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 June 30, 2018

OR

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

For the transition period from to

Commission File Number: 1-10499

NorthWestern Energy

NORTHWESTERN CORPORATION

(Exact name of registrant as specified in its charter)

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

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

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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted 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 and post 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 ☐ (Do not check if smaller reporting company) 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. Yes ☐ No ☐

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
50,316,536 shares outstanding at July 13, 2018

NORTHWESTERN CORPORATION

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

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

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

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

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

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

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

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

ITEM 1. FINANCIAL STATEMENTS

NORTHWESTERN CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(Unaudited)

(in thousands, except per share amounts)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	**2017**	**2018**	**2017**
Revenues				
Electric	$ 209,755	$ 233,866	$ 448,097	$ 500,105
Gas	52,062	49,993	155,222	151,066
Total Revenues	261,817	283,859	603,319	651,171
Operating Expenses				
Cost of sales	32,190	84,000	128,267	203,817
Operating, general and administrative	73,834	72,601	148,179	150,935
Property and other taxes	43,042	39,481	85,855	79,409
Depreciation and depletion	43,541	41,495	87,296	82,956
Total Operating Expenses	192,607	237,577	449,597	517,117
Operating Income	69,210	46,282	153,722	134,054
Interest Expense, net	(23,197)	(23,408)	(46,167)	(46,808)
Other Income (Expense), net	876	(464)	(253)	(1,592)
Income Before Income Taxes	46,889	22,410	107,302	85,654
Income Tax Expense	(3,102)	(580)	(5,016)	(7,257)
Net Income	$ 43,787	$ 21,830	$ 102,286	$ 78,397
Average Common Shares Outstanding	49,869	48,451	49,644	48,418
Basic Earnings per Average Common Share	$ 0.88	$ 0.45	$ 2.06	$ 1.62
Diluted Earnings per Average Common Share	$ 0.87	$ 0.44	$ 2.05	$ 1.61
Dividends Declared per Common Share	$ 0.55	$ 0.525	$ 1.10	$ 1.05

See Notes to Condensed Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)

(in thousands)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	**2017**	**2018**	**2017**
Net Income	$ 43,787	$ 21,830	$ 102,286	78,397
Other comprehensive income, net of tax:				
Foreign currency translation	86	(104)	181	(53)
Reclassification of net losses on derivative instruments	113	93	226	186
Total Other Comprehensive Income (Loss)	199	(11)	407	133
Comprehensive Income	$ 43,986	$ 21,819	$ 102,693	$ 78,530

See Notes to Condensed Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)
(in thousands, except share data)

	June 30, 2018	December 31, 2017
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 5,569	$ 8,473
Restricted cash	7,343	3,556
Accounts receivable, net	129,975	182,282
Inventories	46,698	52,432
Regulatory assets	27,551	37,669
Other	14,784	11,947
Total current assets	**231,920**	**296,359**
Property, plant, and equipment, net	4,417,662	4,358,265
Goodwill	357,586	357,586
Regulatory assets	375,962	354,316
Other noncurrent assets	55,844	54,391
Total Assets	**$ 5,438,974**	**$ 5,420,917**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current maturities of capital leases	2,212	$ 2,133
Short-term borrowings	—	319,556
Accounts payable	56,559	85,160
Accrued expenses	215,373	210,047
Regulatory liabilities	25,667	15,342
Total current liabilities	**299,811**	**632,238**
Long-term capital leases	21,107	22,213
Long-term debt	2,009,827	1,793,416
Deferred income taxes	365,840	340,729
Noncurrent regulatory liabilities	442,686	417,701
Other noncurrent liabilities	401,972	415,705
Total Liabilities	**3,541,243**	**3,622,002**
Commitments and Contingencies (Note 12)		
Shareholders' Equity:		
Common stock, par value $0.01; authorized 200,000,000 shares; issued and outstanding 53,889,410 and 50,315,374 shares, respectively; Preferred stock, par value $0.01; authorized 50,000,000 shares; none issued	539	530
Treasury stock at cost	(95,768)	(96,376)
Paid-in capital	1,494,940	1,445,181
Retained earnings	508,528	458,352
Accumulated other comprehensive loss	(10,508)	(8,772)
Total Shareholders' Equity	**1,897,731**	**1,798,915**
Total Liabilities and Shareholders' Equity	**$ 5,438,974**	**$ 5,420,917**

See Notes to Condensed Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)
(in thousands)

	Six Months Ended June 30,	
	2018	**2017**
OPERATING ACTIVITIES:		
Net income	$ 102,286	$ 78,397
Items not affecting cash:		
Depreciation and depletion	87,296	82,956
Amortization of debt issue costs, discount and deferred hedge gain	2,333	2,392
Stock-based compensation costs	3,738	3,826
Equity portion of allowance for funds used during construction	(1,531)	(2,298)
Loss (gain) on disposition of assets	11	(401)
Deferred income taxes	5,019	6,320
Changes in current assets and liabilities:		
Accounts receivable	52,307	35,631
Inventories	5,734	(1,393)
Other current assets	(2,801)	(3,241)
Accounts payable	(23,849)	(19,788)
Accrued expenses	5,266	(4,853)
Regulatory assets	10,118	14,143
Regulatory liabilities	10,325	(9,691)
Other noncurrent assets	(3,908)	(6,781)
Other noncurrent liabilities	(5,217)	3,767
Cash Provided by Operating Activities	**247,127**	**178,986**
INVESTING ACTIVITIES:		
Property, plant, and equipment additions	(116,456)	(119,123)
Acquisitions	(18,517)	—
Proceeds from sale of assets	—	379
Cash Used in Investing Activities	**(134,973)**	**(118,744)**
FINANCING ACTIVITIES:		
Treasury stock activity	1,773	411
Proceeds from issuance of common stock, net	44,865	—
Dividends on common stock	(54,253)	(50,396)
Line of credit borrowings	1,129,000	—
Line of credit repayments	(913,000)	—
(Repayments) issuances of short-term borrowings, net	(319,556)	2,847
Financing costs	(100)	(142)
Cash Used in Financing Activities	**(111,271)**	**(47,280)**
Increase in Cash, Cash Equivalents, and Restricted Cash	883	12,962
Cash, Cash Equivalents, and Restricted Cash, beginning of period	12,029	9,505
Cash, Cash Equivalents, and Restricted Cash, end of period	**$ 12,912**	**$ 22,467**
Supplemental Cash Flow Information:		
Cash paid during the period for:		
Income taxes	$ 55	$ 61
Interest	38,890	40,280
Significant non-cash transactions:		
Capital expenditures included in accounts payable	11,266	9,776

See Notes to Condensed Consolidated Financial Statements

NORTHWESTERN CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(Unaudited)
(in thousands, except per share data)

	Number of Common Shares	Number of Treasury Shares	Common Stock	Paid in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Total Shareholders' Equity
Balance at December 31, 2016	**51,958**	**3,626**	**$ 520**	**$1,384,271**	**$ (95,769)**	**$396,919**	**$ (9,714)**	**$ 1,676,227**
Net income	—	—	—	—	—	78,397	—	78,397
Foreign currency translation adjustment	—	—	—	—	—	—	(53)	(53)
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	186	186
Stock-based compensation	133	(6)	1	5,155	(920)	—	—	4,236
Dividends on common stock ($1.05 per share)	—	—	—	—	—	(50,396)	—	(50,396)
Balance at June 30, 2017	**52,091**	**3,620**	**$ 521**	**$1,389,426**	**$ (96,689)**	**$424,920**	**$ (9,581)**	**$ 1,708,597**
Balance at December 31, 2017	**52,981**	**3,609**	**$ 530**	**$1,445,181**	**$ (96,376)**	**$458,352**	**$ (8,772)**	**$ 1,798,915**
Net income	—	—	—	—	—	102,286	—	102,286
Foreign currency translation adjustment	—	—	—	—	—	—	181	181
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	226	226
Reclassification of certain tax effects from AOCL	—	—	—	—	—	2,143	(2,143)	—
Stock-based compensation	72	(35)	—	4,903	608	—	—	5,511
Issuance of shares	836	—	9	44,856	—	—	—	44,865
Dividends on common stock ($1.10 per share)	—	—	—	—	—	(54,253)	—	(54,253)
Balance at June 30, 2018	**53,889**	**3,574**	**$ 539**	**$1,494,940**	**$ (95,768)**	**$508,528**	**$ (10,508)**	**$ 1,897,731**

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 718,300 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 June 30, 2018, 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 unaudited 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, 2017.

Variable Interest Entities

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

Certain long-term purchase power and tolling contracts may be considered variable interests. We have various long-term purchase power contracts with other utilities and certain qualifying co-generation facilities and qualifying small power production facilities (QF). We identified one QF contract that may constitute a VIE. We entered into a 40-year power purchase contract in 1984 with this 35 megawatt (MW) coal-fired QF to purchase substantially all of the facility's capacity and electrical output over a substantial portion of its estimated useful life. We absorb a portion of the facility's variability through annual changes to the price we pay per megawatt hour (MWH). After making exhaustive efforts, we have been unable to obtain the information from the facility necessary to determine whether the facility is a VIE or whether we are the primary beneficiary of the facility. The contract with the facility contains no provision which legally obligates the facility to release this information. We have accounted for this QF contract as an executory contract. Based on the current contract terms with this QF, our estimated gross contractual payments aggregate approximately $183.3 million through 2024.

Accounting Standards Adopted

Revenue Recognition - In May 2014, the Financial Accounting Standards Board (FASB) issued accounting guidance on the recognition of revenue from contracts with customers, which supersedes nearly all existing revenue recognition guidance under GAAP. Under the new standard, entities will recognize revenue to depict the transfer of goods and services to customers in amounts that reflect the payment to which the entity expects to be entitled in exchange for those goods or services. The guidance also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows from an entity's contracts with customers.

We adopted this standard as of January 1, 2018, as required, and used the modified retrospective method of adoption, with no material impact on our financial statements or internal controls. We have also elected to utilize certain practical expedients, which allow us to apply the standard to open contracts at the date of adoption and to reflect the aggregate effect of all modifications when identifying performance obligations and allocating the transaction price for contracts modified before the effective date. We completed a comprehensive review of contracts and their associated terms and conditions. Based on this analysis, we did not have a cumulative-effect adjustment to retained earnings at January 1, 2018. See Note 2 - Revenue from Contracts with Customers, for additional disclosures including revenue recognition policies and our disaggregated revenue by segment for each geographical region.

Retirement Benefits - On January 1, 2018, we adopted Accounting Standards Update (ASU) 2017-07, Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, as issued by the FASB. Under this ASU, companies are required to disaggregate the current service cost component from the other components of net periodic benefit cost and present it with other current compensation costs for related employees in the income statement and present the other components elsewhere in the income statement and outside of income from operations. In addition, only the service cost component of net periodic benefit cost is eligible for capitalization.

ASU 2017-07 was applied on a modified retrospective basis for the presentation of the other components of net periodic benefit cost in the Condensed Consolidated Statements of Income. Using the allowed practical expedient, we applied the amounts disclosed in the “Employee Benefit Plans” note to the 2017 Consolidated Financial Statements for the restatement of comparative information. The impact of the adoption of this guidance resulted in the reclassification of the other components of net benefit cost from operating, general, and administrative expense to other expense, net in the Condensed Consolidated Statements of Income. The following table summarizes the adjustments made to conform prior period classifications to the new guidance (in thousands):

	Three Months Ended June 30, 2017		
	As Reported	Effect of Accounting Change	As Adjusted
Operating, general and administrative	$ 75,188	$ (2,587)	$ 72,601
Other Income (Expense), net	2,123	(2,587)	(464)

	Six Months Ended June 30, 2017		
	As Reported	Effect of Accounting Change	As Adjusted
Operating, general and administrative	$ 156,150	$ (5,215)	$ 150,935
Other Income (Expense), net	3,623	(5,215)	(1,592)

	As Reported	Effect of Accounting Change	As Adjusted
	Year Ended December 31, 2017		
Operating, general and administrative	$ 305,137	$ (10,334)	$ 294,803
Other Income (Expense), net	6,919	(10,334)	(3,415)
	Year Ended December 31, 2016		
Operating, general and administrative	$ 302,893	$ (9,030)	$ 293,863
Other Income (Expense), net	5,548	(9,030)	(3,482)
	Year Ended December 31, 2015		
Operating, general and administrative	$ 297,475	$ (6,757)	$ 290,718
Other Income (Expense), net	7,583	(6,757)	826

ASU 2017-07 was applied prospectively for the capitalization of related costs in assets and did not have a material impact. As a result of application of accounting principles for rate regulated entities, a similar amount of pension cost, including non-service components, will be recognized consistent with the current ratemaking treatment.

Statement of Cash Flows - In August 2016, the FASB issued guidance that addresses eight classification issues related to the presentation of cash receipts and cash payments in the statement of cash flows. We adopted this standard as of January 1, 2018, with no material impact to our Condensed Consolidated Statements of Cash Flows, and although the guidance requires retrospective treatment, we did not have any cash receipts or payments during the prior year that needed to be reclassified.

In November 2016, the FASB issued guidance that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Amounts generally described as restricted cash should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. We adopted this standard as of January 1, 2018 with retrospective application. For the six months ended June 30, 2017, this change resulted in a $4.4 million and $5.6 million increase in cash, cash equivalents and restricted cash at the beginning and end of the period on our Condensed Consolidated Statements of Cash Flows, respectively. In addition, removing the change in restricted cash from operating activities in the Condensed Consolidated Statements of Cash Flows resulted in an increase of $1.2 million in our cash provided by operating activities for the six months ended June 30, 2017.

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):

	June 30, 2018	December 31, 2017	June 30, 2017	December 31, 2016	December 31, 2015
Cash and cash equivalents	$ 5,569	$ 8,473	$ 16,859	$ 5,079	$ 11,980
Restricted cash	7,343	3,556	5,608	4,426	6,634
Total cash, cash equivalents, and restricted cash shown in the Condensed Consolidated Statements of Cash Flows	$ 12,912	$ 12,029	$ 22,467	$ 9,505	$ 18,614

Restricted cash consists primarily of funds held in trust accounts to satisfy the requirements of certain stipulation agreements and insurance reserve requirements.

Stranded Tax Effects in Accumulated Other Comprehensive Loss - In February 2018, the FASB issued guidance to allow a one-time reclassification from accumulated other comprehensive loss (AOCL) to retained earnings for stranded tax effects resulting from the new tax reform legislation. The amount of the reclassification is calculated on the basis of the difference between the historical and newly enacted tax rates for deferred tax liabilities and assets related to items within AOCL.

This amendment is effective for fiscal years beginning after December 15, 2018, including interim periods within those years. Early adoption is permitted, including adoption in any interim reporting period for which financial statements have not yet been issued. We early adopted this guidance during the first quarter of 2018, through a one-time reclassification of $2.1 million of stranded tax effects from AOCL to retained earnings. Adoption of this guidance did not have a material impact on our condensed consolidated financial position, results of operations or cash flows.

Accounting Standards Issued

Leases - In February 2016, the FASB issued revised guidance on accounting for leases. The new standard requires a lessee to recognize in the balance sheet a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term for all leases with terms longer than 12 months. Leases with a term of 12 months or less will be accounted for similar to existing guidance for operating leases. Recognition, measurement and presentation of expenses will depend on classification as a finance or operating lease. The new guidance will be effective for us for interim and annual periods beginning January 1, 2019 and early adoption is permitted. A modified retrospective transition approach is required for lessees for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. An additional transition approach allows an entity to not assess on transition whether any expired or existing land easements are, or contain, leases that were not previously accounted for as leases. In addition, our easements are entered into in perpetuity and do not meet the definition of a lease in accordance with this guidance. We are currently evaluating the impact of adoption of this guidance. We do not have a significant amount of capital or operating leases. Therefore, based on our analysis to this point we do not expect this guidance to have a significant impact on our Financial Statements and disclosures other than an expected increase in assets and liabilities.

(2) Revenue from Contracts with Customers

Accounting Policy

Our revenues are primarily from tariff based sales. We provide gas and/or electricity to customers under these tariffs without a defined contractual term (at-will). As the revenue from these arrangements is equivalent to the electricity or gas supplied and billed in that period (including estimated billings), there will not be a shift in the timing or pattern of revenue recognition for such sales. We have also completed the evaluation of our other revenue streams, including those tied to longer term contractual commitments. These revenue streams have performance obligations that are satisfied at a point in time, and will also not have a shift in the timing or pattern of revenue recognition.

Customers are billed monthly on a cycle basis. To match revenues with associated expenses, we accrue unbilled revenues for electric and natural gas services delivered to customers, but not yet billed at month-end.

Nature of Goods and Services

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

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

Natural Gas Segment - Our regulated natural gas utility business primarily provides production, storage, transmission and distribution services to our customers in our Montana, South Dakota, and Nebraska jurisdictions. We recognize revenue when natural gas is delivered to the customer. Payments on our tariff based sales are generally due in 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					
	June 30, 2018			June 30, 2017		
	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Montana	$ 59.5	$ 17.6	$ 77.1	$ 59.7	$ 16.5	$ 76.2
South Dakota	14.4	5.6	20.0	12.9	4.3	17.2
Nebraska	—	5.0	5.0	—	4.1	4.1
Residential	**73.9**	**28.2**	**102.1**	**72.6**	**24.9**	**97.5**
Montana	79.6	8.8	88.4	83.0	8.2	91.2
South Dakota	22.3	3.6	25.9	21.4	2.8	24.2
Nebraska	—	2.4	2.4	—	2.1	2.1
Commercial	**101.9**	**14.8**	**116.7**	**104.4**	**13.1**	**117.5**
Industrial	10.7	0.2	10.9	10.1	0.2	10.3
Lighting, Governmental, and Irrigation	7.1	0.2	7.3	8.9	0.1	9.0
Total Customer Revenues	**193.6**	**43.4**	**237.0**	**196.0**	**38.3**	**234.3**
Other Tariff and Contract Based Revenues	17.8	10.6	28.4	33.8	9.7	43.5
Total Revenue from Contracts with Customers	**211.4**	**54.0**	**265.4**	**229.8**	**48.0**	**277.8**
Regulatory amortization	(1.7)	(1.9)	(3.6)	4.1	2.0	6.1
Total Revenues	**$ 209.7**	**$ 52.1**	**$ 261.8**	**$ 233.9**	**$ 50.0**	**$ 283.9**

	Six Months Ended					
	June 30, 2018			June 30, 2017		
	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Montana	$ 146.7	$ 58.5	$ 205.2	$ 150.5	$ 60.3	$ 210.8
South Dakota	33.1	17.0	50.1	30.2	15.1	45.3
Nebraska	—	16.4	16.4	—	13.1	13.1
Residential	**179.8**	**91.9**	**271.7**	**180.7**	**88.5**	**269.2**
Montana	163.3	29.4	192.7	171.1	30.1	201.2
South Dakota	46.3	11.5	57.8	43.8	10.2	54.0
Nebraska	—	8.5	8.5	—	7.0	7.0
Commercial	**209.6**	**49.4**	**259.0**	**214.9**	**47.3**	**262.2**
Industrial	21.5	0.7	22.2	21.0	0.7	21.7
Lighting, Governmental, and Irrigation	12.1	0.7	12.8	14.1	0.6	14.7
Total Customer Revenues	**423.0**	**142.7**	**565.7**	**430.7**	**137.1**	**567.8**
Other Tariff and Contract Based Revenues	35.6	20.9	56.5	71.2	20.8	92.0
Total Revenue from Contracts with Customers	**458.6**	**163.6**	**622.2**	**501.9**	**157.9**	**659.8**
Regulatory amortization	(10.5)	(8.4)	(18.9)	(1.8)	(6.8)	(8.6)
Total Revenues	**$ 448.1**	**$ 155.2**	**$ 603.3**	**$ 500.1**	**$ 151.1**	**$ 651.2**

(3) Acquisition

Montana Wind Generation

In June 2018, we completed the purchase of the 9.7 MW Two Dot wind project near Two Dot, Montana for approximately $18.5 million. The Two Dot purchase price was allocated based on the estimated fair values of the assets acquired and liabilities assumed at the date of the acquisition as follows (in thousands):

Purchase Price Allocation		
Assets Acquired		
Property Plant and Equipment, net	$	18,542
Current Assets		35
Total Assets Acquired		18,577
Liabilities Assumed		
Accrued Expenses		60
Total Liabilities Assumed		60
Total Purchase Price	$	18,517

(4) Regulatory Matters

Tax Cuts and Jobs Act

In December 2017, H.R.1 (the Tax Cuts and Jobs Act) was signed into law, which enacts significant changes to U.S. tax and related laws. The primary impact to us is a reduction of the federal corporate income tax rate from 35% to 21% effective January 1, 2018. Our Montana and South Dakota Tax Cuts and Jobs Act filings are discussed below. Dockets have also been opened in our Federal Energy Regulatory Commission (FERC) and Nebraska jurisdictions, where we proposed using reduced revenue requirements from the impacts of the Tax Cuts and Jobs Act to defer planned future rate filings in both jurisdictions. In each of our jurisdictions, we expect the Tax Cuts and Jobs Act related credits to continue and be subject to true-up until base rates are reset in a general rate case filing or agreement is reached with our state regulatory commissions as to how the impact of the Tax Cuts and Job Act will be resolved.

As of June 30, 2018, we have deferred revenue of approximately $13.5 million associated with the impacts of the Tax Cuts and Jobs Act. For purposes of the filings discussed below, we calculated the customer benefit using two alternate methods based on current and historic test periods. The revenue deferral is based upon our 2018 estimated impact of Tax Cuts and Jobs Act of approximately $18 million to $23 million and is offset by a corresponding reduction in income tax expense. Application of the historic method would result in customer refunds that exceed the reduction in our 2018 taxes, which would be an additional reduction in pretax earnings and cash flows ranging from approximately $5 million to $10 million.

Montana - In March 2018, we submitted a filing to the Montana Public Service Commission (MPSC) calculating the estimated benefit of the Tax Cuts and Jobs Act related savings to customers using two alternative methods. The first method was calculated based on the expected income tax expense reduction in 2018, with no impact to net income. The second method was calculated by revising the electric and natural gas revenue requirements in the last applicable test years. For our electric customers, we proposed to use 50% of the benefit as a direct refund to customers, and to use the other 50% to remove trees outside our electric transmission and distribution lines rights of way, which pose risks to our system including disruption of service, property damage, and / or forest fires. We have begun work to remove trees outside our right of way, and as of June 30, 2018, have deferred $0.3 million of costs, which is recorded in the Condensed Consolidated Balance Sheets to reflect the impacts of the Tax Cuts and Jobs Act, subject to MPSC approval. For our natural gas customers, we proposed to use the benefit as a direct refund to customers.

South Dakota - In April 2018, we submitted a filing with the South Dakota Public Utilities Commission (SDPUC) calculating the estimated benefit of the Tax Cuts and Jobs Act related savings to customers based on the expected income tax expense reduction in 2018, with no impact to net income. We also presented a calculation revising the electric and natural gas revenue requirements in the last applicable test years. We proposed to either refund the benefit to customers, or to hold this amount in a regulatory liability to provide rate moderation in our next electric and natural gas rate cases, at the SDPUC's option. Settlement negotiations are currently ongoing. The SDPUC has not established a procedural schedule in this docket.

Montana QF Tariff Filing

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. In May 2016, we filed an application for approval of a revised tariff for standard rates for small QFs (3 MW or less). In November 2017, the MPSC issued an order (QF Order) revising the QF tariff to establish a maximum contract length of 15 years and substantially lowering the rate for future QF contracts. In the QF Order, the MPSC also upheld an initial decision to apply the contract term to our future owned and contracted electric supply resources. We, as well as the QFs, sought judicial review of the QF Order. The matter is now pending before the Montana District Court. The Court is scheduled to hear oral arguments on September 7, 2018.

As a result of the QF Order, we terminated our competitive solicitation process for 20-year resources to determine the lowest-cost / least-risk approach for addressing our intermittent capacity and reserve margin needs in Montana. We continue to evaluate the impact of the QF Order, as we have significant generation capacity deficits and negative reserve margins, and our 2015 resource plan identified price and reliability risks to our customers if we rely solely upon market purchases to address these capacity needs. In addition to our responsibility to meet peak demand, national transmission-related reliability standards effective July 2016 require us to have even greater dispatchable generation capacity available and be capable of increasing or decreasing output to address the irregular nature of intermittent generation such as wind or solar. We expect to file our next electric supply resource procurement plan in December 2018.

Cost Recovery Mechanisms

Montana House Bill 193 / Electric Tracker - In April 2017, the Montana legislature passed House Bill 193 (HB 193), amending the statute that provided for mandatory recovery of our prudently incurred electric supply costs effective July 1, 2017. The revised statute gives the MPSC discretion whether to approve an electric supply cost adjustment mechanism. The MPSC initiated a process to develop a replacement electric supply cost adjustment mechanism, and in response, in July 2017, we filed a proposed electric Power Cost and Credit Adjustment Mechanism (PCCAM). In December 2017, after the intervenors filed testimony, the MPSC issued a Notice of Additional Issues stating that the range of options proposed by the parties was not sufficient and directing parties to consider alternatives incorporating risk-sharing features of other utilities in the region.

We filed testimony in February 2018, responsive to both the intervenors' testimony and the MPSC's Notice of Additional Issues addressing alternative risk-sharing mechanisms. Intervenors filed testimony on the Notice of Additional Issues in March 2018. The MPSC held a hearing during the second quarter of 2018, and we expect a decision in the matter no later than the fourth quarter of 2018. If the MPSC approves a new mechanism, the MPSC may apply the mechanism to variable costs on a retroactive basis to the effective date of HB 193 (July 1, 2017).

Montana Electric Tracker Open Dockets - 2015/2016 - 2016/2017 - 2017/2018 (2015-2018 Tracker Filings) - Under the previous statutory tracker mechanism, each year we submitted an electric tracker filing for recovery of supply costs for the 12-month period ended June 30 and for the projected supply costs for the next 12-month period, which were subject to a prudency review. We continue to submit annual filings, pursuant to our tariff, until the MPSC approves a new cost recovery mechanism for electricity supply costs. The MPSC has issued three orders approving interim rates for the 2015-2018 Tracker Filings, but has not established a schedule for adjudication of these filings.

Montana Electric Tracker Litigation - 2013/2014 - In 2016, the MPSC issued an order which, in total, resulted in a $12.4 million disallowance of costs, including interest. The order included a disallowance of replacement power costs from a 2013 outage at Colstrip Unit 4. In September 2016, we appealed that order to the Montana District Court, arguing that the order was arbitrary and capricious and violated Montana law. We expect a decision on this appeal within the next nine months.

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 effective January 1st of each year. In January 2018, the MPSC issued an order in our 2017 filing applying an alternate allocation methodology both prospectively and retroactively, which reduces our annual recovery of these taxes by approximately $1.7 million. The change in methodology results in a lower property tax allocation to our Montana electric retail customers and a higher property tax allocation to FERC transmission customers (we do not have a property tax tracker for FERC jurisdictional purposes). We sought reconsideration of the retroactive application of this change in methodology. On June 18, 2018, the MPSC issued an order applying the change on a prospective basis only, resulting in a $1.7 million adjustment to reflect the increase in recovery of Montana property taxes for 2017 in the three months ended June 30, 2018, which is reflected in the Condensed Consolidated Statements of Income.

Dave Gates Generating Station at Mill Creek (DGGS)

In 2012 a FERC Administrative Law Judge (ALJ) issued a decision regarding cost allocation at DGGS and concluded that only a portion of the costs should be allocated to FERC jurisdictional customers. In 2016, the FERC denied our request for rehearing of the ALJ decision and ordered us to make refunds, which we did in June 2016. In March 2018, the United States Circuit Court of Appeals for the District of Columbia Circuit denied our petition for review of the FERC's order and the matter is now final.

(5) Income Taxes

The primary impact of the Tax Cuts and Jobs Act is a reduction of the federal corporate income tax rate from 35% to 21% effective January 1, 2018. 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. We revalued our deferred tax assets and liabilities as of December 31, 2017, which reflected our estimate of the impact of the Tax Cuts and Jobs Act. We will continue to evaluate subsequent regulations, clarifications and interpretations with the assumptions made, which could materially change our estimate.

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

	Three Months Ended June 30,			
	2018		2017	
Income Before Income Taxes	$ 46,889		$ 22,410	
Income tax calculated at federal statutory rate	9,846	21.0%	7,844	35.0%
Permanent or flow through adjustments:				
State income, net of federal provisions	801	1.7	(492)	(2.2)
Flow-through repairs deductions	(4,095)	(8.7)	(4,753)	(21.2)
Production tax credits	(2,559)	(5.5)	(1,459)	(6.5)
Plant and depreciation of flow through items	(571)	(1.2)	(686)	(3.1)
Other, net	(320)	(0.7)	126	0.6
	(6,744)	(14.4)	(7,264)	(32.4)
Income Tax Expense	$ 3,102	6.6%	$ 580	2.6%

	Six Months Ended June 30,			
	2018		2017	
Income Before Income Taxes	$ 107,302		$ 85,654	
Income tax calculated at 35% federal statutory rate	22,533	21.0%	29,979	35.0%
Permanent or flow through adjustments:				
State income, net of federal provisions	1,533	1.5	(1,326)	(1.5)
Flow-through repairs deductions	(10,681)	(10.0)	(13,550)	(15.8)
Production tax credits	(6,447)	(6.0)	(5,290)	(6.2)
Plant and depreciation of flow through items	(1,487)	(1.4)	(2,126)	(2.5)
Share-based compensation	275	0.3	(399)	(0.5)
Other, net	(710)	(0.7)	(31)	—
	(17,517)	(16.3)	(22,722)	(26.5)
Income Tax Expense	$ 5,016	4.7%	$ 7,257	8.5%

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 $57.1 million as of June 30, 2018, including approximately $47.7 million that, if recognized, would impact our effective tax rate. It is reasonably possible that our unrecognized tax benefits may decrease by up to $20 million in the next 12 months due to the expiration of statute of limitation.

Our policy is to recognize interest and penalties related to uncertain tax positions in income tax expense. During the six months ended June 30, 2018 and 2017, we recognized $0.6 million and $0.3 million, respectively, of expense for interest and penalties in the Condensed Consolidated Statements of Income. As of June 30, 2018 and December 31, 2017, we had $2.1 million and $1.5 million, respectively, of interest accrued in the Condensed Consolidated Balance Sheets.

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

(6) Goodwill

We completed our annual goodwill impairment test as of April 1, 2018, and no impairment was identified. We calculate the fair value of our reporting units by considering various factors, including valuation studies based primarily on a discounted cash flow analysis, with published industry valuations and market data as supporting information. Key assumptions in the determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate expected long-term growth rates in our service territory, regulatory stability, and commodity prices (where appropriate), as well as other factors that affect our revenue, expense and capital expenditure projections.

There were no changes in our goodwill during the six months ended June 30, 2018. Goodwill by segment is as follows for both June 30, 2018 and December 31, 2017 (in thousands):

Electric	$ 243,558
Natural gas	114,028
Total	$ 357,586

(7) Comprehensive Income

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

	Three Months Ended					
	June 30, 2018			June 30, 2017		
	Before-Tax Amount	Tax Expense	Net-of-Tax Amount	Before-Tax Amount	Tax Expense	Net-of-Tax Amount
Foreign currency translation adjustment	$ 86	$ —	$ 86	$ (104)	$ —	$ (104)
Reclassification of net losses on derivative instruments	154	(41)	113	153	(60)	93
Other comprehensive income (loss)	$ 240	$ (41)	$ 199	$ 49	$ (60)	$ (11)

	Six Months Ended					
	June 30, 2018			June 30, 2017		
	Before-Tax Amount	Tax Expense	Net-of-Tax Amount	Before-Tax Amount	Tax Expense	Net-of-Tax Amount
Foreign currency translation adjustment	$ 181	$ —	$ 181	$ (53)	$ —	$ (53)
Reclassification of net losses on derivative instruments	307	(81)	226	306	(120)	186
Other comprehensive income	$ 488	$ (81)	$ 407	$ 253	$ (120)	$ 133

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

	June 30, 2018	December 31, 2017
Foreign currency translation	$ 1,359	$ 1,178
Derivative instruments designated as cash flow hedges	(9,755)	(9,981)
Reclassification of certain tax effects from AOCL	(2,143)	—
Postretirement medical plans	31	31
Accumulated other comprehensive loss	$ (10,508)	$ (8,772)

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

		Three Months Ended June 30, 2018			
	Affected Line Item in the Condensed Consolidated Statements of Income	Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Pension and Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (12,018)	$ 38	$ 1,273	$ (10,707)
Other comprehensive income before reclassifications		—	—	86	86
Amounts reclassified from AOCL	Interest Expense	113	—	—	113
Net current-period other comprehensive income		113	—	86	199
Ending balance		$ (11,905)	$ 38	$ 1,359	$ (10,508)

	Affected Line Item in the Condensed Consolidated Statements of Income	Three Months Ended June 30, 2017 Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Pension and Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (10,259)	$ (742)	$ 1,431	(9,570)
Other comprehensive loss before reclassifications		—	—	(104)	(104)
Amounts reclassified from AOCL	Interest Expense	93	—	—	93
Net current-period other comprehensive income (loss)		93	—	(104)	(11)
Ending balance		$ (10,166)	$ (742)	$ 1,327	$ (9,581)

	Affected Line Item in the Condensed Consolidated Statements of Income	Six Months Ended June 30, 2018 Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Pension and Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (9,981)	$ 31	$ 1,178	$ (8,772)
Other comprehensive income before reclassifications		—	—	181	181
Amounts reclassified from AOCL	Interest Expense	226	—	—	226
Net current-period other comprehensive income		226	—	181	407
Reclassification of certain tax effects from AOCL		(2,150)	7	—	(2,143)
Ending balance		$ (11,905)	$ 38	$ 1,359	$ (10,508)

	Affected Line Item in the Condensed Consolidated Statements of Income	Six Months Ended June 30, 2017 Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Pension and Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (10,352)	$ (742)	$ 1,380	$ (9,714)
Other comprehensive loss before reclassifications		—	—	(53)	(53)
Amounts reclassified from AOCL	Interest Expense	186	—	—	186
Net current-period other comprehensive income (loss)		186	—	(53)	133
Ending balance		$ (10,166)	$ (742)	$ 1,327	$ (9,581)

(8) Financing Activities

In September 2017, we entered into an Equity Distribution Agreement with Merrill Lynch, Pierce, Fenner & Smith Incorporated and J. P. Morgan Securities LLC, collectively the sales agents, pursuant to which we offered and sold shares of our common stock from time to time, having an aggregate gross sales price of up to $100 million. During the three months ended June 30, 2018, we issued 835,765 shares of our common stock at an average price of $54.45, for net proceeds of $44.9 million, which is net of sales commissions and other fees paid of approximately $0.6 million. These issuances concluded this program. Since inception of the program, we sold 1,724,703 shares of our common stock at an average price of $57.98 per share. Net proceeds received were approximately $98.6 million, which are net of sales commissions and other fees paid of approximately $1.4 million.

(9) 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.

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 June 30, 2018	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 209,755	$ 52,062	$ —	$ —	$ 261,817
Cost of sales	19,613	12,577	—	—	32,190
Gross margin	190,142	39,485	—	—	229,627
Operating, general and administrative	52,894	19,650	1,290	—	73,834
Property and other taxes	33,880	9,160	2	—	43,042
Depreciation and depletion	36,139	7,394	8	—	43,541
Operating income	67,229	3,281	(1,300)	—	69,210
Interest expense	(20,318)	(1,161)	(1,718)	—	(23,197)
Other (expense) income	(52)	(191)	1,119	—	876
Income tax (expense) benefit	(2,649)	492	(945)	—	(3,102)
Net income (loss)	$ 44,210	$ 2,421	$ (2,844)	$ —	$ 43,787
Total assets	$ 4,351,359	$ 1,072,173	$ 15,442	$ —	$ 5,438,974
Capital expenditures	$ 52,844	$ 11,607	$ —	$ —	$ 64,451

Three Months Ended June 30, 2017	**Electric**	**Gas**	**Other**	**Eliminations**	**Total**
Operating revenues	$ 233,866	$ 49,993	$ —	$ —	$ 283,859
Cost of sales	70,146	13,854	—	—	84,000
Gross margin	163,720	36,139	—	—	199,859
Operating, general and administrative (1)	52,215	19,490	896	—	72,601
Property and other taxes	30,909	8,569	3	—	39,481
Depreciation and depletion	34,105	7,382	8	—	41,495
Operating income (loss)	46,491	698	(907)	—	46,282
Interest expense	(21,064)	(1,500)	(844)	—	(23,408)
Other (expense) income (1)	(954)	(227)	717	—	(464)
Income tax (expense) benefit	(523)	817	(874)	—	(580)
Net income (loss)	$ 23,950	$ (212)	$ (1,908)	$ —	$ 21,830
Total assets	$ 4,439,694	$ 1,114,426	$ 2,812	$ —	$ 5,556,932
Capital expenditures	$ 55,995	$ 11,609	$ —	$ —	$ 67,604

(1) We adopted ASU 2017-07 on January 1, 2018. As a result, we recorded the non-service cost component of net periodic benefit cost within other expense, net. We adopted this standard retrospectively and $1.9 million and $0.7 million, respectively, were reclassified from electric and gas operating, general and administrative expenses to other expense, net for the three months ended June 30, 2017, to conform to current period presentation.

Six Months Ended June 30, 2018	**Electric**	**Gas**	**Other**	**Eliminations**	**Total**
Operating revenues	$ 448,097	$ 155,222	$ —	$ —	$ 603,319
Cost of sales	76,886	51,381	—	—	128,267
Gross margin	371,211	103,841	—	—	475,052
Operating, general and administrative	107,542	40,869	(232)	—	148,179
Property and other taxes	67,373	18,478	4	—	85,855
Depreciation and depletion	72,292	14,988	16	—	87,296
Operating income	124,004	29,506	212	—	153,722
Interest expense	(39,838)	(3,015)	(3,314)	—	(46,167)
Other income (loss)	438	(83)	(608)	—	(253)
Income tax expense	(3,147)	(1,734)	(135)	—	(5,016)
Net income (loss)	$ 81,457	$ 24,674	$ (3,845)	$ —	$ 102,286
Total assets	$ 4,351,359	$ 1,072,173	$ 15,442	$ —	$ 5,438,974
Capital expenditures	$ 95,742	$ 20,714	$ —	$ —	$ 116,456

Six Months Ended June 30, 2017	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 500,105	$ 151,066	$ —	$ —	$ 651,171
Cost of sales	155,531	48,286	—	—	203,817
Gross margin	344,574	102,780	—	—	447,354
Operating, general and administrative (1)	108,935	40,390	1,610	—	150,935
Property and other taxes	62,070	17,333	6	—	79,409
Depreciation and depletion	68,175	14,765	16	—	82,956
Operating income (loss)	105,394	30,292	(1,632)	—	134,054
Interest expense	(42,101)	(3,046)	(1,661)	—	(46,808)
Other (expense) income (1)	(2,147)	(728)	1,283	—	(1,592)
Income tax (expense) benefit	(3,410)	(6,134)	2,287	—	(7,257)
Net income	$ 57,736	$ 20,384	$ 277	$ —	$ 78,397
Total assets	$ 4,439,694	$ 1,114,426	$ 2,812	$ —	$ 5,556,932
Capital expenditures	$ 97,036	$ 22,087	$ —	$ —	$ 119,123

(1) We adopted ASU 2017-07 on January 1, 2018. As a result, we recorded the non-service cost component of net periodic benefit cost within other expense, net. We adopted this standard retrospectively and $3.8 million and $1.4 million, respectively, were reclassified from electric and gas operating, general and administrative expenses to other expense, net for the six months ended June 30, 2017, to conform to current period presentation.

(10) Earnings Per Share

Basic earnings per share is computed by dividing net income by the weighted average number of common shares outstanding for the period. Diluted earnings per share reflects the potential dilution of common stock equivalent shares that could occur if all 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 performance share awards. Average shares used in computing the basic and diluted earnings per share are as follows:

	Three Months Ended	
	June 30, 2018	June 30, 2017
Basic computation	49,869,176	48,450,639
Dilutive effect of:		
Performance share awards (1)	175,369	130,772
Diluted computation	50,044,545	48,581,411

	Six Months Ended	
	June 30, 2018	June 30, 2017
Basic computation	49,643,954	48,418,368
Dilutive effect of:		
Performance share awards (1)	173,840	129,383
Diluted computation	49,817,794	48,547,751

(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.

(11) Employee Benefit Plans

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

	Pension Benefits		Other Postretirement Benefits	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2018	2017	2018	2017
Components of Net Periodic Benefit Cost (Income)				
Service cost	$ 2,684	$ 2,367	$ 87	$ 100
Interest cost	6,102	6,388	142	178
Expected return on plan assets	(7,044)	(5,974)	(238)	(211)
Amortization of prior service cost	1	—	(470)	(470)
Recognized actuarial loss (gain)	1,108	1,944	(20)	81
Net Periodic Benefit Cost (Income)	$ 2,851	$ 4,725	$ (499)	$ (322)

	Pension Benefits		Other Postretirement Benefits	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Components of Net Periodic Benefit Cost (Income)				
Service cost	$ 5,888	$ 5,497	$ 199	$ 228
Interest cost	12,210	12,817	289	358
Expected return on plan assets	(14,104)	(11,982)	(477)	(424)
Amortization of prior service cost	2	2	(941)	(941)
Recognized actuarial loss (gain)	2,180	3,919	(40)	159
Net Periodic Benefit Cost (Income)	$ 6,176	$ 10,253	$ (970)	$ (620)

We adopted ASU 2017-07 on January 1, 2018. As a result, we recorded the non-service cost component of net periodic benefit cost within other expense, net. This standard requires retrospective adoptions, which resulted in a $2.6 million and $5.2 million reclassification from operating, general and administrative expenses to other expense, net for the three and six months ended June 30, 2017, to conform to current period presentation.

(12) 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, the majority of our environmental reserve relates to the remediation of former manufactured gas plant sites owned by us and is estimated to range between $26.7 million and $31.2 million. As of June 30, 2018, we have a reserve of approximately $29.6 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 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 $22.8 million of our environmental reserve accrual is related to manufactured gas plants. A formerly operated manufactured gas plant located in Aberdeen, South Dakota, has been identified on the Federal Comprehensive Environmental Response, Compensation, and Liability Information System list as contaminated with coal tar residue. We are currently conducting feasibility studies, implementing remedial actions pursuant to work plans approved by the South Dakota Department of Environment and Natural Resources, and conducting ongoing monitoring and operation and maintenance activities. As of June 30, 2018, the reserve for remediation costs at this site is approximately $9.3 million, and we estimate that approximately $4.3 million of this amount will be incurred during the next five years.

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

In addition, we own or have responsibility for sites in Butte, Missoula and Helena, Montana on which former manufactured gas plants were located. The Butte and Helena sites, both listed as high priority sites on Montana's state superfund list, were placed into the Montana Department of Environmental Quality (MDEQ) voluntary remediation program for cleanup due to soil and groundwater impacts. Soil and coal tar were removed at the sites in accordance with the MDEQ requirements. Groundwater monitoring is conducted semiannually at both sites. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of additional remedial actions and/or investigations, if any, at the Butte site. In August 2016, the MDEQ sent us a Notice of Potential Liability and Request for Remedial Action regarding the Helena site. In September 2017, we submitted a Draft Remedial Investigation Work Plan for the Helena site, based on the request of the MDEQ. Comments from the MDEQ are expected before the end of 2018.

An investigation conducted at the Missoula site did not require remediation activities, but required preparation of a groundwater monitoring plan. Monitoring wells have been installed and groundwater is monitored semiannually. At the request of Missoula Valley Water Quality District (MVWQD), a draft risk assessment was prepared for the Missoula site and presented to the MVWQD. We and the MVWQD agreed additional site investigation work is appropriate. Analytical results from an October 2016 sampling exceeded the Montana Maximum Contaminant Level for benzene and/or total cyanide in certain monitoring wells. These results were forwarded to MVWQD which shared the same with the MDEQ. MDEQ requested that MVWQD file a formal complaint with MDEQ's Enforcement Division, which MVWQD filed in July 2017. This is expected to prompt MDEQ to reevaluate its position concerning listing the Missoula site on the State of Montana's superfund list. New landowners purchased a portion of the Missoula site using funding provided by a third party. The terms of the funding require the new landowners to address environmental issues. The new landowners contacted us and we addressed their immediate concerns. After researching historical ownership we have identified another potentially responsible party with whom we have initiated communications regarding the site. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of risk-based remedial action, if any, at the Missoula site.

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

While numerous bills have been introduced that address climate change from different perspectives, including through direct regulation of GHG emissions, the establishment of cap and trade programs and the establishment of Federal renewable portfolio standards, Congress has not passed any federal climate change legislation and we cannot predict the timing or form of any potential legislation. In the absence of such legislation, EPA is presently regulating new and existing sources of GHG emissions through regulations. EPA is currently reviewing its existing regulations as a result of an Executive Order issued by President Trump on March 28, 2017 (the Executive Order) instructing all federal agencies to review all regulations and other policies (specifically including the Clean Power Plan, which is discussed in further detail below) that burden the development or use of domestically produced energy resources and suspend, revise or rescind those that pose an undue burden beyond that required to protect the public interest.

The Clean Power Plan (CPP) was published in October 2015 and was intended to establish GHG performance standards for existing power plants under Clean Air Act Section 111(d). The CPP established CO_2 emission performance standards for existing electric utility steam generating units and natural gas combined cycle units. As a result of the Executive Order review, on October 10, 2017, the EPA proposed to repeal the CPP. Subsequently, the EPA issued an Advance Notice of Proposed Rulemaking, soliciting information on systems of emission reduction that comply with EPA's interpretation of the Clean Air Act, for possible replacement of the CPP, which was published in the Federal Register on December 28, 2017.

Following the issuance of the CPP in October 2015, petitions for review were filed in the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit), including a petition by us. The United States Supreme Court (Supreme Court) issued a stay pending resolution of the case by the D.C. Circuit. Following issuance of the Executive Order, the EPA has requested the D.C. Circuit to hold the case in abeyance. The D.C. Circuit has incrementally granted those requests, most recently in an order issued on June 26, 2018, holding the case in abeyance for an additional 60 days. In that recent order, three of the nine D.C. Circuit Judges expressed they would not vote for further abeyances, absent good reason otherwise. On July 9, 2018, the EPA forwarded its proposed rule replacing the CPP to the Office of Management and Budget (OMB) for interagency review.

In addition, administrative requests for reconsideration of the CPP were filed with the EPA, including one filed by us in December 2015. We requested the EPA reconsider the CPP, in part, on the grounds that the CO_2 reductions in the CPP applicable to Montana were substantially greater than the reductions the EPA had originally proposed. The EPA denied the petition for reconsideration on January 11, 2017, and we appealed that denial to the D.C. Circuit on March 13, 2017. The EPA has also requested that this case be held in abeyance.

We cannot predict what, if any, action the D.C. Circuit may take in either of these two cases, particularly in light of the EPA's proposal to repeal the CPP. If the CPP is not repealed, survives the legal challenges described above, and is implemented as written, or if a replacement to the CPP is adopted with similar requirements, it could result in significant additional compliance costs that would affect our future results of operations and financial position if such costs are not recovered through regulated rates. We will continue working with federal and state regulatory authorities, other utilities, and stakeholders to seek relief from any GHG regulations that, in our view, disproportionately impacts customers in our region.

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

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

On January 10, 2017, the EPA published amendments to the requirements under the Clean Air Act for state plans for protection of visibility. Among other things, these amendments revised the process and requirements for the state implementation plans and extended the due date for the next periodic comprehensive regional haze state implementation plan revisions from 2018 to 2021. Therefore, by 2021, Montana, or EPA, must develop a revised plan that demonstrates reasonable progress toward eliminating man-made emissions of visibility impairing pollutants, which could impact Colstrip Unit 4. In March 2017, we filed a Petition for Review of these amendments with the D.C. Circuit, which was consolidated with other petitions challenging the final rule. While the EPA has not responded to our petition, on January 19, 2018, EPA advised the D.C. Circuit that it intended to initiate rulemaking to revisit the amendment, and asked that the case be held in abeyance. On January 30, 2018, the D.C. Circuit granted the EPA's request to hold the case in abeyance pending further order of the court. On April 27, 2018, the EPA filed a status report with the D.C. Circuit advising it that EPA has continued to assess the rule and expressing the EPA's belief that the case should remain in abeyance while its administrative proceeding continues.

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 CPP, as discussed above, we cannot predict the impact of the CPP on us until there is a definitive judicial decision or administrative action by the EPA repealing or significantly changing the CPP.

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

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

- We may not know all sites for which we are alleged or will be found to be responsible for remediation; and

- Absent performance of certain testing at sites where we have been identified as responsible for remediation, we cannot estimate with a reasonable degree of certainty the total costs of remediation.

LEGAL PROCEEDINGS

Pacific Northwest Solar Litigation

Pacific Northwest Solar, LLC (PNWS) is a solar QF developer seeking to construct small solar facilities in Montana. We began negotiating in early 2016 to purchase the output from these facilities pursuant to our standard QF-1 Tariff, which is applicable to projects greater than 100 kW, but no larger than 3 MW.

On June 16, 2016, however, the MPSC suspended the availability of the QF-1 Tariff standard rates for solar projects, which included the various projects proposed by PNWS. The MPSC exempted from the suspension any projects for which a QF had submitted a signed power purchase agreement and had executed an interconnection agreement. Because PNWS had not executed interconnection agreements for any of its projects as of June 16, 2016, it did not qualify for the exemption.

In November 2016, PNWS sued us in state court seeking unspecified damages for breach of contract and other relief, including a judicial declaration that some or all of 21 proposed power purchase agreements were in effect. We removed the state lawsuit to the United States District Court for the District of Montana.

PNWS also requested the MPSC to exempt its projects from the tariff suspension. We joined in PNWS's request to the MPSC for relief on four of the projects. The MPSC did not grant PNWS or us the relief requested.

On August 14, 2017, PNWS amended its original complaint to seek enforcement and/or damages related to four of the 21 power purchase agreements.

Currently pending before the United States District Court are our motion to dismiss, our motion for partial summary judgment, and PNWS's motion for summary judgment on its request for declaratory relief regarding those four power purchase agreements.

We dispute the remaining claims in PNWS' lawsuit and intend to vigorously defend those claims. This matter is in the initial stages, and we cannot predict an outcome or estimate the amount or range of loss that would result from an adverse outcome in the remaining claims.

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 claims 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 in the litigation 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 and following briefing and argument, on October 10, 2017, the Federal District Court Judge entered an order denying the State's motion. As 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. The motions to dismiss have been fully briefed and argued and are awaiting decision.

We dispute the State's claims and intend to vigorously defend the lawsuit. This matter is in the initial stages, and we cannot predict an outcome. If the Federal District Court determines the riverbeds under all 10 of the hydroelectric facilities are navigable (including the five hydroelectric facilities on the Great Falls Reach) and if it calculates damages as the State District Court did in 2008, we estimate the annual rents could be approximately $7 million commencing in November 2014, when we acquired the facilities. 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.

Wilde Litigation

On October 10, 2017, Martin Wilde, a Montana resident and wind developer, and three entities with which he is affiliated, commenced a lawsuit against the MPSC, each individual commissioner of the MPSC (in each of their official and individual capacities), and NorthWestern in the Montana Eighth Judicial District Court (Eighth District Court). The plaintiffs allege that the MPSC collaborated with NorthWestern to set discriminatory rates and contract durations for QF developers. The plaintiffs seek power purchase agreements at $45.19 per megawatt hour for a 25-year term or, as an alternative remedy to the alleged discrimination, a reduction in NorthWestern's rates by $17.03 per megawatt hour. The plaintiffs also seek compensatory damages of not less than $4.8 million, various forms of declaratory relief, injunctive relief, unspecified damages, and punitive damages.

On October 20, 2017, the Eighth District Court conducted a hearing on the plaintiffs' application for a preliminary injunction to stop the defendants from the alleged ongoing discrimination that harms development of renewable energy in Montana. At the hearing's conclusion, the court did not rule on the requested injunction but orally ordered post-hearing briefs and set deadlines for answers and dispositive motions. On November 11, 2017, Mr. Wilde died in a farming accident, and, at plaintiffs' request, the Eighth District Court stayed the proceeding through May 11, 2018. On May 10, 2018, the plaintiffs requested a status conference to determine a schedule and next steps for this litigation. The Court has not set a status conference.

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 718,300 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, 2017.

As you read this discussion and analysis, refer to our Condensed Consolidated Statements of Income, which present the results of our operations for 2018 and 2017.

HOW WE PERFORMED AGAINST OUR SECOND QUARTER 2017 RESULTS

	Quarter-over-Quarter Change		
Gross Margin by Segment[(1)]			
Electric	$26.3M	↑	16.1%
Natural Gas	$3.4M	↑	9.4%
Operating Income	$22.9M	↑	49.5%
Net Income	$22.0M	↑	100.6%
Diluted Earnings per Average Common Share	$0.43	↑	97.7%

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

For the second quarter of 2018, we had an increase in net income of approximately $22 million, primarily due to a gain related to the adjustment of our QF liability and favorable weather, and to a lesser extent increased demand for electric transmission.

Following is a brief overview of significant items for 2018.

SIGNIFICANT TRENDS AND REGULATION

Tax Cuts and Jobs Act

In December 2017, the Tax Cuts and Jobs Act was signed into law, which enacts significant changes to U.S. tax and related laws. The primary impact to us is a reduction of the federal corporate income tax rate from 35% to 21% effective January 1, 2018. In each of our jurisdictions, we expect the Tax Cuts and Jobs Act related credits to continue and be subject to true-up until base rates are reset in a general rate case filing or agreement is reached with our state regulatory commissions as to how the impact of the Tax Cuts and Job Act will be resolved.

As of June 30, 2018, we have deferred revenue of approximately $13.5 million associated with the impacts of the Tax Cuts and Jobs Act. For purposes of the filings discussed below, we calculated the customer benefit using two alternate methods based on current and historic test periods. The revenue deferral is based upon our 2018 estimated impact of Tax Cuts and Jobs Act of approximately $18 million to $23 million and is offset by a corresponding reduction in income tax expense. Application of the historic method would result in customer refunds that exceed the reduction in our 2018 taxes, which would be an additional reduction in pretax earnings and cash flows ranging from approximately $5 million to $10 million.

We cannot predict how each jurisdiction may calculate the amount of credits due to customers. If any of our regulatory jurisdictions determines the credits due to customers are higher than the expected reduction to income tax expense, this would result in an adverse impact to results of operations and cash flows.

Cost Recovery Mechanisms

Montana House Bill 193 / Electric Tracker - In April 2017, the Montana legislature passed HB 193, amending the statute that provided for mandatory recovery of our prudently incurred electric supply costs effective July 1, 2017. The revised statute gives the MPSC discretion whether to approve an electric supply cost adjustment mechanism. The MPSC initiated a process to develop a replacement electric supply cost adjustment mechanism, and in response, in July 2017, we filed a proposed electric PCCAM. In December 2017, after the intervenors filed testimony, the MPSC issued a Notice of Additional Issues stating that the range of options proposed by the parties was not sufficient and directing parties to consider alternatives incorporating risk-sharing features of other utilities in the region.

We filed testimony in February 2018, responsive to both the intervenors' testimony and the MPSC's Notice of Additional Issues addressing alternative risk-sharing mechanisms. Intervenors filed testimony on the Notice of Additional Issues in March 2018. The MPSC held a hearing during the second quarter of 2018, and we expect a decision in the matter no later than the fourth quarter of 2018. If the MPSC approves a new mechanism, the MPSC may apply the mechanism to variable costs on a retroactive basis to the effective date of HB 193 (July 1, 2017).

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 exclude (or include) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. We define Gross Margin as Revenues less Cost of Sales as presented in our Condensed Consolidated Statements of Income.

Management believes that Gross Margin (revenues less cost of sales) 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, and as a result do not typically impact operating or net income. In addition, Gross Margin is used by us to determine whether we are collecting the appropriate amount of energy costs from customers to allow 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 June 30, 2018 Compared with the Three Months Ended June 30, 2017

	Electric		Natural Gas		Total	
	2018	2017	2018	2017	2018	2017
			(dollars in millions)			
Reconciliation of gross margin to operating revenue:						
Operating Revenues	$ 209.7	$ 233.9	$ 52.1	$ 50.0	$ 261.8	$ 283.9
Cost of Sales	19.6	70.1	12.6	13.9	32.2	84.0
Gross Margin(1)	**$ 190.1**	**$ 163.8**	**$ 39.5**	**$ 36.1**	**$ 229.6**	**$ 199.9**

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

	Three Months Ended June 30,			
	2018	2017	Change	% Change
	(dollars in millions)			
Gross Margin				
Electric	$ 190.1	$ 163.8	$ 26.3	16.1 %
Natural Gas	39.5	36.1	3.4	9.4
Total Gross Margin(1)	**$ 229.6**	**$ 199.9**	**$ 29.7**	**14.9%**

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

Primary components of the change in gross margin, defined as revenues less cost of sales, include the following:

	Gross Margin 2018 vs. 2017
	(in millions)
Gross Margin Items Impacting Net Income	
Electric QF liability adjustment	$ 25.1
Electric and natural gas retail volumes	4.0
Electric transmission	1.4
Montana natural gas and production rates	0.3
Other	1.3
Change in Gross Margin Impacting Net Income	**32.1**
Gross Margin Items Offset in Operating and Income Tax Expense	
Tax Cuts and Jobs Act deferral	(6.2)
Natural gas production gathering fees	(0.4)
Property taxes recovered in trackers	3.5
Production tax credits flowed-through trackers	0.7
Change in Items Offset Within Net Income	**(2.4)**
Increase in Gross Margin(1)	**$ 29.7**

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

Consolidated gross margin for items impacting net income increased $32.1 million due to the following items:

- A reduction in the electric QF liability due to the combination of (i) a periodic adjustment of the liability for price escalation, which was less than modeled resulting in a liability reduction of approximately $17.5 million; and (ii) the annual reset to actual output and pricing resulting in approximately $7.6 million in lower QF related supply costs due primarily to outages at two facilities. Our electric QF liability consists of unrecoverable costs associated with contracts covered under PURPA that are part of a 2002 stipulation with the MPSC and other parties;
- An increase in electric and natural gas retail volumes due primarily to favorable weather and customer growth;

- Higher demand to transmit energy across our transmission lines due to market conditions and pricing; and
- An increase in our Montana gas rates effective September 1, 2017.

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

- A decrease due to the deferral of revenue as a result of the Tax Cuts and Job Act, offset by a decrease in income tax expense;
- A decrease in natural gas production gathering fees, offset by reduced operating expenses;
- An increase in revenues for property taxes included in trackers, offset by increased property tax expense; and
- An increase in revenue due to the decrease in production tax credit benefits passed through to customers in our tracker mechanisms, which are offset by increased income tax expense.

	Three Months Ended June 30,			
	2018	2017	Change	% Change
	(dollars in millions)			
Operating Expenses (excluding cost of sales)				
Operating, general and administrative	$ 73.8	$ 72.6	$ 1.2	1.7 %
Property and other taxes	43.0	39.5	3.5	8.9
Depreciation and depletion	43.5	41.5	2.0	4.8
	$ 160.3	**$ 153.6**	**$ 6.7**	**4.4%**

Consolidated operating, general and administrative expenses were $73.8 million for the three months ended June 30, 2018, as compared with $72.6 million for the three months ended June 30, 2017. Primary components of the change include the following:

	Operating, General & Administrative Expenses
	2018 vs. 2017
	(in millions)
Employee benefits	$ 2.7
Maintenance Costs	(2.0)
Labor	(1.0)
Distribution System Infrastructure Project expenses	(0.7)
Natural gas production gathering expense	(0.4)
Other	(0.5)
Operating, General & Administrative Expenses impacting Net Income	**(1.9)**
Operating, General & Administrative Expenses Offset in Other Income	
Pension and other postretirement benefits	2.6
Non-employee directors deferred compensation	0.5
Change in Items Offset Within Other Income	**3.1**
Increase in Operating, General & Administrative Expenses	**$ 1.2**

Consolidated operating, general and administrative expenses for items impacting net income decreased $1.9 million due to the following:

- An increase in employee benefit costs primarily due to higher medical and pension expense;
- Lower maintenance costs at generation facilities;
- Decreased labor costs due primarily to more time being spent by employees on capital rather than maintenance projects (which are expensed);
- Lower Distribution System Infrastructure Project related expenses, which concluded in 2017; and
- Lower gas production gathering expense (offset by lower gathering fees discussed above).

The change in consolidated operating, general and administrative expenses also includes the following items that are offset in other income (expense) below and had no impact on net income:

- The regulatory treatment of the non-service cost components of pension and postretirement benefit expense; and
- The change in value of non-employee directors deferred compensation due to changes in our stock price.

Property and other taxes were $43.0 million for the three months ended June 30, 2018, as compared with $39.5 million in the same period of 2017. This increase was primarily due to plant additions and higher estimated property valuations in Montana. We estimate property taxes throughout each year, and update based on valuation reports received from the Montana Department of Revenue. Under Montana law, we are allowed to track the increases in the actual level of state and local taxes and fees and adjust our rates to recover the increase between rate cases less the amount allocated to FERC-jurisdictional customers and net of the associated income tax benefit.

Depreciation and depletion expense was $43.5 million for the three months ended June 30, 2018, as compared with $41.5 million in the same period of 2017. This increase was primarily due to plant additions.

Consolidated operating income for the three months ended June 30, 2018 was $69.2 million as compared with $46.3 million in the same period of 2017. This increase was primarily due to the adjustment of our QF liability and favorable weather, partly offset by the overall increase in operating expenses, as discussed above.

Consolidated interest expense for the three months ended June 30, 2018 was $23.2 million, as compared with $23.4 million in the same period of 2017, with a decrease from the refinancing of debt in 2017 partly offset by rising interest rates.

Consolidated other income was $0.9 million for the three months ended June 30, 2018 as compared to consolidated other expense of $0.5 million during the same period of 2017. This improvement includes a decrease in other pension expense and an increase in the value of deferred shares held in trust for non-employee directors deferred compensation, both of which are offset in operating, general, and administrative expenses with no impact to net income. These improvements were partly offset by lower capitalization of Allowance for Funds Used During Construction (AFUDC).

Consolidated income tax expense for the three months ended June 30, 2018 was $3.1 million as compared with $0.6 million in the same period of 2017. Our effective tax rate for the three months ended June 30, 2018 was 6.6% as compared with 2.6% for the same period of 2017. We expect our 2018 effective tax rate to range between 0% - 5%.

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

	Three Months Ended June 30,			
	2018		2017	
Income Before Income Taxes	$ 46.9		$ 22.4	
Income tax calculated at federal statutory rate	9.8	21.0%	7.8	35.0%
Permanent or flow through adjustments:				
State income, net of federal provisions	0.8	1.7	(0.5)	(2.2)
Flow-through repairs deductions	(4.1)	(8.7)	(4.7)	(21.2)
Production tax credits	(2.5)	(5.5)	(1.4)	(6.5)
Plant and depreciation of flow through items	(0.6)	(1.2)	(0.7)	(3.1)
Other, net	(0.3)	(0.7)	0.1	0.6
	(6.7)	(14.4)	(7.2)	(32.4)
Income Tax Expense	$ 3.1	6.6%	$ 0.6	2.6%

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 June 30, 2018 was $43.8 million as compared with $21.8 million for the same period in 2017. This increase was primarily due to a gain related to the adjustment of our QF liability and favorable weather, partly offset by the overall increase in operating expenses and higher income tax expense, as discussed above.

Six Months Ended June 30, 2018 Compared with the Six Months Ended June 30, 2017

	Electric		Natural Gas		Total	
	2018	2017	2018	2017	2018	2017
			(dollars in millions)			
Reconciliation of gross margin to operating revenue:						
Operating Revenues	$ 448.1	$ 500.1	$ 155.2	$ 151.1	$ 603.3	$ 651.2
Cost of Sales	76.9	155.5	51.4	48.3	128.3	203.8
Gross Margin[(1)]	**$ 371.2**	**$ 344.6**	**$ 103.8**	**$ 102.8**	**$ 475.0**	**$ 447.4**

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

	Six Months Ended June 30,			
	2018	2017	Change	% Change
		(dollars in millions)		
Gross Margin				
Electric	$ 371.2	$ 344.6	$ 26.6	7.7%
Natural Gas	103.8	102.8	1.0	1.0
Total Gross Margin[(1)]	**$ 475.0**	**$ 447.4**	**$ 27.6**	**6.2%**

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

Primary components of the change in gross margin include the following:

	Gross Margin 2018 vs. 2017
	(in millions)
Gross Margin Items Impacting Net Income	
Electric QF liability adjustment	$ 25.1
Electric and natural gas retail volumes	5.5
Electric transmission	2.9
Montana natural gas and production rates	2.2
Other	0.5
Change in Gross Margin Impacting Net Income	**36.2**
Gross Margin Items Offset in Operating Expenses	
Tax Cuts and Jobs Act deferral	(13.5)
Natural gas production gathering fees	(0.4)
Property taxes recovered in trackers	4.1
Production tax credits flowed-through trackers	1.2
Change in Items Offset Within Net Income	**(8.6)**
Increase in Gross Margin	**$ 27.6**

Consolidated gross margin for items impacting net income increased $36.2 million, due to the following:

- A reduction in the electric QF liability due to the combination of (i) a periodic adjustment of the liability for price escalation, which was less than modeled resulting in a liability reduction of approximately $17.5 million; and (ii) the annual reset to actual output and pricing resulting in approximately $7.6 million in lower QF related supply costs due to outages at two facilities;
- An increase in electric and natural gas retail volumes due primarily to favorable weather and customer growth;
- Higher demand to transmit energy across our transmission lines due to market conditions and pricing; and
- An increase in our Montana gas rates effective September 1, 2017.

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

- A decrease due to the deferral of revenue as a result of the Tax Cuts and Job Act, offset by a decrease in income tax expense;
- A decrease in natural gas production gathering fees, offset by reduced operating expenses;
- An increase in revenues for property taxes included in trackers, offset by increased property tax expense; and
- An increase in revenue due to the decrease in production tax credit benefits passed through to customers in our tracker mechanisms, which are offset by increased income tax expense.

	Six Months Ended June 30,			
	2018	**2017**	**Change**	**% Change**
	(dollars in millions)			
Operating Expenses (excluding cost of sales)				
Operating, general and administrative	$ 148.2	$ 150.9	$ (2.7)	(1.8)%
Property and other taxes	85.9	79.4	6.5	8.2
Depreciation and depletion	87.3	83.0	4.3	5.2
	$ 321.4	**$ 313.3**	**$ 8.1**	**2.6 %**

Consolidated operating, general and administrative expenses were $148.2 million for the six months ended June 30, 2018, as compared with $150.9 million for the six months ended June 30, 2017. Primary components of the change include the following:

	Operating, General & Administrative Expenses
	2018 vs. 2017
	(in millions)
Maintenance Costs	$ (3.5)
Labor	(2.2)
Distribution System Infrastructure Project expenses	(1.7)
Natural gas production gathering expense	(0.4)
Employee benefits	2.9
Other	(1.3)
Operating, General & Administrative Expenses impacting Net Income	**(6.2)**
Operating, General & Administrative Expenses Offset in Other Income	
Pension and other postretirement benefits	5.3
Non-employee directors deferred compensation	(1.8)
Change in Items Offset Within Other Income	**3.5**
Decrease in Operating, General & Administrative Expenses	$ (2.7)

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

- Lower maintenance costs at electric generating facilities;
- Decreased labor costs due primarily to more time being spent by employees on capital rather than maintenance projects (which are expensed);
- Lower Distribution System Infrastructure Project related expenses, which concluded in 2017; and
- Lower gas production gathering expense (offset by lower gathering fees discussed above).

These decreases were partly offset by an increase in employee benefit costs primarily due to higher medical and pension expense.

The change in consolidated operating, general and administrative expenses also includes the following items that are offset in other income (expense) below and had no impact on net income:

- The regulatory treatment of the non-service cost components of pension and postretirement benefit expense; and
- The change in value of non-employee directors deferred compensation due to changes in our stock price.

Property and other taxes were $85.9 million for the six months ended June 30, 2018, as compared with $79.4 million in the same period of 2017. This increase was primarily due to plant additions and higher estimated property valuations in Montana. We expect property tax expense to increase by approximately $7.0 million on an annual basis in 2018 as compared with 2017.

Depreciation and depletion expense was $87.3 million for the six months ended June 30, 2018, as compared with $83.0 million in the same period of 2017. This increase was primarily due to plant additions.

Consolidated operating income for the six months ended June 30, 2018 was $153.7 million as compared with $134.1 million in the same period of 2017. This increase was primarily due to the adjustment of our electric QF liability and favorable weather, partly offset by the overall increase in operating expenses, as discussed above.

Consolidated interest expense for the six months ended June 30, 2018 was $46.2 million, as compared with $46.8 million in the same period of 2017. This decrease was primarily due to the refinancing of debt in 2017, partly offset by rising interest rates.

Consolidated other expense for the six months ended June 30, 2018, was $0.3 million, as compared with $1.6 million in the same period of 2017. This includes a decrease in other pension expense, partly offset by a decrease in the value of deferred shares held in trust for non-employee directors deferred compensation (both of which are offset in operating, general and administrative expenses with no impact to net income) and lower capitalization of AFUDC.

Consolidated income tax expense for the six months ended June 30, 2018 was $5.0 million, as compared with $7.3 million in the same period of 2017. Our effective tax rate for the six months ended June 30, 2018 was 4.7% as compared with 8.5% for the same period of 2017.

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

	Six Months Ended June 30,			
	2018		2017	
Income Before Income Taxes	$ 107.3		$ 85.7	
Income tax calculated at federal statutory rate	22.5	21.0%	30.0	35.0%
Permanent or flow through adjustments:				
State income, net of federal provisions	1.5	1.5	(1.3)	(1.5)
Flow-through repairs deductions	(10.7)	(10.0)	(13.6)	(15.8)
Production tax credits	(6.4)	(6.0)	(5.3)	(6.2)
Plant and depreciation of flow through items	(1.5)	(1.4)	(2.1)	(2.5)
Share-based compensation	0.3	0.3	(0.4)	(0.5)
Other, net	(0.7)	(0.7)	—	—
	(17.5)	(16.3)	(22.7)	(26.5)
Income Tax Expense	$ 5.0	4.7%	$ 7.3	8.5%

Consolidated net income for the six months ended June 30, 2018 was $102.3 million as compared with $78.4 million for the same period in 2017. This increase was primarily due to a gain related to the adjustment of our electric QF liability, favorable weather, and lower income tax expense, partly offset by the overall increase in operating expenses, as discussed above.

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 June 30, 2018 Compared with the Three Months Ended June 30, 2017

	Results			
	2018	2017	Change	% Change
	(dollars in millions)			
Retail revenues	$ 193.6	$ 196.0	$ (2.4)	(1.2)%
Regulatory amortization	(1.3)	4.5	(5.8)	(128.9)
Total retail revenues	192.3	200.5	(8.2)	(4.1)
Transmission	16.2	13.1	3.1	23.7
Wholesale and Other	1.2	20.3	(19.1)	(94.1)
Total Revenues	**209.7**	**233.9**	**(24.2)**	**(10.3)**
Total Cost of Sales	**19.6**	**70.1**	**(50.5)**	**(72.0)**
Gross Margin[(1)]	**$ 190.1**	**$ 163.8**	**$ 26.3**	**16.1 %**

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

	Revenues		Megawatt Hours (MWH)		Avg. Customer Counts	
	2018	2017	2018	2017	2018	2017
	(in thousands)					
Montana	$ 59,480	$ 59,740	516	503	298,897	294,721
South Dakota	14,385	12,832	130	110	50,493	50,158
Residential	**73,865**	**72,572**	**646**	**613**	**349,390**	**344,879**
Montana	79,648	83,028	762	764	67,339	66,277
South Dakota	22,271	21,400	250	230	12,804	12,687
Commercial	**101,919**	**104,428**	**1,012**	**994**	**80,143**	**78,964**
Industrial	10,714	10,087	600	554	75	75
Other	7,140	8,920	36	51	6,026	6,205
Total Retail Electric	**$ 193,638**	**$ 196,007**	**2,294**	**2,212**	**435,634**	**430,123**

	Cooling Degree Days			2018 as compared with:	
	2018	2017	Historic Average	2017	Historic Average
Montana	32	57	55	44% colder	42% colder
South Dakota	167	91	51	84% warmer	227% warmer

	Heating Degree Days			2018 as compared with:	
	2018	2017	Historic Average	2017	Historic Average
Montana	1,089	1,061	1,195	3% colder	9% warmer
South Dakota	1,712	1,321	1,535	30% colder	12% colder

The following summarizes the components of the changes in electric gross margin for the three months ended June 30, 2018 and 2017:

		Gross Margin 2018 vs. 2017
		(in millions)
Gross Margin Items Impacting Net Income		
QF liability adjustment	$	25.1
Retail volumes		2.5
Transmission		1.4
Other		0.9
Change in Gross Margin Impacting Net Income		29.9
Gross Margin Items Offset in Operating Expenses		
Tax Cuts and Jobs Act deferral		(7.0)
Property taxes recovered in trackers		2.7
Production tax credits flowed-through trackers		0.7
Change in Items Offset Within Net Income		(3.6)
Increase in Gross Margin[1]	**$**	**26.3**

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

Gross margin for items impacting net income increased $29.9 million including the following:

- A reduction in the QF liability due to the combination of (i) a periodic adjustment of the liability for price escalation, which was less than modeled resulting in a liability reduction of approximately $17.5 million; and (ii) the annual reset to actual output and pricing resulting in approximately $7.6 million in lower QF related supply costs due to outages at two facilities;
- An increase in retail volumes due primarily to favorable weather and customer growth; and
- Higher demand to transmit energy across our transmission lines due to market conditions and pricing.

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

- A decrease due to the deferral of revenue as a result of the Tax Cuts and Job Act, offset by a decrease in income tax expense;
- An increase in revenues for property taxes included in trackers, offset by increased property tax expense; and
- An increase in revenue due to the decrease in production tax credit benefits passed through to customers in our tracker mechanisms, which are offset by increased income tax expense.

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. In addition, while heating and cooling degree days may fluctuate significantly during the second quarter, our electric customer usage is not highly sensitive to these changes between the heating and cooling seasons. Our wholesale and other revenues are largely gross margin neutral as they are offset by changes in cost of sales.

Six Months Ended June 30, 2018 Compared with the Six Months Ended June 30, 2017

	Results			
	2018	2017	Change	% Change
	(dollars in millions)			
Retail revenues	$ 423.0	$ 430.7	$ (7.7)	(1.8)%
Regulatory amortization	(9.4)	(0.7)	(8.7)	(1,242.9)
Total retail revenues	413.6	430.0	(16.4)	(3.8)
Transmission	31.5	25.5	6.0	23.5
Wholesale and Other	3.0	44.6	(41.6)	(93.3)
Total Revenues	**448.1**	**500.1**	**(52.0)**	**(10.4)**
Total Cost of Sales	**76.9**	**155.5**	**(78.6)**	**(50.5)**
Gross Margin[(1)]	**$ 371.2**	**$ 344.6**	**$ 26.6**	**7.7 %**

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

	Revenues		Megawatt Hours (MWH)		Avg. Customer Counts	
	2018	2017	2018	2017	2018	2017
	(in thousands)					
Montana	$ 146,731	$ 150,548	1,277	1,264	298,631	294,471
South Dakota	33,068	30,168	317	289	50,500	50,167
Residential	**179,799**	**180,716**	**1,594**	**1,553**	**349,131**	**344,638**
Montana	163,287	171,136	1,566	1,579	67,261	66,194
South Dakota	46,282	43,810	520	485	12,727	12,616
Commercial	**209,569**	**214,946**	**2,086**	**2,064**	**79,988**	**78,810**
Industrial	21,476	20,952	1,207	1,132	75	75
Other	12,137	14,057	58	74	5,381	5,443
Total Retail Electric	**$ 422,981**	**$ 430,671**	**4,945**	**4,823**	**434,575**	**428,966**

	Cooling Degree Days			2018 as compared with:	
	2018	2017	Historic Average	2017	Historic Average
Montana	32	57	55	44% colder	42% colder
South Dakota	167	91	51	84% warmer	227% warmer

	Heating Degree Days			2018 as compared with:	
	2018	2017	Historic Average	2017	Historic Average
Montana	4,697	4,437	4,373	6% colder	7% colder
South Dakota	6,076	5,211	5,574	17% colder	9% colder

The following summarizes the components of the changes in electric gross margin for the six months ended June 30, 2018 and 2017:

	Gross Margin 2018 vs. 2017 (in millions)
Gross Margin Items Impacting Net Income	
QF liability adjustment	$ 25.1
Retail volumes	3.6
Transmission	2.9
Other	1.0
Change in Gross Margin Impacting Net Income	32.6
Gross Margin Items Offset in Operating Expenses	
Tax Cuts and Jobs Act deferral	(11.5)
Property taxes recovered in trackers	4.3
Production tax credits flowed-through trackers	1.2
Change in Items Offset Within Net Income	(6.0)
Increase in Gross Margin	**$ 26.6**

Gross margin for items impacting net income increased $32.6 million including the following:

- A reduction in the QF liability due to the combination of (i) a periodic adjustment of the liability for price escalation, which was less than modeled resulting in a liability reduction of approximately $17.5 million; and (ii) the annual reset to actual output and pricing resulting in approximately $7.6 million in lower QF related supply costs due to outages at two facilities;
- An increase in retail volumes due primarily to favorable weather and customer growth; and
- Higher demand to transmit energy across our transmission lines due to market conditions and pricing.

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

- A decrease due to the deferral of revenue as a result of the Tax Cuts and Job Act, offset by a decrease in income tax expense;
- An increase in revenues for property taxes included in trackers, offset by increased property tax expense; and
- An increase in revenue due to the decrease in production tax credit benefits passed through to customers in our tracker mechanisms, which are offset by increased income tax expense.

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 June 30, 2018 Compared with the Three Months Ended June 30, 2017

	Results			
	2018	2017	Change	% Change
	(dollars in millions)			
Retail revenues	$ 43.4	$ 38.2	$ 5.2	13.6 %
Regulatory amortization	(1.9)	2.0	(3.9)	(195.0)
Total retail revenues	41.5	40.2	1.3	3.2
Wholesale and other	10.6	9.8	0.8	8.2
Total Revenues	**52.1**	**50.0**	**2.1**	**4.2**
Total Cost of Sales	**12.6**	**13.9**	**(1.3)**	**(9.4)**
Gross Margin[(1)]	**$ 39.5**	**$ 36.1**	**$ 3.4**	**9.4%**

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

	Revenues		Dekatherms (Dkt)		Customer Counts	
	2018	2017	2018	2017	2018	2017
	(in thousands)					
Montana	$ 17,574	$ 16,507	2,093	1,981	172,638	170,311
South Dakota	5,607	4,297	701	512	39,582	39,436
Nebraska	4,991	4,104	591	436	37,269	37,192
Residential	**28,172**	**24,908**	**3,385**	**2,929**	**249,489**	**246,939**
Montana	8,779	8,211	1,109	1,034	23,896	23,548
South Dakota	3,645	2,750	692	521	6,668	6,536
Nebraska	2,413	2,057	426	342	4,813	4,765
Commercial	**14,837**	**13,018**	**2,227**	**1,897**	**35,377**	**34,849**
Industrial	181	156	24	21	244	252
Other	208	165	31	24	163	158
Total Retail Gas	**$ 43,398**	**$ 38,247**	**5,667**	**4,871**	**285,273**	**282,198**

	Heating Degree Days			2018 as compared with:	
	2018	2017	Historic Average	2017	Historic Average
Montana	1,128	1,133	1,243	Remained flat	9% warmer
South Dakota	1,712	1,321	1,535	30% colder	12% colder
Nebraska	1,328	1,028	1,257	29% colder	6% colder

The following summarizes the components of the changes in natural gas gross margin for the three months ended June 30, 2018 and 2017:

	Gross Margin 2018 vs. 2017
	(in millions)
Gross Margin Items Impacting Net Income	
Retail volumes	$ 1.5
Montana rates	0.3
Other	0.4
Change in Gross Margin Impacting Net Income	2.2
Gross Margin Items Offset in Operating Expenses	
Tax Cuts and Jobs Act deferral	0.8
Property taxes recovered in trackers	0.8
Production gathering fees	(0.4)
Change in Items Offset Within Net Income	1.2
Increase in Gross Margin[(1)]	**$ 3.4**

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

Gross margin for items impacting net income increased $2.2 million including the following:

- An increase in retail volumes due primarily to favorable weather and customer growth; and
- An increase in our Montana gas rates effective September 1, 2017.

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

- An increase due to the deferral of revenue as a result of the Tax Cuts and Job Act is offset by an increase in income tax expense;
- An increase in revenues for property taxes included in trackers, offset by increased property tax expense; and
- A decrease in natural gas production gathering fees (offset by reduced operating expenses).

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

Six Months Ended June 30, 2018 Compared with the Six Months Ended June 30, 2017

	Results			
	2018	2017	Change	% Change
	(dollars in millions)			
Retail revenues	$ 142.6	$ 137.1	$ 5.5	4.0 %
Regulatory amortization	(8.2)	(6.6)	(1.6)	(24.2)
Total retail revenues	134.4	130.5	3.9	3.0
Wholesale and other	20.8	20.6	0.2	1.0
Total Revenues	**155.2**	**151.1**	**4.1**	**2.7**
Total Cost of Sales	**51.4**	**48.3**	**3.1**	**6.4**
Gross Margin[(1)]	**$ 103.8**	**$ 102.8**	**$ 1.0**	**1.0%**

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

	Revenues		Dekatherms (Dkt)		Customer Counts	
	2018	2017	2018	2017	2018	2017
	(in thousands)					
Montana	$ 58,477	$ 60,275	7,998	7,903	172,495	170,238
South Dakota	17,025	15,101	2,376	2,027	39,740	39,563
Nebraska	16,404	13,134	2,007	1,684	37,424	37,332
Residential	**91,906**	**88,510**	**12,381**	**11,614**	**249,659**	**247,133**
Montana	29,311	30,144	4,193	4,125	23,881	23,550
South Dakota	11,456	10,179	2,167	1,856	6,694	6,558
Nebraska	8,529	6,969	1,408	1,216	4,839	4,793
Commercial	**49,296**	**47,292**	**7,768**	**7,197**	**35,414**	**34,901**
Industrial	720	662	107	93	246	254
Other	651	612	105	95	163	158
Total Retail Gas	**$ 142,573**	**$ 137,076**	**20,361**	**18,999**	**285,482**	**282,446**

	Heating Degree Days			2018 as compared with:	
	2018	2017	Historic Average	2017	Historic Average
Montana	4,677	4,601	4,480	2% colder	4% colder
South Dakota	6,076	5,211	5,574	17% colder	9% colder
Nebraska	4,928	4,110	4,611	20% colder	7% colder

The following summarizes the components of the changes in natural gas gross margin for the six months ended June 30, 2018 and 2017:

	Gross Margin 2018 vs. 2017 (in millions)
Gross Margin Items Impacting Net Income	
Montana rates	$ 2.2
Retail volumes	1.9
Other	(0.5)
Change in Gross Margin Impacting Net Income	3.6
Gross Margin Items Offset in Operating Expenses	
Tax Cuts and Jobs Act deferral	(2.0)
Production gathering fees	(0.4)
Property taxes recovered in trackers	(0.2)
Change in Items Offset Within Net Income	(2.6)
Increase in Gross Margin[(1)]	**$ 1.0**

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

Gross margin for items impacting net income increased $3.6 million including the following:

- An increase in our Montana gas rates effective September 1, 2017; and
- An increase in retail volumes due primarily to favorable weather and customer growth.

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

- A decrease due to the deferral of revenue as a result of the Tax Cuts and Job Act is offset by a decrease in income tax expense;
- A decrease in natural gas production gathering fees, offset by reduced operating expenses; and
- A decrease in revenues for property taxes included in trackers, offset by decreased property tax expense.

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

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Funds

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

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

In September 2017, we entered into an Equity Distribution Agreement with Merrill Lynch, Pierce, Fenner & Smith Incorporated and J.P. Morgan Securities LLC, collectively the sales agents, pursuant to which we offered and sold shares of our common stock from time to time, having an aggregate gross sales price of up to $100 million. During the three months ended June 30, 2018, we issued 835,765 shares of our common stock at an average price of $54.45, for net proceeds of $44.9 million, which is net of sales commissions and other fees paid of approximately $0.6 million. These issuances concluded this program. Since inception of the program, we sold 1,724,703 shares of our common stock at an average price of $57.98 per share. Net proceeds received were approximately $98.6 million, which are net of sales commissions and other fees paid of approximately $1.4 million.

We plan to maintain a 50 - 55 percent debt to total capital ratio excluding capital 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.

Liquidity is provided by internal cash flows and the use of our revolving credit facilities. We have a $400 million revolving credit facility. In addition, on March 27, 2018, we entered into a $25 million revolving credit facility, maturing March 27, 2020, to provide swingline borrowing capability. We utilize availability under our revolvers to manage our cash flows due to the seasonality of our business, and utilize any cash on hand in excess of current operating requirements to invest in our business and reduce borrowings. We also may use borrowings under our revolvers to temporarily fund utility capital requirements. As of June 30, 2018, our total net liquidity was approximately $214.6 million, including $5.6 million of cash and $209.0 million of revolving credit facility availability. Availability under our revolving credit facilities was $213.0 million as of July 13, 2018.

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 the market prices of our electric and natural gas supply, which is currently recovered through various monthly cost tracking mechanisms. These energy supply tracking mechanisms are designed to provide stable and timely recovery of supply costs on a monthly basis during the July to June annual tracking period, with an adjustment in the following annual tracking period to correct for any under or over collection in our monthly trackers. 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 usually 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. In 2017, a Montana statute that provided for mandatory recovery of our prudently incurred electric supply costs was amended, and that statute now gives the MPSC discretion as to whether to approve electric supply costs. The MPSC opened a new docket and initiated a process to develop a new electric supply recovery mechanism.

As of June 30, 2018, we are over collected on our supply trackers by approximately $3.2 million. We were under collected on our supply trackers by $13.2 million as of December 31, 2017 and $6.5 million as of June 30, 2017.

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 Standard and Poor's Ratings Service (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 July 13, 2018, our current ratings with these agencies are as follows:

	Senior Secured Rating	Senior Unsecured Rating	Commercial Paper	Outlook
Fitch (1)	A	A-	F2	Negative
Moody's (2)	A3	Baa2	Prime-2	Stable
S&P	A-	BBB	A-2	Stable

(1) In February 2018, Fitch affirmed our ratings, but revised our outlook from stable to negative citing continued regulatory headwinds in Montana and expected weakness in leverage metrics through 2021. Fitch also indicated an adverse outcome in either our Montana electric supply tracker docket or upcoming electric general rate case would likely result in a one-notch downgrade.

(2) In May 2018, Moody's downgraded our senior secured rating to A3 from A2, and our unsecured credit rating to Baa2 from Baa1 and revised our outlook from negative to stable. Moody's cited an extended period of weak financial metrics and challenging regulatory relationship in Montana as reasons for the downgrade.

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):

	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Operating Activities		
Net income	$ 102.3	$ 78.4
Non-cash adjustments to net income	96.9	92.8
Changes in working capital	57.1	10.8
Other noncurrent assets and liabilities	(9.1)	(3.0)
Cash Provided by Operating Activities	**247.2**	**179.0**
Investing Activities		
Property, plant and equipment additions	(116.5)	(119.1)
Acquisitions	(18.5)	—
Proceeds from sale of assets	—	0.4
Cash Used in Investing Activities	**(135.0)**	**(118.7)**
Financing Activities		
Proceeds from issuance of common stock, net	44.9	—
Line of credit borrowings, net	216.0	—
(Repayments) issuances of short-term borrowings, net	(319.6)	2.8
Dividends on common stock	(54.3)	(50.4)
Financing costs	(0.1)	(0.1)
Other	1.8	0.4
Cash Used in Financing Activities	**(111.3)**	**(47.3)**
Increase in Cash, Cash Equivalents, and Restricted Cash	**$ 0.9**	**$ 13.0**
Cash, Cash Equivalents, and Restricted Cash, beginning of period	$ 12.0	$ 9.5
Cash, Cash Equivalents, and Restricted Cash, end of period	**$ 12.9**	**$ 22.5**

Cash Provided by Operating Activities

As of June 30, 2018, cash, cash equivalents, and restricted cash were $12.9 million as compared with $12.0 million at December 31, 2017 and $22.5 million at June 30, 2017. Cash provided by operating activities totaled $247.2 million for the six months ended June 30, 2018 as compared with $179.0 million during the six months ended June 30, 2017. This increase in operating cash flows is primarily due to higher net income, improved customer receipts and recovery of certain costs through our electric and natural gas trackers, the receipt of insurance proceeds, and lower priced gas storage injections during the current period.

Cash Used in Investing Activities

Cash used in investing activities increased by approximately $16.3 million as compared with the first six months of 2017. During June 2018, we purchased the 9.7 MW Two Dot wind project in Montana for approximately $18.5 million. Other plant additions during the first six months of 2018 include maintenance additions of approximately $91.6 million and capacity related capital expenditures of approximately $24.9 million. Plant additions during the first six months of 2017 included maintenance additions of approximately $58.9 million, capacity related capital expenditures of approximately $43.7 million, and infrastructure capital expenditures of approximately $16.5 million.

Cash Used in Financing Activities

Cash used in financing activities totaled $111.3 million during the six months ended June 30, 2018 as compared with $47.3 million during the six months ended June 30, 2017. During the six months ended June 30, 2018, net cash used in financing activities reflects net repayments of commercial paper of $319.6 million and the payment of dividends of $54.3 million. These impacts were partially offset by issuances under our revolving lines of credit of $216.0 million and proceeds from the issuance of common stock of $44.9 million. During the six months ended June 30, 2017, net cash used in financing activities included the payment of dividends of $50.4 million, partially offset by net issuances of commercial paper of $2.8 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 June 30, 2018. See our Annual Report on Form 10-K for the year ended December 31, 2017 for additional discussion.

	Total	2018	2019	2020	2021	2022	Thereafter
				(in thousands)			
Long-term debt	$ 2,009,827	$ —	$ —	$ —	$ 216,000	$ —	$ 1,793,827
Capital leases	23,319	1,106	2,298	2,476	2,668	2,875	11,896
Estimated pension and other postretirement obligations (1)	59,869	11,380	12,322	12,196	12,053	11,918	N/A
Qualifying facilities liability (2)	746,760	36,965	75,278	77,319	79,166	81,060	396,972
Supply and capacity contracts (3)	2,204,487	105,692	184,600	150,763	129,806	131,912	1,501,714
Contractual interest payments on debt (4)	1,532,175	33,849	77,765	77,765	77,365	71,632	1,193,799
Environmental remediation obligations (1)	4,338	987	1,072	1,070	604	605	N/A
Total Commitments (5)	$ 6,580,775	$ 189,979	$ 353,335	$ 321,589	$ 517,662	$ 300,002	$ 4,898,208

(1) We estimate cash obligations related to our pension and other postretirement benefit programs and environmental remediation obligations 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.

(2) Certain QFs require us to purchase minimum amounts of energy at prices ranging from $74 to $136 per MWH through 2029. Our estimated gross contractual obligation related to these QFs is approximately $746.8 million. A portion of the costs incurred to purchase this energy is recoverable through rates authorized by the MPSC, totaling approximately $596.4 million.

(3) 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 27 years.

(4) Contractual interest payments includes our revolving credit facilities, which have a variable interest rate. We have assumed an average interest rate of 2.75% on the outstanding balance through maturity of the facilities.

(5) Potential tax payments related to uncertain tax positions are not practicable to estimate and have been excluded from this table.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Management's discussion and analysis of financial condition and results of operations is based on our Financial Statements, which have been prepared in accordance with GAAP. The preparation of these Financial Statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. We base our estimates on historical experience and other assumptions that are believed to be proper and reasonable under the circumstances. We continually evaluate the appropriateness of our estimates and assumptions. Actual results could differ from those estimates. We consider an estimate to be critical if it is material to the Financial Statements and it requires assumptions to be made that were uncertain at the time the estimate was made and changes in the estimate are reasonably likely to occur from period to period. This includes the accounting for the following: regulatory assets and liabilities, pension and postretirement benefit plans, and income taxes. 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, 2017. There have been no material changes in these policies except for the following:

Qualifying Facilities Liability

Our electric QF liability consists of unrecoverable costs associated with contracts covered under PURPA that are part of a 2002 stipulation with the MPSC and other parties. Under the terms of these contracts, we are required to purchase minimum amounts of energy at prices ranging from $74 to $136 per MWH through 2029. Our estimated gross contractual obligation is approximately $746.8 million through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $596.4 million through 2029. We maintain an electric QF liability based on the net present value (discounted at 7.75%) of the difference between our estimated obligations under the QFs and the fixed amounts recoverable in rates.

The liability was established based on certain assumptions and projections over the contract terms related to pricing, estimated output and recoverable amounts. Since the liability is based on projections over the next several years, actual output, changes in pricing, contract amendments and regulatory decisions relating to these facilities could significantly impact the liability and our results of operations in any given year. In assessing the liability each reporting period, we compare our assumptions to actual results and make adjustments as necessary for that period.

One of the contracts contains variable pricing terms, which exposes us to price escalation risks. The estimated annual escalation rate for this contract is a key assumption and is based on a combination of historical actual results and market data available for future projections. In recording the electric QF liability, we estimated an annual escalation rate of 3% over the remaining term of the contract (through June 2024). The actual escalation rate changes annually, which could significantly impact the liability and our results of operations.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Interest Rate Risk

Interest rate risks include exposure to adverse interest rate movements for outstanding variable rate debt and for future anticipated financings. We manage our interest rate risk by issuing primarily fixed-rate long-term debt with varying maturities, refinancing certain debt and, at times, hedging the interest rate on anticipated borrowings. All of our debt has fixed interest rates, with the exception of our revolving credit facilities. The $400 million revolving credit facility bears interest at the lower of prime plus a credit spread, ranging from 0.00% to 0.75%, or available rates tied to the Eurodollar rate plus a credit spread, ranging from 0.88% to 1.75%. 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 June 30, 2018, we had approximately $216 million in borrowings under our revolving credit facilities. A 1% increase in interest rates would increase our annual interest expense by approximately $2.2 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 and cost, 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 cost tracking mechanisms and are recoverable from customers subject to prudence reviews by applicable state regulatory commissions.

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 12, Commitments and Contingencies, to the Financial Statements for information regarding legal proceedings.

ITEM 1A. RISK FACTORS -

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

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

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

While rate regulation is premised on providing a reasonable opportunity to earn a reasonable rate of return on invested capital, there can be no assurance that the applicable regulatory commission will judge all of our costs to have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of such costs. In addition to rate cases, our cost tracking mechanisms are a significant component of how we recover our costs. Historically, our wholesale costs for electricity and natural gas supply were recovered through various pass-through cost tracking mechanisms in each of the states we serve.

Montana

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

- In 2018, the MPSC issued an order in our 2017 property tax tracker filing reducing our recovery of Montana property taxes between general rate filings by applying an alternate allocation methodology. This results in a lower property tax allocation to our Montana electric retail customers and a higher property tax allocation to FERC transmission customers (we do not have a property tax tracker for FERC jurisdictional purposes).

- In 2017, the MPSC revised our QF tariff for standard QF rates for small QFs (3 MW or less) to establish a maximum contract length of 15 years and a substantially lower rate for future QF contracts. In this order, the MPSC also applied the 15-year contract term to our future owned and contracted electric supply resources. As a result, we terminated our competitive solicitation process to determine the lowest-cost / least-risk approach for addressing our intermittent capacity and reserve margin needs in Montana. This order may have a significant impact on our approach to meet our portfolio needs.

- In 2016, the MPSC disallowed replacement power costs from a 2013 outage at Colstrip Unit 4 requested in our electric tracker filings. We appealed the MPSC's decision regarding the disallowance of Colstrip Unit 4 costs in Montana District Court, arguing that these decisions were arbitrary and capricious, and violated Montana law.

- In 2015, the MPSC issued an order eliminating the lost revenue adjustment mechanism. This mechanism was established in 2005 as a component of an approved energy efficiency program, by which we recovered on an after-the-fact basis our fixed costs that would otherwise have been collected in the kilowatt hour sales lost due to energy efficiency programs through our supply tracker. Recovery of lost revenues was terminated, prospectively, effective December 1, 2015.

- In 2013, the MPSC concluded that costs associated with a 2012 outage at DGGS were imprudently incurred, and disallowed recovery.

We have two significant dockets currently in process with the MPSC, including revisions to our statutory electric supply tracker and the adjustment of rates due the Tax Cuts and Jobs Act. Regarding the electric supply tracker, the MPSC advocated before the 2017 Montana Legislature for a revision to the statute that provided for mandatory recovery of our prudently incurred electric supply costs, and in April 2017, the Montana legislature passed HB 193, amending the statute. The revised statute gives the MPSC discretion whether to approve an electric supply cost adjustment mechanism. In July 2017, we filed a proposed electric PCCAM. Following the submission of intervenor testimony, the MPSC identified additional issues. The MPSC held a hearing during the second quarter of 2018. We cannot guarantee how the MPSC may apply the statute in establishing a revised mechanism. To the extent our energy supply costs are deemed imprudent by the MPSC, or the passage of HB 193 reduces our recovery or the timeliness of cash flows, the revised mechanism could adversely impact our results of operations and cash flows.

We also submitted a filing in March 2018 regarding the customer benefit of the Tax Cuts and Jobs Act, calculated using two alternative methods. We cannot predict how the MPSC may address this filing. If the MPSC determines the credits due to customers are higher than the expected reduction to income tax expense, this would result in an adverse impact to results of operations and cash flows.

FERC & Other Regulation

We must comply with established reliability standards and requirements including Critical Infrastructure Protection (CIP) Reliability Standards, which apply to the North American Electric Reliability Corporation (NERC) functions in both the Midwest Reliability Organization for our South Dakota operations and Western Electricity Coordination Council for our Montana operations. The FERC, NERC, or a regional reliability organization may assess penalties against any responsible entity that violates their rules, regulations or standards. Violations may be discovered through various means, including self-certification, self-reporting, compliance investigations, audits, periodic data submissions, exception reporting, and complaints. 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.

We are also 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 existing, and potential future, federal and state legislation. In the planning and management of our operations, we must address the effects of legislation within a regulatory framework. Federal and state laws can significantly impact our operations, whether it is new or revised statutes directly affecting the electric and gas industry, or other issues such as taxes.

In addition, new or revised statutes can also materially affect our operations through impacting existing regulations or requiring new regulations. These changes are ongoing, and we cannot predict the future course of changes or the ultimate effect that this changing environment will have on us. Changes in laws, and the resulting regulations and tariffs and how they are implemented and interpreted, may have a material adverse effect on our financial condition, results of operations and cash flows.

Our ability to invest in additional generation is impacted by PURPA, which requires electric utilities, with certain exceptions, to purchase energy and capacity from independent power producers that are QFs. Our 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.

On June 22, 2016, the Securing America’s Future Energy: Protecting our Infrastructure of Pipelines and Enhancing Safety Act (SAFE PIPES Act), was signed into law. The law prioritized the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) completion of outstanding regulations and proposed regulations to safety standards for natural gas transmission and gathering pipelines. The long-anticipated proposal could impose significant regulatory requirements for additional miles of natural gas pipeline, including pipelines constructed prior to 1970, which were previously exempt from PHMSA regulations related to pressure testing. It would also create a new "Moderate Consequence Area" category to expand safety protocols to pipelines in moderately populated areas. The rule also would codify the Integrity Verification Process (IVP) which is a process that will require companies to have reliable, traceable, verifiable, and complete records for pipelines in certain areas. The rule would establish a deadline for IVP completion that we will be required to meet. Costs incurred to comply with the proposed regulations may be material.

Federally mandated purchases of power from QFs, and integration of power generated from those projects in our system, may increase costs and decrease system reliability, 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 that 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, which could increase costs to customers. In addition, this may impact our ability to invest in additional generation. Further, balancing load and generation from power generation on our system is challenging, and we expect that operational costs will increase as a result of integration of these intermittent, non-dispatchable generation projects. If we are unable to timely recover those costs through our power cost adjustment mechanism or otherwise, those increased costs may negatively affect our liquidity, results of operations, financial condition, and investment plans.

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

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

In October 2015, the EPA published standards for states to implement to control GHG emissions from existing electric generating units. These standards are referred to as the CPP. We, along with a number of states and other parties, filed lawsuits against the EPA standards. The EPA proposed to repeal the CPP in October 2017, and in December 2017, issued an Advance Notice of Proposed Rulemaking (ANPR), soliciting information on systems of emission reduction that comply with EPA's interpretation of the Clean Air Act, for a possible replacement of the CPP. Most recently, on July 9, 2018, the EPA forwarded its proposed rule replacing the CPP to the OMB for interagency review. In light of these administrative actions, the future of the CPP regulations and associated guidance is uncertain. However, if the CPP is not repealed, survives the pending legal challenges and is implemented as written or if a replacement to the CPP is adopted with similar requirements, it could result in significant additional compliance costs that would affect our future results of operations and financial position if such costs are not recovered through regulated rates. Due to the pending litigation, the proposed repeal of the CPP, the ANPR, and the uncertainties in the state approaches, the ultimate timing and impact of the CPP or other GHG regulations on our operations cannot be determined with certainty at this time. Complying with the CO_2 emission performance standards, and with other future environmental rules, may make it economically impractical to continue operating all or a portion of our jointly owned facilities or for individual owners to participate in their proportionate ownership of the coal-fired generating units. This could lead to significant impacts to customer rates for recovery of plant improvements and / or closure related costs and costs to procure replacement power. In addition, these changes could impact system reliability due to changes in generation sources.

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

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

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

Inherent in our electric and natural gas operations are a variety of hazards and operating risks, such as fires, electric contacts, leaks, explosions, catastrophic failures and mechanical problems. These risks could cause a loss of human life, significant damage to property, loss of customer load, environmental pollution, impairment of our operations, and substantial financial losses to us and others. Fires alleged to have been caused by our system could also expose us to significant damage claims on theories such as strict liability, negligence, gross negligence, trespass, inverse condemnation, and others. The risk of wildfires is exacerbated in forested areas where beetle infestations have caused a significant increase in the quantity of standing dead and dying timber, increasing the risk that such trees may fall from either inside or outside our right-of-way into a powerline igniting a fire. 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 damages resulting from these risks are significant. In accordance with customary industry practice, 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.

Our owned and jointly owned electric generating facilities are subject to risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses, increased power purchase costs and the inability to recover our investment.

Operation of electric generating facilities involves risks, which can adversely affect energy output and efficiency levels. Operational risks include facility shutdowns due to breakdown or failure of equipment or processes, 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. In early July 2013, following the return to service from a scheduled maintenance outage, Colstrip Unit 4 tripped off-line and incurred damage to its stator and rotor. Colstrip Unit 4 returned to service in early 2014. As discussed above, we were not able to fully recover our costs for the purchase of replacement power while Colstrip Unit 4 was out of service.

Our investment in generating facilities is a long-lived asset. An early retirement of a unit before the end of the current estimated useful life or change in classification as held for use could have a material adverse impact on our results of operations. The timing of a change in estimated useful life may be dependent upon events out of our control. The costs associated with a retirement, which may include, among other things, accelerated depreciation and amortization or impairment charges, accelerated asset retirement costs, severance costs and environmental remediation costs, could be material and we have no assurance of recovery of these costs from customers.

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. We do not have ownership in Units 1 and 2, and decisions regarding these units, including their shut down, were made by their respective owners. The six owners of Colstrip currently share the operating costs pursuant to the terms of an operating agreement among the owners of Units 3 and 4 and a common facilities agreement among the owners of all four units. When Units 1 and 2 discontinue operation, we anticipate incurring incremental operating costs with respect to our interest in Unit 4 and expect to experience a negative impact on our transmission revenue due to reduced amounts of energy transmitted across our transmission lines. This reduction would be incorporated in our next general electric rate filing after the closure of Units 1 and 2, resulting in lower revenue credits to certain customers. In addition, the remaining depreciable life of our investment in Colstrip Unit 4 is through 2042. Two of the other joint owners have entered into settlements with regulators to accelerate the recovery of their investment in Colstrip Units 3 and 4 by using a depreciable life through 2027, but have not established a date for closure. Recovery of costs associated with the shut-down of the facility prior to the end of the useful life would be subject to MPSC approval.

Colstrip Units 3 and 4 are supplied with fuel from adjacent coal reserves under coal supply and transportation agreements in effect through 2019. We and other joint owners are discussing new coal supply and transportation agreements, which anticipate expansion of the coal mine. This expansion requires environmental reviews and permitting. We cannot predict when or if those permits will be granted. Our coal supply and transportation agreements are with Western Energy Company (WeCo), a subsidiary of Westmoreland Coal Co. (Westmoreland), which notified its investors that it may seek Chapter 11 reorganization. While we cannot predict the ultimate effect of a Westmoreland or WeCo bankruptcy, we do not expect our existing coal supply and transportation agreements to be adversely affected and will continue negotiations for new agreements. If a new coal supply contract is not in place, we could continue under the current arrangement under mutual agreement, however the extraction costs would increase.

We also rely on a limited number of suppliers of coal for our electric generation, making us vulnerable to increased prices for fuel as existing contracts expire or in the event of unanticipated interruptions in fuel supply. We are a captive rail shipper of the Burlington Northern Santa Fe Railway for shipments of coal to the Big Stone Plant (our largest source of generation in South Dakota), making us vulnerable to railroad capacity and operational issues and/or increased prices for coal transportation from a sole supplier.

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, thunderstorms, high winds, microbursts, wildfires, 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 wildfires, which could threaten our communities and electric distribution and transmission lines and facilities. In addition, wildfires 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 wildfires could negatively impact our financial condition, results of operations or cash flows.

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

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

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

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.

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) and physical security breaches and other disruptive activities of individuals or groups. Our generation, transmission and distribution facilities are deemed critical infrastructure and provide the framework for our service infrastructure. These 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 cyber attacks and other disruptive activities on third party facilities that are interconnected to us through the regional transmission grid or natural gas pipeline infrastructure.

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.

We rely on information technology networks and systems to operate our critical infrastructure, engage in asset management activities, and process, transmit and store electronic information including customer and employee information. Further, our infrastructure, networks and systems are interconnected to external networks and neighboring critical infrastructure systems. Security breaches could lead to system disruptions, generating facility shutdowns or unauthorized disclosure of confidential information. Cyber or physical attacks, terrorist acts, or disruptive activities could harm our business by limiting our ability to generate, purchase or transmit power and by delaying the development and construction of new facilities and capital improvements to existing facilities.

In addition, our information systems and those of our third-party vendors contain confidential information, including information about customers and employees. 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.

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.

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, both 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 and the availability of generation, among other factors. Declines in wholesale market price, availability of generation, transmission constraints in the wholesale markets, or low wholesale demand could reduce wholesale sales. These events could adversely affect our results of operations, financial position and cash flows.

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

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

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

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

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

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

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

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

ITEM 6. EXHIBITS -

(a) Exhibits

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

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

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

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

Exhibit 101.INS—XBRL Instance Document

Exhibit 101.SCH—XBRL Taxonomy Extension Schema Document

Exhibit 101.CAL—XBRL Taxonomy Extension Calculation Linkbase Document

Exhibit 101.DEF—XBRL Taxonomy Extension Definition Linkbase Document

Exhibit 101.LAB—XBRL Taxonomy Label Linkbase Document

Exhibit 101.PRE—XBRL Taxonomy Extension Presentation Linkbase Document

SIGNATURES

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

		NorthWestern Corporation
Date: July 20, 2018	By:	/s/ BRIAN B. BIRD
		Brian B. Bird
		Chief Financial Officer
		Duly Authorized Officer and Principal Financial Officer