ 72.8
Non-cash adjustments to net income	48.7	48.7
Changes in working capital	62.2	(6.5)
Other noncurrent assets and liabilities	(3.5)	(3.6)
Cash Provided by Operating Activities	158.1	111.4
Investing Activities		
Property, plant and equipment additions	(78.4)	(65.6)
Cash Used in Investing Activities	(78.4)	(65.6)
Financing Activities		
Line of credit borrowings (repayments), net	6.0	(22.0)
Dividends on common stock	(30.1)	(28.8)
Financing costs	(0.1)	(0.1)
Other	(2.5)	0.8
Cash Used in Financing Activities	(26.7)	(50.1)
Increase (Decrease) in Cash, Cash Equivalents, and Restricted Cash	\$ 53.0	\$ (4.3)
Cash, Cash Equivalents, and Restricted Cash, beginning of period	\$ 12.1	\$ 15.3
Cash, Cash Equivalents, and Restricted Cash, end of period	\$ 65.1	\$ 11.0

Cash Provided by Operating Activities

As of March 31, 2020, cash, cash equivalents, and restricted cash were \$65.1 million as compared with \$12.1 million at December 31, 2019 and \$11.0 million at March 31, 2019. Cash provided by operating activities totaled \$158.1 million for the three months ended March 31, 2020 as compared with \$111.4 million during the three months ended March 31, 2019. This increase in operating cash flows is primarily due to improved collections of energy supply costs in the current period, as compared with higher procured supply costs and credits to Montana customers of approximately \$20.5 million in the first quarter of 2019. These improvements were offset in part by reduced net income.

Cash Used in Investing Activities

Cash used in investing activities increased by approximately \$12.8 million as compared with the first three months of 2019. Plant additions during the first three months of 2020 include maintenance additions of approximately \$54.5 million and capacity related capital expenditures of \$23.9 million. Plant additions during the first three months of 2019 included maintenance additions of approximately \$43.4 million, and capacity related capital expenditures of approximately \$22.2 million.

Cash Used in Financing Activities

Cash used in financing activities totaled \$26.7 million during the three months ended March 31, 2020 as compared with \$50.1 million during the three months ended March 31, 2019. During the three months ended March 31, 2020, cash used in financing activities reflects payment of dividends of \$30.1 million, offset in part by net issuances under our revolving lines of credit of \$6.0 million. During the three months ended March 31, 2019, net cash used in financing activities reflects net repayments under our revolving lines of credit of \$22.0 million and the payment of dividends of \$28.8 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 March 31, 2020. See our Annual Report on Form 10-K for the year ended December 31, 2019 for additional discussion.

	<u>Total</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>	<u>2024</u>	<u>Thereafter</u>
	(in thousands)						
Long-term debt (1)	\$ 2,251,637	\$ —	\$ 295,000	\$ —	\$ 144,660	\$ —	\$ 1,811,977
Finance leases	19,319	1,880	2,668	2,875	3,098	3,338	5,460
Estimated pension and other postretirement obligations (2)	64,187	11,614	13,491	13,209	13,097	12,776	NA
Qualifying facilities liability (3)	611,660	57,400	78,356	80,226	82,320	79,726	233,632
Supply and capacity contracts (4)	1,881,142	132,908	154,081	155,990	154,901	147,293	1,135,969
Contractual interest payments on debt (5)	1,498,770	66,137	84,043	77,602	76,397	74,709	1,119,882
Environmental remediation obligations (6)	4,323	2,265	912	720	213	213	NA
Total Commitments (7)	\$ 6,331,038	\$ 272,204	\$ 628,551	\$ 330,622	\$ 474,686	\$ 318,055	\$ 4,306,920

- (1) Represents cash payments for long-term debt and excludes \$12.2 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 \$611.7 million. A portion of the costs incurred to purchase this energy is recoverable through rates authorized by the MPSC, totaling approximately \$493.3 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 24 years.
- (5) Contractual interest payments includes our revolving credit facilities, which have a variable interest rate. We have assumed an average interest rate of 2.27% 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.

Other Obligations - As a co-owner of Colstrip, we provided surety bonds of approximately \$22.8 million and \$13.2 million as of March 31, 2020 and December 31, 2019, respectively, on behalf of the operator to ensure the operation and maintenance of remedial and closure actions are carried out related to the Administrative Order on Consent Regarding Impacts Related to Wastewater Facilities Comprising the Closed-Loop System at Colstrip Steam Electric Stations, Colstrip Montana (the AOC) as required by the MDEQ. It is currently anticipated that each co-owner of Colstrip will be required to post an additional amount of financial assurance to support additional performance by the operator of closure and remediation actions under the AOC. As costs are incurred under the AOC, the surety bonds will be reduced.

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, 2019](#). As of March 31, 2020, 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 and Term Loan. 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 March 31, 2020, we had approximately \$295.0 million in borrowings under our revolving credit facilities. A 1.0% increase in interest rates would increase our annual interest expense by approximately \$3.0 million.

In addition, in April 2020, we entered into a 364-day Term Loan and borrowed \$100 million, which bears interest at available rates tied to the Eurodollar rate plus a credit spread of 1.50%. A 1.0% increase in interest rates would increase interest expense by approximately \$1.0 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 prudence 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 9, 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.

The COVID-19 pandemic and resulting adverse economic conditions will likely have a negative impact on our business, financial condition and results of operations.

The actual or perceived effects of a disease outbreak, epidemic, pandemic or similar widespread public health concern, such as COVID-19, will likely negatively affect our operations, liquidity, financial condition and results of operations. While to date we have experienced no material negative effects on our business and results of operations as a result of the current COVID-19 outbreak, the situation remains dynamic and subject to rapid and possibly material change, which ultimately could result in material negative effects on our business and results of operations.

Economic - This is a rapidly evolving situation that could lead to extended disruption of economic activity. Prolonged unfavorable economic conditions, and any resulting recession or slowed economic growth, may result in lower demand for electricity and natural gas as well as the inability of various customers, contractors, suppliers and other business partners to fulfill their obligations. There can be no assurance that any decrease in revenues resulting from the COVID-19 pandemic will return to previous levels in the future. Decreases in per capita income and level of disposable income, increased unemployment or a decline in consumer confidence could have an adverse effect on our business. Certain of our customers have been, and may in the future be, required to close down or operate at a lower capacity, which may, as a result, adversely impact our business in the short term and may in the future materially adversely affect our business, financial condition and results of operations. While we cannot predict the ultimate impact of the COVID-19 pandemic, we expect our financial results to be impacted by lower sales volumes, increased operating expenses due primarily to an increase in reserves for uncollectible accounts due to the unprecedented economic disruption and discontinuance of customer disconnects, and an increase in interest expense. We continue to monitor the disruption in capital markets caused by COVID-19. If conditions further deteriorate and we need to access the capital markets there can be no assurance that we will be able to obtain such financing on commercially reasonable terms or at all.

Despite our efforts to manage these impacts, their ultimate impact is highly uncertain and subject to change, and also depends on factors beyond our knowledge or control, including the duration and severity of this outbreak as well as third-party actions taken to contain its spread and mitigate its public health effects. We do not yet know the full extent of the potential impact to our business or the global economy as a whole and could be significant. In addition, we cannot predict the impact that COVID-19 will have on our customers, suppliers, vendors, and other business partners, and each of their financial conditions; however, any material effect on these parties could adversely impact us.

Operational - The COVID-19 pandemic could cause material disruptions to our business and operations in the future as a result of, among other things, quarantines, cyber-attacks, worker absenteeism as a result of illness or other factors, social distancing measures and other travel, health-related, business or other restrictions. If a significant percentage of our workforce is unable to work, including because of illness or travel or government restrictions in connection with pandemics or disease outbreaks, our operations may be negatively affected. An extended period of remote work arrangements could strain our business continuity plans, introduce operational risk, including but not limited to cybersecurity risks, and impair our ability to manage our business.

For similar reasons, the COVID-19 pandemic may similarly adversely impact our suppliers and their manufacturers. Depending on the extent and duration of all of the above-described effects on our business and operations and the business and operations of our suppliers, our costs could increase, including our costs to address the health and safety of personnel, and our ability to obtain certain supplies or services.

National, state and local governments have responded to the COVID-19 pandemic in a variety of ways, including, without limitation, by declaring states of emergency, restricting people from gathering in groups or interacting within a certain physical distance (i.e., social distancing), and in certain cases, ordering businesses to close or limit operations or people to stay at home.

Although we provide critical infrastructure services and are permitted to continue to operate in each of our jurisdictions, including jurisdictions that have mandated the closure of certain businesses, there is no assurance that we will be allowed to continue full operations under future government orders or restrictions.

Any such workforce implications, supply chain disruptions, and / or limitations or closures may impact our ability to achieve our capital investment program and could have a material adverse impact on our ability to serve our customers and on our business, financial condition and results of operations.

The impact of COVID-19 may also exacerbate risks discussed below, any of which could have a material effect on us. This situation is changing rapidly and additional impacts may arise that we are not aware of currently.

Regulatory, Legislative and Legal Risks

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 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.

We provide service at rates established by several regulatory commissions. Rates are generally set through a process called a rate review (or rate case) in which the utility commission analyzes our costs incurred during a historical test year and decides whether they may be included in our rates. Rate reviews can be highly contested proceedings. There is no guarantee that the costs we seek to recover in future rates will be allowed. There is also typically a significant lag between the time we incur a cost and recover that cost in rates.

In addition to rate cases, our cost tracking mechanisms are a significant component of how we recover our costs. Trackers can also be highly contested dockets and, as with a rate case, there is no guarantee that the regulatory commission will approve our request to recover costs. Our PCCAM docket for the July 1, 2018 to June 30, 2019 time period includes replacement power costs procured during an intermittent outage at Colstrip Unit 4 in 2018. In addition, in May 2019, the statute changed removing the previously established "deadband" of +/- \$4.1 million from base costs and removing QF costs from the 90% / 10% sharing calculation. A hearing in this docket is scheduled for June 2020, and there can be no assurance that the MPSC will allow recovery of costs consistent with our filing, which could have a material adverse effect on our financial results.

Rate regulation is premised on providing an opportunity to earn a reasonable rate of return on invested capital. In a continued low interest rate environment there has been pressure pushing down return on equity. There also 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, 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. 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 methodologies. Thus, the rates we are allowed to charge may or may not match our costs at any given time. Adverse regulatory rulings could have an adverse impact on our results of operations and materially affect our ability to meet our financial obligations, including debt payments and the payment of dividends on our common stock.

In May 2019, we submitted a filing with the FERC related to 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.

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. 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.

We are subject to extensive and changing environmental laws and regulations, including legislative and regulatory responses to climate change, with which compliance may be difficult and costly.

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 public policy on climate change, 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 new 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 Affordable Clean Energy Rule (ACE). ACE repealed the 2015 Clean Power Plan (CPP) in regulating greenhouse gas (GHG) emissions from coal-fired plants. Under ACE, states must establish unit-specific standards. Although the United States has not adopted federal GHG legislation, 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 CO₂ 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.

Early closure of our owned and jointly owned electric generating facilities due to environmental risks, litigation or public policy changes could have a material adverse impact on our results of operations and liquidity.

While our Company-wide electric supply portfolio is over 58% carbon-free, it includes coal-fired resources and environmental advocacy groups, certain investors and other third parties oppose the operation of certain facilities, expressing concerns about the environmental and climate-related impacts from 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 GHG or other emissions or coal combustion residuals disposal and storage; activist shareholder proposals; and increased activism before our regulators. We cannot predict the effect that any such opposition may have on our ability to operate and recover the costs of our generating facilities. In addition, defense costs associated with litigation can be significant and an adverse outcome could require substantial capital expenditures and could possibly require payment of substantial penalties or damages. Such payments or expenditures could affect results of operations, financial condition or cash flows if such costs are not recovered through regulated rates.

Early closure of our generation facilities due to economic conditions, environmental regulations and / or litigation could result in regulatory impairments, increased cost of operations and inability to serve our customers in periods of peak demand. 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 some 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 January 2020, the owners of Units 1 and 2 closed those two units. 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 Units 3 and 4 currently share the operating costs pursuant to the terms of an operating agreement among them. Costs of facilities in common with all four units are shared among the owners of all four units. With the closure of Units 1 and 2, 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. We would expect to incorporate any reduction in revenue in our next general electric rate filing, resulting in lower revenue credits to certain customers.

In addition, the remaining depreciable life of our investment in Colstrip Unit 4 is through 2042. Our recovery of costs associated with the shut-down of the facility prior to the end of the depreciable life would be subject to MPSC approval. 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. Although one of those owners announced in October 2019 the intent to retire its share of Units 3 and 4 in 2027, under the Ownership and Operation Agreement to which each of the Colstrip Units 3 and 4 co-owners are a party, we believe that Unit 4 cannot be closed without each co-owner's consent.

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. The 500 kV 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.

Increased risks of regulatory penalties could negatively impact our business.

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.

Additionally, the Pipeline and Hazardous Materials Safety Administration, Occupational Safety and Health Administration and other federal agencies have penalty authority. In the event of serious incidents, these agencies have become more active in pursuing penalties. Some states have the authority to impose substantial penalties. If a serious reliability or safety incident did occur, it could have a material effect on our results of operations, financial condition or cash flows.

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 PCCAM 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. Finally, the requirement to procure power from these QF sources may impact our transmission system and require additional transmission facilities to be developed in order to integrate these resources, which also can impact overall customer bills.

Operational Risks

Our electric and natural gas 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 transmission and distribution and natural gas transportation and distribution operations are a variety of hazards and operating risks, such as breakdown or failure of equipment or processes, interruptions in fuel supply, labor disputes, operator error, and catastrophic events such as fires, electric contacts, leaks, explosions, floods and intentional acts of destruction. These risks could cause a loss of human life, facility shutdown or 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 power line 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.

For our electric generating facilities, 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 and potential litigation which may not be recovered from customers.

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.

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.

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. 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 the sharing component of the Montana PCCAM.

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.

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.

Liquidity and Financial Risks

Our plans for future expansion through the acquisition of assets, 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.

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.

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—Term Loan Agreement, dated as of April 3, 2020, among NorthWestern Corporation, as Borrower, the several lenders from time to time parties thereto and U.S. Bank National Association, as administrative agent \(incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated April 6, 2020, Commission File No. 1-10499\).](#)

[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—Inline 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—Inline XBRL Taxonomy Extension Schema Document

Exhibit 101.CAL—Inline XBRL Taxonomy Extension Calculation Linkbase Document

Exhibit 101.DEF—Inline XBRL Taxonomy Extension Definition Linkbase Document

Exhibit 101.LAB—Inline XBRL Taxonomy Label Linkbase Document

Exhibit 101.PRE—Inline XBRL Taxonomy Extension Presentation Linkbase Document

Exhibit 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.

Date: April 23, 2020

NorthWestern Corporation
By: /s/ BRIAN B. BIRD

Brian B. Bird

Chief Financial Officer

Duly Authorized Officer and Principal Financial Officer