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

FORM 10-Q

(mark one)

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

For the quarterly period ended September 30, 2022

OR

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

For the transition period from to

Commission File Number: 1-10499

NORTHWESTERN CORP

(Exact name of registrant as specified in its charter)

Delaware	**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

N/A

(Former name, former address and former fiscal year, if changed since last report)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common stock	NWE	Nasdaq Stock Market LLC

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

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

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

Large Accelerated Filer ☒ Accelerated Filer ☐ Non-accelerated Filer ☐ Smaller Reporting Company ☐ Emerging Growth Company ☐

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

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

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

Common Stock, Par Value $0.01, 57,778,743 shares outstanding at October 21, 2022

NORTHWESTERN CORPORATION

FORM 10-Q

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

On one or more occasions, we may make statements in this Quarterly Report on Form 10-Q regarding our assumptions, projections, expectations, targets, intentions or beliefs about future events. All statements other than statements of historical facts, included or incorporated by reference in this Quarterly Report, relating to our 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, our examination of historical operating trends, data contained in records and other data available from third parties, we cannot assure you that we will achieve our projections. Factors that may cause such differences include, but are not limited to:

- adverse determinations by regulators, as well as potential adverse federal, state, or local legislation or regulation, including costs of compliance with existing and future environmental requirements, could have a material effect on our liquidity, results of operations and financial condition;
- the impact of extraordinary external events and natural disasters, such as the COVID-19 pandemic, geopolitical events, earthquake, flood, drought, lightning, weather, wind, and fire, could have a material effect on our liquidity, results of operations and financial condition;
- acts of terrorism, cybersecurity attacks, data security breaches, or other malicious acts that cause damage to our generation, transmission, or distribution facilities, information technology systems, or result in the release of confidential customer, employee, or Company information;
- supply chain constraints, recent high levels of inflation for product, services and labor costs, and their impact on capital expenditures, operating activities, and/or our ability to safely and reliably serve our customers;
- 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 operating costs or may require additional capital expenditures or other increased operating costs; and
- adverse changes in general economic and competitive conditions in the U.S. financial markets and in our service territories.

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

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

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

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

PART 1. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

NORTHWESTERN CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(Unaudited)

(in thousands, except per share amounts)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
Revenues				
Electric	$ 292,270	$ 287,473	$ 807,415	$ 798,984
Gas	42,798	38,482	245,139	225,991
Total Revenues	335,068	325,955	1,052,554	1,024,975
Operating expenses				
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	108,920	98,659	338,994	311,137
Operating and maintenance	54,654	56,002	160,785	159,317
Administrative and general	28,146	24,946	87,010	79,596
Property and other taxes	46,466	43,572	140,209	138,337
Depreciation and depletion	48,588	47,112	145,705	140,896
Total Operating Expenses	286,774	270,291	872,703	829,283
Operating income	48,294	55,664	179,851	195,692
Interest expense, net	(25,332)	(23,283)	(73,081)	(70,266)
Other income, net	4,157	5,326	11,791	13,932
Income before income taxes	27,119	37,707	118,561	139,358
Income tax benefit (expense)	249	(2,511)	(2,297)	(3,854)
Net Income	$ 27,368	$ 35,196	$ 116,264	$ 135,504
Average Common Shares Outstanding	56,311	51,892	54,901	51,175
Basic Earnings per Average Common Share	$ 0.48	$ 0.68	$ 2.12	$ 2.65
Diluted Earnings per Average Common Share	$ 0.47	$ 0.68	$ 2.09	$ 2.64
Dividends Declared per Common Share	$ 0.63	$ 0.62	$ 1.89	$ 1.86

See Notes to Condensed Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)

(in thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	**2021**	**2022**	**2021**
Net Income	$ 27,368	$ 35,196	$ 116,264	$ 135,504
Other comprehensive income, net of tax:				
Foreign currency translation adjustment	(4)	(1)	(5)	(56)
Postretirement medical liability adjustment	(158)	(159)	(474)	(476)
Reclassification of net losses on derivative instruments	113	113	339	339
Total Other Comprehensive Loss	(49)	(47)	(140)	(193)
Comprehensive Income	$ 27,319	$ 35,149	$ 116,124	$ 135,311

See Notes to Condensed Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

(in thousands, except share data)

	September 30, 2022	December 31, 2021
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 9,069	$ 2,820
Restricted cash	19,656	15,942
Accounts receivable, net	149,149	198,671
Inventories	129,254	80,614
Regulatory assets	136,329	115,541
Prepaid expenses and other	29,346	24,207
Total current assets	**472,803**	**437,795**
Property, plant, and equipment, net	5,533,601	5,247,232
Goodwill	357,586	357,586
Regulatory assets	701,771	690,686
Other noncurrent assets	48,452	47,144
Total Assets	**$ 7,114,213**	**$ 6,780,443**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current maturities of finance leases	$ 3,040	$ 2,875
Current portion of long-term debt	144,467	—
Accounts payable	148,451	115,237
Accrued expenses and other	300,702	233,351
Regulatory liabilities	21,781	28,179
Total current liabilities	**618,441**	**379,642**
Long-term finance leases	9,602	11,897
Long-term debt	2,409,002	2,541,478
Deferred income taxes	518,076	499,634
Noncurrent regulatory liabilities	656,467	638,760
Other noncurrent liabilities	365,296	369,319
Total Liabilities	**4,576,884**	**4,440,730**
Commitments and Contingencies (Note 10)		
Shareholders' Equity:		
Common stock, par value $0.01; authorized 200,000,000 shares; issued and outstanding 61,317,609 and 57,776,740 shares, respectively; Preferred stock, par value $0.01; authorized 50,000,000 shares; none issued	613	576
Treasury stock at cost	(98,578)	(98,248)
Paid-in capital	1,900,992	1,716,227
Retained earnings	741,752	728,468
Accumulated other comprehensive loss	(7,450)	(7,310)
Total Shareholders' Equity	**2,537,329**	**2,339,713**
Total Liabilities and Shareholders' Equity	**$ 7,114,213**	**$ 6,780,443**

See Notes to Condensed Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(in thousands)

	Nine Months Ended September 30,	
	2022	2021
OPERATING ACTIVITIES:		
Net income	$ 116,264	$ 135,504
Items not affecting cash:		
Depreciation and depletion	145,705	140,896
Amortization of debt issuance costs, discount and deferred hedge gain	4,044	3,951
Stock-based compensation costs	4,324	5,850
Equity portion of allowance for funds used during construction	(9,983)	(7,829)
Loss on disposition of assets	524	6,536
Deferred income taxes	(12,127)	(681)
Changes in current assets and liabilities:		
Accounts receivable	49,522	28,901
Inventories	(48,639)	(23,400)
Other current assets	(5,139)	(8,442)
Accounts payable	36,064	(12,472)
Accrued expenses and other	67,636	85,015
Regulatory assets	(20,788)	(67,672)
Regulatory liabilities	(6,398)	(32,941)
Other noncurrent assets	8,968	610
Other noncurrent liabilities	(20,707)	(32,216)
Cash Provided by Operating Activities	**309,270**	**221,610**
INVESTING ACTIVITIES:		
Property, plant, and equipment additions	(386,339)	(311,160)
Investment in equity securities	(914)	(655)
Cash Used in Investing Activities	**(387,253)**	**(311,815)**
FINANCING ACTIVITIES:		
Proceeds from issuance of common stock, net of issuance costs	179,903	121,066
Dividends on common stock	(102,980)	(95,148)
Issuance of long-term debt, net	—	99,915
Line of credit borrowings, net	12,000	73,000
Repayments on long-term debt	—	(955)
Repayments of short-term borrowings	—	(100,000)
Other financing activities, net	(977)	(550)
Cash Provided by Financing Activities	**87,946**	**97,328**
Increase in Cash, Cash Equivalents, and Restricted Cash	9,963	7,123
Cash, Cash Equivalents, and Restricted Cash, beginning of period	18,762	17,096
Cash, Cash Equivalents, and Restricted Cash, end of period	**$ 28,725**	**$ 24,219**
Supplemental Cash Flow Information:		
Cash paid during the period for:		
Income taxes	$ 9,060	$ 3,630
Interest	60,610	57,473
Significant non-cash transactions:		
Capital expenditures included in accounts payable	26,184	23,500

See Notes to Condensed Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(Unaudited)

(in thousands, except per share data)

	Three Months Ended September 30,							
	Number of Common Shares	Number of Treasury Shares	Common Stock	Treasury Stock	Paid in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Shareholders' Equity
Balance at June 30, 2021	**55,118**	**3,558**	**$ 551**	**$ (98,578)**	**$1,575,159**	**$707,598**	**$ (7,415)**	**$ 2,177,315**
Net income	—	—	—	—	—	35,196	—	35,196
Foreign currency translation adjustment, net of tax	—	—	—	—	—	—	(1)	(1)
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	113	113
Postretirement medical liability adjustment, net of tax	—	—	—	—	—	—	(159)	(159)
Stock-based compensation	—	—	—	—	1,301	—	—	1,301
Issuance of shares	1,039	(6)	11	154	64,930	—	—	65,095
Dividends on common stock ($0.620 per share)	—	—	—	—	—	(32,327)	—	(32,327)
Balance at September 30, 2021	**56,157**	**3,552**	**$ 562**	**$ (98,424)**	**$1,641,390**	**$710,467**	**$ (7,462)**	**$ 2,246,533**
Balance at June 30, 2022	**59,697**	**3,548**	**$ 597**	**$ (98,765)**	**$1,820,531**	**$749,558**	**$ (7,401)**	**$ 2,464,520**
Net income	—	—	—	—	—	27,368	—	27,368
Foreign currency translation adjustment, net of tax	—	—	—	—	—	—	(4)	(4)
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	113	113
Postretirement medical liability adjustment, net of tax	—	—	—	—	—	—	(158)	(158)
Stock-based compensation	—	—	—	—	2,080	—	—	2,080
Issuance of shares	1,621	(7)	16	187	78,381	—	—	78,584
Dividends on common stock ($0.630 per share)	—	—	—	—	—	(35,174)	—	(35,174)
Balance at September 30, 2022	**61,318**	**3,541**	**$ 613**	**$ (98,578)**	**$1,900,992**	**$741,752**	**$ (7,450)**	**$ 2,537,329**

	Nine Months Ended September 30,							
	Number of Common Shares	Number of Treasury Shares	Common Stock	Treasury Stock	Paid in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Shareholders' Equity
Balance at December 31, 2020	**54,145**	**3,558**	**$ 541**	**$ (98,075)**	**$ 1,513,787**	**$ 670,111**	**$ (7,269)**	**$ 2,079,095**
Net income	—	—	—	—	—	135,504	—	135,504
Foreign currency translation adjustment, net of tax	—	—	—	—	—	—	(56)	(56)
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	339	339
Postretirement medical liability adjustment, net of tax	—	—	—	—	—	—	(476)	(476)
Stock-based compensation	93	17	1	(970)	5,811	—	—	4,842
Issuance of shares	1,919	(23)	20	621	121,792	—	—	122,433
Dividends on common stock ($1.860 per share)	—	—	—	—	—	(95,148)	—	(95,148)
Balance at September 30, 2021	**56,157**	**3,552**	**$ 562**	**$ (98,424)**	**$ 1,641,390**	**$ 710,467**	**$ (7,462)**	**$ 2,246,533**
Balance at December 31, 2021	**57,606**	**3,546**	**$ 576**	**$ (98,248)**	**$ 1,716,227**	**$ 728,468**	**$ (7,310)**	**$ 2,339,713**
Net income	—	—	—	—	—	116,264	—	116,264
Foreign currency translation adjustment, net of tax	—	—	—	—	—	—	(5)	(5)
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	339	339
Postretirement medical liability adjustment, net of tax	—	—	—	—	—	—	(474)	(474)
Stock-based compensation	87	16	1	(911)	6,056	—	—	5,146
Issuance of shares	3,625	(21)	36	581	178,709	—	—	179,326
Dividends on common stock ($1.890 per share)	—	—	—	—	—	(102,980)	—	(102,980)
Balance at September 30, 2022	**61,318**	**3,541**	**$ 613**	**$ (98,578)**	**$ 1,900,992**	**$ 741,752**	**$ (7,450)**	**$ 2,537,329**

See Notes to Condensed Consolidated Financial Statements

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Reference is made to Notes to Financial Statements included in NorthWestern Corporation's Annual Report)
(Unaudited)

(1) Nature of Operations and Basis of Consolidation

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and/or natural gas to approximately 753,600 customers in Montana, South Dakota, Nebraska and Yellowstone National Park.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires us 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 our opinion, necessary to fairly present our financial position, results of operations and cash flows. The actual results for the interim periods are not necessarily indicative of the operating results to be expected for a full year or for other interim periods. Events occurring subsequent to September 30, 2022 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, we believe that the condensed disclosures provided are adequate to make the information presented not misleading. We recommend that these Financial Statements be read in conjunction with the audited financial statements and related footnotes included in our Annual Report on Form 10-K for the year ended December 31, 2021.

Reclassification

In 2021, we renamed the line item "Cost of sales" as previously shown on the Consolidated Statements of Income, and used elsewhere within our filing, to "Fuel, purchased supply and direct transmission expense." Additionally, we disaggregated the line item "Operating, general and administrative" as previously shown on the Consolidated Statements of Income, and used elsewhere within our filing, to two line items, "Operating and maintenance" and "Administrative and general." These reclassifications were done in an effort to better convey the nature of these costs and did not impact reported operating income or net income.

Supplemental Cash Flow Information

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

	September 30, 2022	December 31, 2021	September 30, 2021	December 31, 2020
Cash and cash equivalents	$ 9,069	$ 2,820	$ 8,577	$ 5,811
Restricted cash	19,656	15,942	15,642	11,285
Total cash, cash equivalents, and restricted cash shown in the Condensed Consolidated Statements of Cash Flows	$ 28,725	$ 18,762	$ 24,219	$ 17,096

Goodwill

We completed our annual goodwill impairment test as of April 1, 2022 and no impairment was identified. We calculate the fair value of our reporting units by considering various factors, including valuation studies based primarily on a discounted cash flow analysis, with published industry valuations and market data as supporting information. Key assumptions in the determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate expected long-term growth rates in our service territory, regulatory stability, and commodity prices (where appropriate), as well as other factors that affect our revenue, expense and capital expenditure projections.

(2) Regulatory Matters

Montana Rate Review

On August 8, 2022, we filed a Montana electric and natural gas rate review with the Montana Public Service Commission (MPSC) requesting an annual increase to electric and natural gas utility rates of $171.0 million and $23.0 million, respectively, detailed as follows:

Requested Revenue Increase (in millions)

	Electric	Natural Gas
Base Rates	$91.8	$20.2
Power Cost & Credit Mechanism (PCCAM)(1)	$68.1	n/a
Property Tax (tracker true-up)(1)	$11.1	$2.8
Total	$171.0	$23.0

(1) These items are flow-through costs, which represent approximately 42% of the requested electric and natural gas revenue increase.

Our electric request is based on a return on equity of 10.60% with a forecasted 2022 rate base of $2.8 billion and a capital structure of 51.98% debt and 48.02% equity. Our natural gas request is based on a return on equity of 10.60% with a forecasted 2022 rate base of $575.3 million and a capital structure of 51.98% debt and 48.02% equity.

Within this rate review filing we requested an increase to the Power Cost and Credit Mechanism (PCCAM) base rate (PCCAM Base) of $68.1 million, as well as structural revisions to the PCCAM mechanism to provide customers with prices that better reflect the cost of services received. We also proposed to implement a revised electric only pilot for the Fixed Cost Recovery Mechanism (FCRM) beginning July 1, 2023, or alternatively to terminate the FCRM. Our rate review filing also includes proposals for more timely cost recovery beyond the test period, including critical reliability resources, such as the Yellowstone Generating Station, our Enhanced Wildfire Mitigation plan, and business technology maintenance costs.

On September 28, 2022, the MPSC approved the recommendations of the MPSC Staff for interim rates, subject to refund, which increased base electric rates $29.4 million, PCCAM Base rates $61.1 million, and base natural gas rates $1.7 million, effective October 1, 2022.

Montana Community Renewable Energy Projects (CREPs)

As further discussed in Note 3 - "Regulatory Matters" of our Annual Report on Form 10-K for the year ended December 31, 2021, we have been involved in litigation associated with our past progress towards meeting obligations to acquire renewable energy projects, as mandated by the recently repealed Montana CREP requirement. Although we had been granted waivers by the MPSC and the CREP requirement was subsequently repealed by the Montana legislature, on May 9, 2022, the Montana District Court imposed a $2.5 million penalty against us, payable to the Universal Low Income Assistance Fund in Montana, in connection with the petition filed by the Montana Environmental Information Center (MEIC) challenging the MPSC's decision granting our waiver requests from CREP compliance in 2015 and 2016. The expense associated with this penalty was accrued for within our second quarter 2022 results. We filed an appeal with the Montana Supreme Court.

Federal Energy Regulatory Commission (FERC) Financial Audit

We are subject to FERC’s jurisdiction and regulations with respect to rates for electric transmission service in interstate commerce and electricity sold at wholesale rates, the issuance of certain securities, and incurrence of certain long-term debt, among other things. The Division of Audits and Accounting in the Office of Enforcement of FERC initiated a routine audit of NorthWestern Corporation for the period of January 1, 2018 to October 31, 2021 to evaluate our compliance with FERC accounting and financial reporting requirements. In May 2022, we received the final audit report from FERC and the resolution of the identified audit findings and recommendations did not have a material financial impact on our Financial Statements.

(3) Income Taxes

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

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

	Three Months Ended September 30,			
	2022		2021	
Income before income taxes	$ 27,119		$ 37,707	
Income tax calculated at federal statutory rate	5,697	21.0 %	7,918	21.0 %
Permanent or flow-through adjustments:				
State income tax, net of federal provisions	145	0.5	397	1.1
Flow-through repairs deductions	(3,374)	(12.4)	(3,473)	(9.2)
Production tax credits	(1,668)	(6.2)	(1,877)	(5.0)
Income tax return to accrual adjustment	(926)	(3.4)	389	1.0
Amortization of excess deferred income tax	(246)	(0.9)	(126)	(0.3)
Share-based compensation	—	—	(62)	(0.2)
Plant and depreciation of flow-through items	266	1.0	(288)	(0.8)
Other, net	(143)	(0.5)	(367)	(1.0)
	(5,946)	(21.9)	(5,407)	(14.4)
Income tax (benefit) expense	$ (249)	(0.9)%	$ 2,511	6.6 %

	Nine Months Ended September 30,			
	2022		2021	
Income before income taxes	$ 118,561		$ 139,358	
Income tax calculated at federal statutory rate	24,897	21.0 %	29,265	21.0 %
Permanent or flow through adjustments:				
State income, net of federal provisions	976	0.8	674	0.5
Flow-through repairs deductions	(13,488)	(11.4)	(15,553)	(11.2)
Production tax credits	(8,050)	(6.8)	(8,446)	(6.1)
Income tax return to accrual adjustment	(926)	(0.8)	389	0.3
Amortization of excess deferred income tax	(819)	(0.7)	(534)	(0.4)
Share-based compensation	(253)	(0.2)	(323)	(0.2)
Plant and depreciation of flow through items	409	0.3	(812)	(0.6)
Other, net	(449)	(0.3)	(806)	(0.5)
	(22,600)	(19.1)	(25,411)	(18.2)
Income tax expense	$ 2,297	1.9 %	$ 3,854	2.8 %

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 had unrecognized tax benefits of approximately $30.8 million as of September 30, 2022, including approximately $28.0 million that, if recognized, would impact our effective tax rate. We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statutes of limitation within the next twelve months.

Our policy is to recognize interest and penalties related to uncertain tax positions in income tax expense. As of September 30, 2022, we have accrued $1.1 million for the payment of interest and penalties on the Condensed Consolidated Balance Sheets. As of December 31, 2021, we had accrued $0.5 million for the payment of interest and penalties on the Condensed Consolidated Balance Sheets.

Tax years 2018 and forward remain subject to examination by the Internal Revenue Service and state taxing authorities.

(4) Comprehensive (Loss) Income

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

	Three Months Ended					
	September 30, 2022			September 30, 2021		
	Before-Tax Amount	Tax Expense	Net-of-Tax Amount	Before-Tax Amount	Tax Expense	Net-of-Tax Amount
Foreign currency translation adjustment	$ (4)	$ —	$ (4)	$ (1)	$ —	$ (1)
Reclassification of net income on derivative instruments	153	(40)	113	153	(40)	113
Postretirement medical liability adjustment	(212)	54	(158)	(212)	53	(159)
Other comprehensive (loss) income	$ (63)	$ 14	$ (49)	$ (60)	$ 13	$ (47)

	Nine Months Ended					
	September 30, 2022			September 30, 2021		
	Before-Tax Amount	Tax Expense	Net-of-Tax Amount	Before-Tax Amount	Tax Expense	Net-of-Tax Amount
Foreign currency translation adjustment	$ (5)	$ —	$ (5)	$ (56)	$ —	$ (56)
Reclassification of net income on derivative instruments	459	(120)	339	459	(120)	339
Postretirement medical liability adjustment	(636)	162	(474)	(636)	160	(476)
Other comprehensive (loss) income	$ (182)	$ 42	$ (140)	$ (233)	$ 40	$ (193)

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

	September 30, 2022	December 31, 2021
Foreign currency translation	$ 1,438	$ 1,443
Derivative instruments designated as cash flow hedges	(9,938)	(10,277)
Postretirement medical plans	1,050	1,524
Accumulated other comprehensive loss	$ (7,450)	$ (7,310)

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

		Three Months Ended September 30, 2022			
	Affected Line Item in the Condensed Consolidated Statements of Income	Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (10,051)	$ 1,208	$ 1,442	$ (7,401)
Other comprehensive income before reclassifications		—	—	(4)	(4)
Amounts reclassified from AOCL	Interest Expense	113	—	—	113
Amounts reclassified from AOCL		—	(158)	—	(158)
Net current-period other comprehensive income (loss)		113	(158)	(4)	(49)
Ending balance		$ (9,938)	$ 1,050	$ 1,438	$ (7,450)

		Three Months Ended September 30, 2021			
	Affected Line Item in the Condensed Consolidated Statements of Income	Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (10,503)	$ 1,643	$ 1,445	$ (7,415)
Other comprehensive income before reclassifications		—	—	(1)	(1)
Amounts reclassified from AOCL	Interest Expense	113	—	—	113
Amounts reclassified from AOCL		—	(159)	—	(159)
Net current-period other comprehensive income (loss)		113	(159)	(1)	(47)
Ending balance		$ (10,390)	$ 1,484	$ 1,444	$ (7,462)

	Affected Line Item in the Condensed Consolidated Statements of Income	Nine Months Ended September 30, 2022			
		Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Pension and Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (10,277)	$ 1,524	$ 1,443	$ (7,310)
Other comprehensive loss before reclassifications		—	—	(5)	(5)
Amounts reclassified from AOCL	Interest Expense	339	—	—	339
Amounts reclassified from AOCL		—	(474)	—	(474)
Net current-period other comprehensive income (loss)		339	(474)	(5)	(140)
Ending balance		$ (9,938)	$ 1,050	$ 1,438	$ (7,450)

	Affected Line Item in the Condensed Consolidated Statements of Income	Nine Months Ended September 30, 2021			
		Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Pension and Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (10,729)	$ 1,960	$ 1,500	$ (7,269)
Other comprehensive loss before reclassifications		—	—	(56)	(56)
Amounts reclassified from AOCL	Interest Expense	339	—	—	339
Amounts reclassified from AOCL		—	(476)	—	(476)
Net current-period other comprehensive income (loss)		339	(476)	(56)	(193)
Ending balance		$ (10,390)	$ 1,484	$ 1,444	$ (7,462)

(5) Financing Activities

On November 17, 2021, we announced a registered public offering of 6,074,767 shares of our common stock at a public offering price of $53.50 per share, for an issuance amount of $325.0 million. In conjunction with this offering, we granted the underwriters an option to purchase up to 911,215 additional shares, which was subsequently exercised in full, for an additional issuance amount of $48.8 million. Of the total 6,985,982 shares of common stock offered, we initially sold 1,401,869 shares, for $75.0 million in gross proceeds, directly to the underwriters in the offering, with cash proceeds received at closing. The remaining 5,584,113 shares were sold under forward sales agreements which provide for settlement on a settlement date or dates to be specified at our discretion, but which is expected to occur on or prior to February 28, 2023. The cumulative shares issued under the forward sales agreement is limited to one and one-half times the base number of shares within the agreement, or 8,376,170 shares.

The forward sales agreements will be physically settled with common shares issued by us, unless we elect to settle the agreements in cash or to net share settle the agreements, subject to certain conditions. On a settlement date or dates, if we decide to physically settle the forward sales agreement, we will issue shares of common stock to the forward purchaser at the then-applicable forward sale price and receive issuance proceeds at that time. The forward sale price will initially be $51.8950 per share, which is subject to adjustment based on a floating interest rate factor equal to the overnight bank funding rate less a spread of 75.00 basis points, and will be subject to decrease on certain dates specified in the forward sale agreement by amounts related to expected dividends on shares of common stock during the term of the forward sale agreement.

On June 24, 2022, we partially settled the forward sale agreement by physically delivering 2,004,483 shares of common stock in exchange for cash proceeds of $99.9 million, net of issuance costs. Additionally, on September 21, 2022, we partially settled the forward sale agreement by physically delivering 1,618,932 shares of common stock in exchange for cash proceeds of approximately $80.0 million, net of issuance costs. The proceeds were used to pay down borrowings under our revolving credit facility and for other general corporate purposes.

At September 30, 2022, the remaining obligation under the forward agreements could have been settled with physical delivery of 1,960,698 common shares to the banking counterparty in exchange for cash of $96.9 million. The forward agreements could have also been settled at September 30, 2022, with delivery of $10.3 million of cash or 186,254 shares of common stock to the counterparty, if we elected net cash or net share settlement, respectively.

On May 18, 2022, we entered into an amendment and restatement of our existing $425.0 million revolving credit facility to, among other things, change the Eurodollar rate to the secured overnight financing rate as administered by the Federal Reserve Bank of New York (SOFR) and extend the maturity date of the facility from September 2, 2023 to May 18, 2027. The amended and restated credit facility (the Credit Facility) maintains the same capacity at $425.0 million and uncommitted features that allow us to request up to two one-year extensions to the maturity date and increase the size of the facility by up to an additional $75.0 million. The Credit Facility does not amortize and is unsecured. Borrowings may be made at interest rates equal to (a) SOFR, plus a credit spread adjustment of 10.0 basis points and plus a margin of 100.0 to 175.0 basis points, or (b) a base rate, plus a margin of 0.0 to 75.0 basis points.

(6) Segment Information

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

We evaluate the performance of these segments based on utility 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 us for internal reporting purposes and involves estimates and assumptions.

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

Three Months Ended September 30, 2022	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 292,270	$ 42,798	$ —	$ —	$ 335,068
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	95,553	13,367	—	—	108,920
Utility margin	196,717	29,431	—	—	226,148
Operating and maintenance	40,914	13,740	—	—	54,654
Administrative and general	20,739	7,934	(527)	—	28,146
Property and other taxes	36,353	10,110	3	—	46,466
Depreciation and depletion	40,647	7,941	—	—	48,588
Operating income (loss)	58,064	(10,294)	524	—	48,294
Interest expense, net	(18,225)	(3,238)	(3,869)	—	(25,332)
Other income (expense), net	2,944	1,727	(514)	—	4,157
Income tax (expense) benefit	(1,006)	1,119	136	—	249
Net income (loss)	$ 41,777	$ (10,686)	$ (3,723)	$ —	$ 27,368
Total assets	$ 5,741,879	$ 1,365,896	$ 6,438	$ —	$ 7,114,213
Capital expenditures	$ 122,522	$ 29,379	$ —	$ —	$ 151,901

Three Months Ended September 30, 2021	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 287,473	$ 38,482	$ —	$ —	$ 325,955
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	89,375	9,284	—	—	98,659
Utility margin	198,098	29,198	—	—	227,296
Operating and maintenance	44,319	11,683	—	—	56,002
Administrative and general	16,302	8,746	(102)	—	24,946
Property and other taxes	34,066	9,504	2	—	43,572
Depreciation and depletion	38,634	8,478	—	—	47,112
Operating income (loss)	64,777	(9,213)	100	—	55,664
Interest expense, net	(20,429)	(1,640)	(1,214)	—	(23,283)
Other income (expense), net	3,348	2,016	(38)	—	5,326
Income tax (expense) benefit	(1,680)	725	(1,556)	—	(2,511)
Net income (loss)	$ 46,016	$ (8,112)	$ (2,708)	$ —	$ 35,196
Total assets	$ 5,370,432	$ 1,291,144	$ 5,054	$ —	$ 6,666,630
Capital expenditures	$ 102,188	$ 26,778	$ —	$ —	$ 128,966

Nine Months Ended September 30, 2022	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 807,415	$ 245,139	$ —	$ —	$ 1,052,554
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	230,872	108,122	—	—	338,994
Utility margin	576,543	137,017	—	—	713,560
Operating and maintenance	121,237	39,548	—	—	160,785
Administrative and general	63,591	23,757	(338)	—	87,010
Property and other taxes	109,204	30,998	7	—	140,209
Depreciation and depletion	121,256	24,449	—	—	145,705
Operating income	161,255	18,265	331	—	179,851
Interest expense, net	(56,031)	(9,951)	(7,099)	—	(73,081)
Other income (expense)	7,245	4,669	(123)	—	11,791
Income tax (expense) benefit	(2,790)	(1,263)	1,756	—	(2,297)
Net income (loss)	$ 109,679	$ 11,720	$ (5,135)	$ —	$ 116,264
Total assets	$ 5,741,879	$ 1,365,896	$ 6,438	$ —	$ 7,114,213
Capital expenditures	$ 312,804	$ 73,535	$ —	$ —	$ 386,339

Nine Months Ended September 30, 2021	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 798,984	$ 225,991	$ —	$ —	$ 1,024,975
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	218,802	92,335	—	—	311,137
Utility margin	580,182	133,656	—	—	713,838
Operating and maintenance	122,013	37,304	—	—	159,317
Administrative and general	54,398	23,569	1,629	—	79,596
Property and other taxes	108,050	30,281	6	—	138,337
Depreciation and depletion	115,858	25,038	—	—	140,896
Operating income (loss)	179,863	17,464	(1,635)	—	195,692
Interest expense, net	(62,007)	(4,550)	(3,709)	—	(70,266)
Other income	8,392	4,035	1,505	—	13,932
Income tax (expense) benefit	(2,369)	(1,505)	20	—	(3,854)
Net income (loss)	$ 123,879	$ 15,444	$ (3,819)	$ —	$ 135,504
Total assets	$ 5,370,432	$ 1,291,144	$ 5,054	$ —	$ 6,666,630
Capital expenditures	$ 253,588	$ 57,572	$ —	$ —	$ 311,160

(7) Revenue from Contracts with Customers

Nature of Goods and Services

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

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

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

Disaggregation of Revenue

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

	Three Months Ended					
	September 30, 2022			September 30, 2021		
	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Montana	$ 85.2	$ 10.8	$ 96.0	$ 85.5	$ 9.9	$ 95.4
South Dakota	19.0	2.4	21.4	18.8	2.2	21.0
Nebraska	—	3.2	3.2	—	2.5	2.5
Residential	**104.2**	**16.4**	**120.6**	**104.3**	**14.6**	**118.9**
Montana	92.6	7.1	99.7	95.2	6.1	101.3
South Dakota	29.1	2.1	31.2	28.8	1.8	30.6
Nebraska	—	2.3	2.3	—	1.5	1.5
Commercial	**121.7**	**11.5**	**133.2**	**124.0**	**9.4**	**133.4**
Industrial	9.7	0.1	9.8	9.2	—	9.2
Lighting, governmental, irrigation, and interdepartmental	12.6	0.2	12.8	13.1	0.1	13.2
Total Customer Revenues	**248.2**	**28.2**	**276.4**	**250.6**	**24.1**	**274.7**
Other tariff and contract based revenues	22.3	8.6	30.9	26.9	8.7	35.6
Total Revenue from Contracts with Customers	**270.5**	**36.8**	**307.3**	**277.5**	**32.8**	**310.3**
Regulatory amortization and other	21.8	6.0	27.8	10.0	5.7	15.7
Total Revenues	**$ 292.3**	**$ 42.8**	**$ 335.1**	**$ 287.5**	**$ 38.5**	**$ 326.0**

	Nine Months Ended					
	September 30, 2022			September 30, 2021		
	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Montana	$ 252.9	$ 91.7	$ 344.6	$ 251.4	$ 82.4	$ 333.8
South Dakota	55.0	31.7	86.7	51.0	18.7	69.7
Nebraska	—	26.0	26.0	—	14.6	14.6
Residential	**307.9**	**149.4**	**457.3**	**302.4**	**115.7**	**418.1**
Montana	263.4	48.9	312.3	266.6	42.9	309.5
South Dakota	83.2	23.0	106.2	77.0	12.6	89.6
Nebraska	—	16.0	16.0	—	7.7	7.7
Commercial	**346.6**	**87.9**	**434.5**	**343.6**	**63.2**	**406.8**
Industrial	28.4	0.9	29.3	28.1	0.7	28.8
Lighting, governmental, irrigation, and interdepartmental	25.4	1.4	26.8	26.8	1.0	27.8
Total Customer Revenues	**708.3**	**239.6**	**947.9**	**700.9**	**180.6**	**881.5**
Other tariff and contract based revenues	64.0	27.8	91.8	69.2	27.5	96.7
Total Revenue from Contracts with Customers	**772.3**	**267.4**	**1,039.7**	**770.1**	**208.1**	**978.2**
Regulatory amortization and other	35.1	(22.2)	12.9	28.9	17.9	46.8
Total Revenues	**$ 807.4**	**$ 245.2**	**$ 1,052.6**	**$ 799.0**	**$ 226.0**	**$ 1,025.0**

(8) Earnings Per Share

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

	Three Months Ended	
	September 30, 2022	September 30, 2021
Basic computation	56,310,526	51,891,557
Dilutive effect of:		
Performance share awards[1]	14,306	136,865
Forward equity sale[2]	312,572	—
Diluted computation	56,637,404	52,028,422

	Nine Months Ended	
	September 30, 2022	September 30, 2021
Basic computation	54,901,161	51,175,345
Dilutive effect of:		
Performance share awards[1]	20,150	136,995
Forward equity sale[2]	619,361	—
Diluted computation	55,540,672	51,312,340

(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.

(2) Forward equity shares 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 forward sale agreement.

As of September 30, 2022, there were 51,829 shares from performance and restricted share awards which were antidilutive and excluded from the earnings per share calculations, compared to 23,722 shares as of September 30, 2021.

(9) Employee Benefit Plans

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

	Pension Benefits		Other Postretirement Benefits	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2022	2021	2022	2021
Components of Net Periodic Benefit Cost (Credit)				
Service cost	$ 2,555	$ 3,275	$ 88	$ 103
Interest cost	4,697	4,704	90	79
Expected return on plan assets	(6,043)	(6,841)	(262)	(230)
Amortization of prior service credit	—	—	(472)	(459)
Recognized actuarial loss (gain)	96	1,744	(13)	(8)
Net periodic benefit cost (credit)	$ 1,305	$ 2,882	$ (569)	$ (515)

	Pension Benefits		Other Postretirement Benefits	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
Components of Net Periodic Benefit Cost (Credit)				
Service cost	$ 7,667	$ 9,824	$ 263	$ 306
Interest cost	14,090	14,114	269	238
Expected return on plan assets	(18,129)	(20,525)	(785)	(689)
Amortization of prior service credit	—	—	(1,418)	(1,377)
Recognized actuarial loss (gain)	287	5,233	(37)	(23)
Net periodic benefit cost (credit)	$ 3,915	$ 8,646	$ (1,708)	$ (1,545)

We have contributed $8.2 million to our pension plans during the nine months ended September 30, 2022. We expect to contribute $3.0 million to our pension plans during the remainder of 2022.

(10) Commitments and Contingencies

Except as set forth below and in Note 2 - Regulatory Matters above, the circumstances set forth in Note 18 - Commitments and Contingencies to the financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2021 appropriately represent, in all material respects, the current status of our material commitments and contingent liabilities.

ENVIRONMENTAL LIABILITIES AND REGULATION

Environmental Matters

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

Our environmental exposure includes a number of components, including remediation expenses related to the cleanup of current or former properties, and costs to comply with changing environmental regulations related to our operations. At present, our environmental reserve, which relates primarily to the remediation of former manufactured gas plant sites owned by us or for which we are responsible, is estimated to range between $23.4 million to $30.0 million. As of September 30, 2022, we had a reserve of approximately $25.4 million, which has not been discounted. Environmental costs are recorded when it is probable we are liable for the remediation and we can reasonably estimate the liability. We use a combination of site investigations and monitoring to formulate an estimate of environmental remediation costs for specific sites. Our monitoring procedures and development of actual remediation plans depend not only on site specific information but also on coordination with the different environmental regulatory agencies in our respective jurisdictions; therefore, while remediation exposure exists, it may be many years before costs are incurred.

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

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) and methane emissions from natural gas. These actions include legislative proposals, Executive, Congressional and Environmental Protection Agency (EPA) actions at the federal level, state level activity, investor activism and private party litigation relating to GHG emissions. Coal-fired plants have come under particular scrutiny due to their level of GHG emissions. We have joint ownership interests in four coal-fired electric generating plants, all of which are operated by other companies. We are responsible for our proportionate share of the capital and operating costs while being entitled to our proportionate share of the power generated.

While numerous bills have been introduced that address climate change from different perspectives, Congress has not passed any federal climate change legislation regarding GHG emissions from coal fired plants, and we cannot predict the timing or form of any potential legislation. However, Section 111(d) of the Clean Air Act (CAA) confers authority on EPA and the states to regulate emissions, including GHGs, from existing stationary sources. EPA has acted on this authority, including in 2015 when it sought to implement the Clean Power Plan that would establish rules to control GHG emissions from existing power plants. However, neither the Clean Power Plan nor any other subsequent attempts by the EPA to regulate emissions from coal-fired plants has become effective due to litigation by various states and stakeholders. One of the key issues in the litigation revolves around whether EPA can use its CAA authority to compel fossil fuel sources to curtail operations and invest in renewable and other low carbon energy sources, in other words, establish a carbon emission cap based on a power generation source shift. The litigation culminated in the United States Supreme Court's June 30, 2022 ruling in *West Virginia, et al., v. Environmental Protection Agency, et al*, in which the Court held that the EPA does not have the authority to force major changes in the U.S. electric generation mix, as that would expand EPA's regulatory authority. In addition, the U.S. Supreme Court concluded that EPA could not meet its burden under the "major questions doctrine" to point to clear congressional authorization for this authority. The U.S. Supreme Court's ruling, however, declined to decide whether the Section 111(d) phrase "system of emissions reduction" refers exclusively to individual source control at coal-fired plants or broader energy-generating industry-wide approaches.

As expected, subsequent to that ruling, EPA opened a docket to collect public input to guide the EPA’s next effort to reduce GHG emissions from new and existing coal fired plants and natural gas operations. EPA indicated that it intends to use this non-rulemaking docket to gather perspectives from a broad group of stakeholders in advance of an expected proposed rulemaking.

Therefore, we cannot predict whether or how future GHG emission regulations or litigation will impact our plants, including any actions taken by federal or state authorities, or courts. As GHG regulations are implemented, it could result in additional compliance costs impacting our future results of operations and financial position if such costs are not recovered through regulated rates. We will continue working with federal and state regulatory authorities, other utilities, and stakeholders to seek relief from any GHG regulations that, in our view, disproportionately impact customers in our region.

Future additional environmental requirements - federal or state - 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, wind, 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.

LEGAL PROCEEDINGS

Pacific Northwest Solar Litigation

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

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

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

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

In August 2017, we entered into a non-monetary, partial settlement with PNWS in which PNWS amended its original complaint to limit its claims for enforcement and/or damages to only four of the 21 power purchase agreements. As a result, the damages sought by the plaintiff were reduced to approximately $8.0 million for the alleged breach of the four power purchase agreements. We participated in an unsuccessful mediation on January 24, 2019 and subsequent settlement efforts also have been unsuccessful.

On August 31, 2021, the District Court ruled that the four agreements were valid and enforceable contracts and that we breached the agreements on June 16, 2016 by refusing to go forward with the projects in spite of the MPSC's Orders. On December 15, 2021, after a three-day trial, the jury determined that PNWS had sustained $0.5 million in damages and the judge subsequently entered judgment against us in that amount.

We filed a post-trial motion on January 13, 2022 seeking to have the judgment set aside. On February 9, 2022, the judge denied our post-trial motion. We filed our Notice of Appeal to the Ninth Circuit Court of Appeals on March 1, 2022, and PNWS filed its Cross-Notice of Appeal on March 9, 2022. Briefing has concluded, and we expect that the Ninth Circuit will hear oral arguments before rendering a decision.

While the Ninth Circuit had encouraged the parties to engage in a voluntary court-supervised mediation, the Court has subsequently determined that further discussions would be unproductive and released both parties from the mediation process.

Talen Montana Bankruptcy

On May 9, 2022 Talen Energy Supply, LLC (Talen Energy) along with 71 affiliated entities, filed bankruptcy in Houston, Texas, seeking reorganization under Chapter 11 (the Talen Bankruptcy). Talen Montana, LLC (Talen) was one of the affiliated entities that filed bankruptcy and is included as a part of the Talen Bankruptcy. Talen is one of the co-owners of Colstrip Units 1, 2 and 3, and the operator of Units 3 and 4. The Talen Bankruptcy filing, along with the automatic stay under §362 of the Bankruptcy Code, affects pending legal proceedings in which both NorthWestern and Talen are involved, including the State of Montana-Riverbed Rents Litigation, the Colstrip Arbitration and Litigation, and the Colstrip Coal Dust Litigation, as described in the individual matters below. As the Talen Bankruptcy is in its early stages, we are unable to predict the ultimate effect, if any, on Colstrip Units 3 and 4, or other matters in which both NorthWestern and Talen are presently engaged.

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 as defendants. The State claimed it owns the riverbeds underlying 10 of our, and formerly Talen's, hydroelectric facilities (dams, along with reservoirs and tailraces) on the Missouri, Madison and Clark Fork Rivers, and seeks rents for Talen's and our use and occupancy of such lands. The facilities at issue include the Hebgen, Madison, Hauser, Holter, Black Eagle, Rainbow, Cochrane, Ryan, and Morony facilities on the Missouri and Madison Rivers and the Thompson Falls facility on the Clark Fork River. We acquired these facilities from Talen in November 2014.

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

Because the State's Complaint included a claim that the State owned the riverbeds in the Great Falls Reach, on October 16, 2017, we and Talen renewed our earlier-filed motions seeking to dismiss the portion of the State's Complaint concerning the Great Falls Reach in light of the United States Supreme Court's decision. On August 1, 2018, the Federal District Court granted the motions to dismiss the State's Complaint as it pertains to approximately 8.2 miles of riverbed from "the head of the Black Eagle Falls to the foot of the Great Falls." In particular, the dismissal pertained to the Black Eagle Dam, Rainbow Dam and reservoir, Cochrane Dam and reservoir, and Ryan Dam and reservoir. While the dismissal of these four facilities may be subject to appeal, that appeal would not likely occur until after judgment in the case. On February 12, 2019, the Federal District Court granted our motion to join the United States as a defendant to the litigation. As a result, on October 31, 2019, the State filed and served an Amended Complaint including the United States as a defendant and removing claims of ownership for the hydroelectric facilities on the Great Falls Reach, except for the Morony and the Black Eagle Developments. We and Talen filed answers to the Amended Complaint on December 13, 2019, and the United States answered on February 5, 2020. A bench trial before the Federal District Court commenced January 4, 2022 and concluded on January 18, 2022. This bench trial addressed the issue of navigability of the segments at issue. Damages were bifurcated by agreement and will be tried separately, should the Federal District Court find any segments navigable.

On April 29, 2022, the parties submitted amended findings of fact and conclusions of law, along with post-trial briefing. The parties, other than Talen, filed responses on May 13, 2022. Talen did not file a response, as it had filed bankruptcy on May 9, 2022. In its response, the State sought to sever Talen and proceed solely against NorthWestern and the United States. A decision on navigability was expected following these submissions. However, the Talen Bankruptcy and resulting automatic stay, resulted in a hold on this case, including a hold on any decision regarding navigability and the State's severance request. The Federal District Court, by order issued June 23, 2022, confirmed it will not rule on the severance until the bankruptcy stay is lifted or ends. On July 16, 2022, Talen filed an adversary complaint in Talen's Bankruptcy, asking the Bankruptcy Court to extend the stay to NorthWestern. Before resolution of the adversary complaint, the parties stipulated and the Bankruptcy Court issued its Order modifying the stay to permit Talen to file its response to the State's amended proposed findings and conclusions and allow the Federal District Court to issue its decision on the navigability phase of the case. The Federal District Court is free to issue its decision on navigability. The damages phase of the case remains stayed.

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

Colstrip Arbitration and Litigation

As part of the settlement of litigation brought by the Sierra Club and the MEIC against the owners and operator of Colstrip, the owners of Units 1 and 2 agreed to shut down those units no later than July 2022. In January 2020, the owners of Units 1 and 2 closed those two units. We do not have ownership in Units 1 and 2, and decisions regarding those units, including their shut down, were made by their respective owners. The six owners of Units 3 and 4 currently share the operating costs pursuant to the terms of an operating agreement among them, the Ownership and Operation Agreement (O&O Agreement). Costs of common facilities were historically shared among the owners of all four units. With the closure of Units 1 and 2, we have incurred additional operating costs with respect to our interest in Unit 4 and may experience a negative impact on our transmission revenue due to reduced amounts of energy transmitted across our transmission lines.

The remaining depreciable life of our investment in Colstrip Unit 4 is through 2042. Recovery of costs associated with the closure of the facility is subject to MPSC approval. Three of the joint owners of Units 3 and 4 are subject to regulation in Washington and in May 2019, the Washington state legislature enacted a statute mandating Washington electric utilities to "eliminate coal-fired resources from [their] allocation of electricity" on or before December 31, 2025, after which date they may no longer include their share of coal-fired resources in their regulated electric supply portfolio.

While we believe closure requires each owner's consent, there are differences among the owners as to this issue under the O&O Agreement. On March 12, 2021, we initiated an arbitration under the O&O Agreement (the "Arbitration"), which seeks to resolve the primary issue of whether closure of Units 3 and 4 can be accomplished without each joint owner's consent and to clarify the obligations of the joint owners to continue to fund operations until all joint owners agree on closure.

The threat of early closure led the Montana Legislature to enact, and the Montana Governor to sign into law, Senate Bill 265 (SB 265) and Senate Bill 266 (SB 266). SB 265 requires arbitrations involving a Montana electric utility to be heard in Montana before a panel of three arbitrators, which, if enforced, would alter the O&O Agreement's arbitration provision. SB 266 allows the Montana Attorney General (Montana AG) to bring legal action against an owner of a jointly-owned facility who fails or refuses to fund its share of operating costs or who acts to bring about permanent closure of a generating unit of a facility without seeking and obtaining the consent of all co-owners. If an owner is found to have acted willfully in so acting, the Montana AG may seek a daily fine of $100,000 for each violation.

The Arbitration has given rise to three lawsuits challenging the constitutionality of SB 265 and SB 266. Four of the six joint owners of Units 3 and 4 (The Pacific Northwest Owners) have asserted that the Arbitration must be conducted under the O&O Agreement, with one arbitrator, in Spokane County, Washington, and pursuant to the Washington Arbitration Act. The fifth joint owner asserts the Arbitration must be conducted per the terms of SB 265, which requires the Arbitration be conducted, with three arbitrators, in Montana and pursuant to the Montana Uniform Arbitration Act. The Pacific Northwest Owners have added the Montana AG as a defendant and claim SB 266 is unenforceable as contrary to the U.S. and Montana constitutions. On October 13, 2021 (as clarified on December 17, 2021), the United States District Court for the District of Montana granted a preliminary injunction enjoining the Montana AG from enforcing SB 266. The Pacific Northwest Owners have moved for summary judgment on their claims SB 265 and SB 266 are unconstitutional. We have also moved the court to compel the parties to arbitration. Those motions along with a request by the Montana AG to stay the judicial proceedings were heard by the Magistrate Judge on April 26, 2022. However, the Talen Bankruptcy and automatic stay resulted in a hold on this case, including a hold on any decision regarding NorthWestern's motion to compel arbitration. On August 25, 2022, the Bankruptcy Court approved a stipulation entered into by Talen, the Pacific Northwest Owners and NorthWestern to modify the automatic stay, to allow the Magistrate Judge to issue her ruling regarding SB 265, SB 266 and to permit the parties to proceed to arbitration.

On September 28, 2022, the Magistrate Judge recommended that SB 265 be found pre-empted by the Federal Arbitration Act and in violation of the contracts clauses of both the United States' and Montana Constitutions. She also recommended that SB 266 be found to violate the contracts clauses of the United States and Montana Constitutions and the commerce clause of the United States Constitution. All parties had until October 12, 2022, to object to the Magistrate Judge's recommendations. No objections were made. On October 18, 2022, the Federal District Court Judge adopted the Magistrate Judge's recommendations, in full, and entered a final order granting summary judgment as recommended.

The three initiated lawsuits do not make direct financial demands, and instead, address issues related to the process for the Arbitration and for closure of the facility. The pendency of the lawsuits and Talen's Bankruptcy have delayed commencement of the Arbitration proceedings and thus delayed resolution of the issues we raised when we commenced arbitration. Since the Arbitration was initiated, and despite the litigation, we have worked and continue to work with the other joint owners to arrive at an agreed upon process for the Arbitration.

Colstrip Coal Dust Litigation

On December 14, 2020, a claim was filed against Talen, the operator of the Colstrip Units 1, 2, 3 and 4 (Colstrip), in the Montana Sixteenth Judicial District Court, Rosebud County, Cause No. CV-20-58. The plaintiffs allege they have suffered adverse effects from coal dust generated during operations associated with Colstrip. On August 26, 2021, the claim was amended to add in excess of 100 plaintiffs. It also added NorthWestern, as well as the other owners of Colstrip, and Westmoreland Rosebud Mining LLC, as defendants. Plaintiffs are seeking economic damages, costs and disbursements, punitive damages, attorneys' fees, and an injunction prohibiting defendants from allowing coal dust to blow onto plaintiffs' properties. Talen's bankruptcy and resulting automatic stay prevents the plaintiffs from pursuing their claims against Talen, but does not automatically prevent the plaintiffs from pursuing their claims against the other defendants. On September 26, 2022 the Bankruptcy Court extended the stay as to Talen and the other defendants until 60 days after the date Talen's plan of reorganization is confirmed by the Bankruptcy Court.

Since this lawsuit is in its early stages, we are unable to predict outcomes or estimate a range of reasonably possible losses.

BNSF Demands for Indemnity and Remediation Costs

NorthWestern has received a demand for indemnity from BNSF Railway Company (BNSF) for past and future environmental investigation and remediation costs incurred by BNSF at one of the three operable units at the Anaconda Copper Mining (ACM) Smelter and Refinery Superfund Site, located near Great Falls, Montana. Smelter and refining operations at the site commenced in 1893 and continued until 1980.

According to U.S. EPA, the smelter and refining operations have contaminated soil, groundwater and surface water resources around the site with lead, arsenic and other metal wastes. ARCO (Atlantic Richfield Company) initiated reclamation and maintenance activities in the 1980s and 1990s. Between 2002 and 2008, the EPA conducted several site investigations. In March 2011, the EPA placed the ACM Smelter and Refinery Site on the Superfund program's National Priority List. The Superfund Site is 427 acres and contains three operable units: Operable Unit 1 (consisting of five subsections including the Railroad Corridor and four other "areas of interest"), Operable Unit 2 (the former smelter and refinery site), and Operable Unit 3 (the Missouri River that flows along the south sides of Operable Units 1 and 2).

NorthWestern owns property in the Railroad Corridor sub-section of Operable Unit 1. BNSF claims it is entitled to indemnity and contribution from NorthWestern for the costs it has and will incur to investigate and remediate contamination in Operable Unit 1. BNSF reports it has incurred in excess of $4.4 million, pending final resolution of response and oversight costs incurred by government agencies (EPA and Montana DEQ), in investigative and other response costs associated with Operable Unit 1, and that in the future it will incur additional costs to implement the final remedy for Operable Unit 1. In the Record of Decision (ROD) for Operable Unit 1 issued on August 21, 2021, the EPA estimated the costs to implement the selected remedies for the Railroad Corridor will be approximately $4.1 million. In the ROD, the EPA also estimated the costs to implement the selected remedy (including institutional controls) for the four "areas of interest" in Operable Unit 1 would be approximately $1.8 million, with annual operating costs of ten thousand dollars. We are evaluating BNSF's claim and are unable at this time to predict outcomes or estimate a range of reasonably possible losses.

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 our opinion, 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

Non-GAAP Financial Measure

The following discussion includes financial information prepared in accordance with GAAP, as well as another financial measure, Utility Margin, that is considered a "non-GAAP financial measure." Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. We define Utility Margin as Operating Revenues less fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion) as presented in our Condensed Consolidated Statements of Income. This measure differs from the GAAP definition of Gross Margin due to the exclusion of Operating and maintenance, Property and other taxes, and Depreciation and depletion expenses, which are presented separately in our Condensed Consolidated Statements of Income. The following discussion includes a reconciliation of Utility Margin to Gross Margin, the most directly comparable GAAP measure.

We believe that Utility Margin provides a useful measure for investors and other financial statement users to analyze our financial performance in that it excludes the effect on total revenues caused by volatility in energy costs and associated regulatory mechanisms. This information is intended to enhance an investor's overall understanding of results. Under our various state regulatory mechanisms, as detailed below, our supply costs are generally collected from customers. In addition, Utility 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 Utility Margin measure may not be comparable to that of other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

OVERVIEW

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and/or natural gas to approximately 753,600 customers in Montana, South Dakota, Nebraska and Yellowstone National Park. 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, 2021.

We are working to deliver safe, reliable and innovative energy solutions that create value for customers, communities, employees and investors. This includes bridging our history as a regulated utility safely providing low-cost and reliable service with our future as a globally-aware company offering a broader array of services performed by highly-adaptable and skilled employees. We seek to deliver value to our customers by providing high reliability and customer service, and an environmentally sustainable generation mix at an affordable price. The energy landscape is changing and we are committed to meeting the changing demands of our customers through continued investment to enhance reliability, security and safety, grid modernization, and integration of even more renewables and energy storage, while meeting our growing demand for capacity. We are focused on delivering long-term shareholder value through:

- Infrastructure investment focused on a stronger and smarter grid to improve the customer experience, while enhancing grid reliability and safety. This includes automation in customer meters, distribution and substations that enables the use of proven new technologies.

- Investing in and integrating supply resources that balance reliability, cost, capacity, and sustainability considerations with more predictable long-term commodity prices.

- Continually improving our operating efficiency. Financial discipline is essential to earning our authorized return on invested capital and maintaining a strong balance sheet, stable cash flows, and quality credit ratings to continue to attract cost-effective capital for future investment.

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

We are committed to providing customers with reliable and affordable electric and natural gas service while also being good stewards of the environment. Towards this end, we recently expanded and outlined our efforts towards a carbon-free future through our goal to achieve net zero carbon emissions by 2050.

As you read this discussion and analysis, refer to our Condensed Consolidated Statements of Income, which present the results of our operations for the three and nine months ended September 30, 2022 and 2021.

HOW WE PERFORMED AGAINST OUR THIRD QUARTER 2021 RESULTS

	Three Months Ended September 30, 2022 vs. 2021		
	Income Before Income Taxes	Income Tax (Expense) Benefit	Net Income
	(in millions)		
Third Quarter 2021	**$ 37.7**	**$ (2.5)**	**$ 35.2**
Variance in revenue and fuel, purchased supply, and direct transmission expense[1] items impacting net income:			
Lower transmission revenue due to lower transmission demand due to market conditions and lower pricing	(4.7)	1.2	(3.5)
Higher non-recoverable Montana electric supply costs	(1.3)	0.3	(1.0)
Lower natural gas retail volumes	(0.6)	0.2	(0.4)
Higher electric retail volumes	2.1	(0.5)	1.6
Prior year unfavorable electric QF liability adjustment	1.3	(0.3)	1.0
Variance in expense items[2] impacting net income:			
Higher interest expense	(2.0)	0.5	(1.5)
Higher operating, maintenance, and administrative expenses	(1.9)	0.5	(1.4)
Higher depreciation expense due to plant additions	(1.5)	0.4	(1.1)
Higher property tax expenses due to an increase in estimated state and local taxes	(0.7)	0.2	(0.5)
Other	(1.3)	0.3	(1.0)
Third Quarter 2022	**$ 27.1**	**$ 0.3**	**$ 27.4**
Change in Net Income			**$ (7.8)**

(1) Exclusive of depreciation and depletion shown separately below
(2) Excluding fuel, purchased supply, and direct transmission expense

Consolidated net income for the three months ended September 30, 2022 was $27.4 million as compared with $35.2 million for the same period in 2021. This decrease was primarily due to lower transmission revenues, higher interest expense, higher operating costs, higher depreciation and depletion, higher non-recoverable Montana electric supply costs and lower natural gas retail volumes due to unfavorable weather, partly offset by higher electric retail volumes due to favorable weather and customer growth and a prior year unfavorable electric QF liability adjustment.

SIGNIFICANT TRENDS AND REGULATION

Regulatory Update

Rate Review Filings – Rate reviews are necessary to recover the cost of providing safe, reliable service, while contributing to earnings growth and achieving our financial objectives. We regularly review the need for electric and natural gas rate relief in each state in which we provide service. On August 8, 2022, we filed a Montana electric and natural gas rate review filing (2021 test year) under Docket 2022.07.78. A summary of our requests within this rate review is below:

Montana Rate Review ($ in millions)

	Electric	Natural Gas
Current ROE	9.65%	9.55%
Current Equity Ratio	49.38%	46.79%
Proposed ROE	10.60%	10.60%
Proposed Equity Ratio	48.02%	48.02%
Forecasted 2022 Rate Base	$2,790	$575
Net Rate Base Increase	$453	$143

Requested Revenue Increase (in millions)

	Electric	Natural Gas
Base Rates	$91.8	$20.2
Power Cost & Credit Mechanism (PCCAM)(1)	$68.1	n/a
Property Tax (tracker true-up)(1)	$11.1	$2.8
Total	$171.0	$23.0

(1) These items are flow-through costs, which represent approximately 42% of the requested electric and natural gas revenue increase.

Within this rate review filing we requested an increase to the PCCAM base rate (PCCAM Base) of $68.1 million as well as structural revisions to the PCCAM mechanism to provide customers with prices that better reflect the cost of services received. We also proposed to implement a revised electric only pilot for the Fixed Cost Recovery Mechanism (FCRM) beginning July 1, 2023, or alternatively to terminate the FCRM. Our rate review filing also includes proposals for more timely cost recovery beyond the test period, including critical reliability resources, such as the Yellowstone Generating Station, our Enhanced Wildfire Mitigation plan, and business technology maintenance costs.

Interim Rates - On September 28, 2022, the MPSC approved the recommendations of the MPSC Staff for interim rates, subject to refund, which increased base electric rates $29.4 million, PCCAM Base rates $61.1 million, and base natural gas rates $1.7 million, effective October 1, 2022.

Key dates in the procedural schedule are expected to be as follows:

- Intervenor testimony - December 19, 2022
- NorthWestern rebuttal testimony and cross-intervenor testimony - March 6, 2023
- Hearing commences - April 10, 2023

Montana Power Costs and Credits Adjustment Mechanism (PCCAM) - The current Montana PCCAM Base of $138.7 million, approved in 2019, no longer reflects an accurate current forecast of our normal fuel and power costs. As of September 30, 2022, we have under-collected our total Montana electric supply costs for the current July 2022 through June 2023 PCCAM year by approximately $28.6 million. Under-collections are not reflected in customer bills and are not recovered until the subsequent power cost adjustment year, adversely affecting our cash flows and liquidity. The MPSC's September 28, 2022 decision approving interim rates in our rate review included an increase to the PCCAM Base of $61.1 million, on an interim basis, effective October 1, 2022.

Under the PCCAM, under and over-collection of non-qualifying facility related net costs are allocated 90% to Montana customers and 10% to shareholders. For the three and nine months ended September 30, 2022, we deferred $35.4 million and $50.0 million of costs, respectively, to be collected from customers (90% of the costs above base) and recorded a reduction in pre-tax earnings of $3.9 million and $5.6 million, respectively (10% of the variance). For the three and nine months ended September 30, 2021, we deferred $25.4 million and $37.6 million, respectively, of costs for future collection from customers and recorded a reduction in pre-tax earnings of $2.8 million and $4.2 million, respectively.

Holding Company Filings - On June 1, 2022, we filed a legal corporate restructuring application (Restructuring Plan) with the state commissions in Montana, South Dakota and Nebraska and the FERC. Currently, our utility businesses are held in the same legal entity. Under the proposed Restructuring Plan, we would legally separate our Montana public utility business from our South Dakota and Nebraska public utility business and establish a holding company to hold the ownership interests of all of the subsidiaries. The purpose of the reorganization is to integrate our organizational structure to be more transparent and in line with the public utility industry.

The Restructuring Plan does not propose and we do not expect any procedural or substantive change in how the state public utility commissions regulate those services. Implementation of the Restructuring Plan is subject to receipt of all regulatory approvals. On July 26, 2022, the Nebraska Public Service Commission approved our Restructuring Plan application. On August

3, 2022, the South Dakota Public Utilities Commission approved the application. We expect FERC to release a decision during the fourth quarter of 2022. The MPSC is expected to hold a hearing on our Restructuring Plan on January 11, 2023.

Electric Resource Planning - Montana

Yellowstone County 175 MW plant - Construction at the site began in April 2022 with a current schedule that is expected to allow the plant to serve our Montana customers during 2024 with total construction costs of approximately $275.0 million ($98.1 million incurred through September 30, 2022).

On October 21, 2021, the MEIC and the Sierra Club filed a lawsuit in Montana State Court, against the Montana Department of Environmental Quality (MDEQ) and us, alleging that the environmental analysis conducted prior to issuance of the Yellowstone County project's air quality permit was inadequate. The Montana District Court judge held oral argument on June 20, 2022. We expect a decision during the fourth quarter of 2022. This lawsuit, as well as additional legal challenges related to the Yellowstone County plant, could delay the project timing.

Beartooth Battery 50 MW project - On December 21, 2021, we filed an application with the MPSC for preapproval of the Beartooth Battery agreement as a new capacity resource. This agreement is contingent upon MPSC approval of our application. As discussed below under Risk Factors, the Montana District Court ruled that the Montana preapproval statute (that serves as the basis for our Beartooth Battery agreement application) is unconstitutional. On October 18, 2022, the MPSC dismissed our application because the statute upon which the application was filed was found unconstitutional.

Future Integrated Resource Planning - To comply with statutory resource planning requirements, we expect to submit an integrated resource plan to the MPSC by the end of 2022, followed by an all-source competitive solicitation request for capacity available in 2026. Due to the significant impact of our ownership in Colstrip Unit 4 to the capacity available in our portfolio, the outcome in the arbitration amongst the co-owners (See Note 10 - Commitments and Contingencies) may affect this plan.

Electric Resource Supply - South Dakota

Our new Bob Glanzer Generating Station was operational as of May 27, 2022. The 58 MW natural gas plant is located in Huron, South Dakota. Construction was completed under budget at a total cost of approximately $83.1 million.

Our electric supply resource plans for South Dakota continue to identify portfolio requirements including potential investments resulting from a completed competitive solicitation process. We filed an updated integrated resource plan on September 6, 2022, which is consistent with the prior plan laying out a retire and replace generation asset strategy. A decision whether to use a competitive solicitation process, and what type of generation technology to add, is expected to be made in 2023.

Supply Chain and Inflation Challenges

We place significant reliance on our third-party business partners to supply materials, equipment and labor necessary for us to operate our utility and reliably serve current customers and future customers. As a result of current macroeconomic conditions, both nationally and globally, we have recently experienced issues with our supply chain for materials and components used in our operations and capital project construction activities. Issues include higher prices, scarcities/shortages, longer fulfillment times for orders from our suppliers, workforce availability, and wage increases. Should these conditions continue, we could have difficulty completing the operations activities necessary to serve our customers safely and reliably, and/or achieving our capital investment program, which ultimately could result in higher customer utility rates, longer outages, and could have a material adverse impact on our business, financial condition and operations.

During the third quarter of 2021, we decided to discontinue our plans to build a 30-40 MW electric generation plant near Aberdeen, South Dakota as a result of significant increases in estimated construction cost as a result of global supply chain challenges. At this time, our forecasted 2022 capital investment remains consistent with the $582.0 million disclosed within our Annual Report on Form 10-K for the year ended December 31, 2021, as rising costs have been offset by delays in project timelines. Continued challenges with product and services availability and price inflation could cause further project delays and impact our capital investment forecasts.

Fire Mitigation

With changing weather conditions which include more significant wind events, drought conditions, and warmer air temperatures, we do not consider the fire season specific to a time of year, but rather a condition that may exist at any time of year. Each year’s weather conditions impact these situations differently: early season rains encourage plant growth which fuels fires later in the growing season, and winters with little snow leave dry plant material available for late season fires. The threat is not only in forested areas, where insect infestations and resulting tree death has been severe, but across the entire system including rural areas where grassland fires could be ignited, along with urban areas where extreme weather conditions pose a great risk to heavily populated areas.

Recognizing the risk of significant wildfires in Montana, we continue to proactively seek to mitigate wildfire risk. We have developed an Enhanced Fire Mitigation Plan addressing five key areas: situational awareness, operational practices, system preparedness, vegetation management, and public communications and outreach. This plan builds upon several key initiatives that were initiated and executed over the past decade including nearly $80 million spent on vegetation management and hazard tree removal programs and our growing annual investment to harden our transmission and distribution system infrastructure. Because of ever-increasing wildfire risk, our plan includes greater focus on situational awareness to monitor changing environmental conditions, operational practices that are more reactive to changing conditions, increased frequency of patrol and repairs, and more robust system hardening programs that target higher risk segments in our transmission and distribution systems. We included a request for expected costs associated with the mitigation plan in our 2022 Montana rate review.

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 utility margin by segment.

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.

Fuel, purchased supply and direct transmission expenses are costs directly associated with the generation and procurement of electricity and natural gas. Among the most significant of these costs are those associated with fuel, purchased power, natural gas supply, and transmission expense. These costs are generally collected in rates from customers and may fluctuate substantially with market prices and customer usage.

Operating and maintenance expenses are costs associated with the ongoing operation of our vertically-integrated utility facilities which provide electric and natural gas utility products and services to our customers. Among the most significant of these costs are those associated with direct labor and supervision, repair and maintenance expenses, and contract services. These costs are normally fairly stable across broad volume ranges and therefore do not normally increase or decrease significantly in the short term with increases or decreases in volumes.

OVERALL CONSOLIDATED RESULTS

Three Months Ended September 30, 2022 Compared with the Three Months Ended September 30, 2021

Consolidated net income for the three months ended September 30, 2022 was $27.4 million as compared with $35.2 million for the same period in 2021. This decrease was primarily due to lower transmission revenues, higher interest expense, higher administrative and general costs, higher depreciation and depletion, and lower natural gas retail volumes due to unfavorable weather, partly offset by higher electric retail volumes due to favorable weather and customer growth, and a prior year unfavorable electric QF liability adjustment.

Consolidated gross margin for the three months ended September 30, 2022 was $76.3 million as compared with $80.6 million in 2021, a decrease of $4.3 million, or 5.3 percent. This decrease was primarily due to lower transmission revenue, higher non-recoverable Montana electric supply costs, lower natural gas volumes due to unfavorable weather, and higher depreciation and depletion costs, partly offset by higher electric retail volumes due to favorable weather and customer growth and the unfavorable adjustment to our electric QF liability in the prior year.

	Electric		Natural Gas		Total	
	2022	2021	2022	2021	2022	2021
	(in millions)					
Reconciliation of gross margin to utility margin:						
Operating Revenues	$ 292.3	$ 287.5	$ 42.8	$ 38.5	$ 335.1	$ 326.0
Less: Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	95.6	89.4	13.4	9.3	109.0	98.7
Less: Operating and maintenance	40.9	44.3	13.8	11.7	54.7	56.0
Less: Property and other taxes	36.4	34.1	10.1	9.5	46.5	43.6
Less: Depreciation and depletion	40.7	38.6	7.9	8.5	48.6	47.1
Gross Margin	**78.7**	**81.1**	**(2.4)**	**(0.5)**	**76.3**	**80.6**
Operating and maintenance	40.9	44.3	13.8	11.7	54.7	56.0
Property and other taxes	36.4	34.1	10.1	9.5	46.5	43.6
Depreciation and depletion	40.7	38.6	7.9	8.5	48.6	47.1
Utility Margin(1)	**$ 196.7**	**$ 198.1**	**$ 29.4**	**$ 29.2**	**$ 226.1**	**$ 227.3**

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

	Three Months Ended September 30,			
	2022	2021	Change	% Change
	(dollars in millions)			
Utility Margin				
Electric	$ 196.7	$ 198.1	$ (1.4)	(0.7) %
Natural Gas	29.4	29.2	0.2	0.7
Total Utility Margin(1)	**$ 226.1**	**$ 227.3**	**$ (1.2)**	**(0.5)%**

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

Consolidated utility margin for the three months ended September 30, 2022 was $226.1 million as compared with $227.3 million for the same period in 2021, a decrease of $1.2 million, or 0.5 percent.

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

	Utility Margin 2022 vs. 2021
Utility Margin Items Impacting Net Income	
Lower transmission revenue due to lower transmission demand due to market conditions and lower pricing	$ (4.7)
Higher non-recoverable Montana electric supply costs	(1.3)
Lower natural gas retail volumes	(0.6)
Higher electric retail volumes	2.1
Prior year unfavorable electric QF liability adjustment	1.3
Change in Utility Margin Items Impacting Net Income	**(3.2)**
Utility Margin Items Offset Within Net Income	
Higher property taxes recovered in revenue, offset in property tax expense	2.2
Lower revenue from higher production tax credits, offset in income tax expense	(0.1)
Lower operating expenses recovered in revenue, offset in operating and maintenance expense	(0.1)
Change in Utility Margin Items Offset Within Net Income	**2.0**
Decrease in Consolidated Utility Margin[(1)]	**$ (1.2)**

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

Higher electric retail volumes were driven by warmer summer weather in Montana and customer growth, partly offset by lower Montana commercial demand. Lower natural gas volumes were driven by warmer summer weather in Montana, partly offset by customer growth.

The prior year unfavorable adjustment to our electric QF liability (unrecoverable costs associated with contracts covered by the Public Utility Regulatory Policies Act of 1978 (PURPA) as part of a 2002 stipulation with the MPSC and other parties) is associated with a one-time clarification in contract term in 2021.

	Three Months Ended September 30,			
	2022	**2021**	**Change**	**% Change**
	(dollars in millions)			
Operating Expenses (excluding fuel, purchased supply and direct transmission expense)				
Operating and maintenance	$ 54.7	$ 56.0	$ (1.3)	(2.3) %
Administrative and general	28.1	24.9	3.2	12.9
Property and other taxes	46.5	43.6	2.9	6.7
Depreciation and depletion	48.6	47.1	1.5	3.2
Total Operating Expenses (excluding fuel, purchased supply and direct transmission expense)	**$ 177.9**	**$ 171.6**	**$ 6.3**	**3.7 %**

Consolidated operating expenses, excluding fuel, purchased supply and direct transmission expense, were $177.9 million for the three months ended September 30, 2022, as compared with $171.6 million for the three months ended September 30, 2021. Primary components of the change include the following (in millions):

	Operating Expenses 2022 vs. 2021	
Operating Expenses (excluding fuel, purchased supply and direct transmission expense) Impacting Net Income		
Higher depreciation expense due to plant additions	$	1.5
Higher property tax expenses due to an increase in estimated state and local taxes		0.7
Increase in uncollectible accounts due to the prior year collection of previously written off balances		0.5
Higher line clearance expenses		0.4
Higher litigation expenses		0.4
Higher travel expenses		0.4
Prior year write-off of preliminary construction costs		(1.2)
Lower labor and benefits(1)		(0.6)
Lower technology implementation and maintenance expenses		(0.3)
Other		2.3
Change in Items Impacting Net Income		**4.1**
Operating Expenses Offset Within Net Income		
Higher property and other taxes recovered in trackers, offset in revenue		2.2
Higher pension and other postretirement benefits, offset in other income(1)		0.6
Lower non-employee directors deferred compensation recorded within administrative and general expense, offset in other income		(0.5)
Lower operating and maintenance expenses recovered in trackers, offset in revenue		(0.1)
Change in Items Offset Within Net Income		**2.2**
Increase in Operating Expenses (excluding fuel, purchased supply and direct transmission expense)	**$**	**6.3**

(1) In order to present the total change in labor and benefits, we have included the change in the non-service cost component of our pension and other postretirement benefits, which is recorded within other income on our Condensed Consolidated Statements of Income. This change is offset within this table as it does not affect our operating expenses.

We estimate property taxes throughout each year, and update those estimates based on valuation reports received from the Montana Department of Revenue. Under Montana law, we are allowed to track the increases and decreases in the actual level of state and local taxes and fees and adjust our rates to recover the increase or decrease between rate cases less the amount allocated to FERC-jurisdictional customers and net of the associated income tax benefit.

Consolidated operating income for the three months ended September 30, 2022 was $48.3 million as compared with $55.7 million in the same period of 2021. This decrease was primarily driven by lower transmission revenue, higher non-recoverable Montana electric supply costs, higher administrative and general costs, and higher depreciation and depletion, partly offset by higher electric retail volumes, a prior year unfavorable QF liability adjustment, and lower operating and maintenance expense.

Consolidated interest expense was $25.3 million for the three months ended September 30, 2022 as compared with $23.3 million for the same period of 2021. This increase was primarily due to higher interest on borrowings under our revolving credit facilities partly offset by higher capitalization of Allowance for Funds Used During Construction (AFUDC).

Consolidated other income was $4.2 million for the three months ended September 30, 2022 as compared to $5.3 million during the same period of 2021. This decrease was primarily due to a decrease in the value of deferred shares held in trust for non-employee directors deferred compensation, partly offset by a decrease in the non-service component of pension expense.

Consolidated income tax benefit was $0.2 million for the three months ended September 30, 2022 as compared to income tax expense of $2.5 million for the three months ended September 30, 2021. Our effective tax rate for the three months ended

September 30, 2022 was (0.9)% as compared with 6.6% for the same period in 2021. We expect our effective tax rate to range between 0% to 3% in 2022.

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

	Three Months Ended September 30,			
	2022		2021	
Income Before Income Taxes	$ 27.1		$ 37.7	
Income tax calculated at federal statutory rate	5.7	21.0 %	7.9	21.0 %
Permanent or flow-through adjustments:				
State income tax, net of federal provisions	0.1	0.5	0.4	1.1
Flow-through repairs deductions	(3.4)	(12.4)	(3.5)	(9.2)
Production tax credits	(1.7)	(6.2)	(1.9)	(5.0)
Income tax return to accrual adjustment	(0.9)	(3.4)	0.4	1.0
Amortization of excess deferred income tax	(0.2)	(0.9)	(0.1)	(0.3)
Share-based compensation	—	—	(0.1)	(0.2)
Plant and depreciation of flow-through items	0.3	1.0	(0.3)	(0.8)
Other, net	(0.2)	(0.5)	(0.3)	(1.0)
	(6.0)	(21.9)	(5.4)	(14.4)
Income tax (benefit) expense	$ (0.3)	(0.9)%	$ 2.5	6.6 %

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.

Nine Months Ended September 30, 2022 Compared with the Nine Months Ended September 30, 2021

Consolidated net income for the nine months ended September 30, 2022 was $116.3 million as compared with $135.5 million for the same period in 2021. This decrease was primarily due to lower transmission revenues due to the prior year recognition of deferred transmission revenue and lower prices, a less favorable electric QF liability adjustment as compared to the prior period, higher administrative and general costs, higher depreciation and depletion, and higher interest expense, partly offset by higher electric and natural gas retail volumes due to favorable weather and customer growth.

Consolidated gross margin for the nine months ended September 30, 2022 was $266.9 million as compared with $275.4 million in 2021, a decrease of $8.5 million, or 3 percent. This decrease was primarily due to lower transmission revenues due to the prior year recognition of deferred transmission revenue and lower prices, less favorable electric QF liability adjustment as compared to the prior period, higher operating and maintenance costs, and higher depreciation and depletion, partly offset by higher electric and natural gas retail volumes due to favorable weather and customer growth.

	Electric		Natural Gas		Total	
	2022	2021	2022	2021	2022	2021
	(in millions)					
Reconciliation of gross margin to utility margin:						
Operating Revenues	$ 807.4	$ 799.0	$ 245.2	$ 226.0	$1,052.6	$1,025.0
Less: Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	230.9	218.8	108.1	92.3	339.0	311.1
Less: Operating and maintenance	121.2	122.0	39.6	37.3	160.8	159.3
Less: Property and other taxes	109.2	108.1	31.0	30.2	140.2	138.3
Less: Depreciation and depletion	121.3	115.9	24.4	25.0	145.7	140.9
Gross Margin	**224.8**	**234.2**	**42.1**	**41.2**	**266.9**	**275.4**
Operating and maintenance	121.2	122.0	39.6	37.3	160.8	159.3
Property and other taxes	109.2	108.1	31.0	30.2	140.2	138.3
Depreciation and depletion	121.3	115.9	24.4	25.0	145.7	140.9
Utility Margin(1)	**$ 576.5**	**$ 580.2**	**$ 137.1**	**$ 133.7**	**$ 713.6**	**$ 713.9**

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

	Nine Months Ended September 30,			
	2022	2021	Change	% Change
	(dollars in millions)			
Utility Margin				
Electric	$ 576.5	$ 580.2	$ (3.7)	(0.6) %
Natural Gas	137.1	133.7	3.4	2.5
Total Utility Margin(1)	**$ 713.6**	**$ 713.9**	**$ (0.3)**	**0.0 %**

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

Consolidated utility margin for the nine months ended September 30, 2022 was $713.6 million as compared with $713.9 million for the same period in 2021, a decrease of $0.3 million, or less than one percent.

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

Utility Margin Items Impacting Net Income	Utility Margin 2022 vs. 2021	
Lower transmission revenue due to lower transmission demand due to market conditions and lower pricing	$	(5.6)
Less favorable electric QF liability adjustment		(2.8)
Higher non-recoverable Montana electric supply costs		(1.6)
Reduction of rates from the step down of our Montana gas production assets		(0.8)
Higher electric retail volumes		5.6
Higher natural gas retail volumes		2.3
Other		0.6
Change in Utility Margin Items Impacting Net Income		**(2.3)**
Utility Margin Items Offset Within Net Income		
Higher operating expenses recovered in revenue, offset in operating and maintenance expense		2.0
Higher property taxes recovered in revenue, offset in property tax expense		1.9
Higher gas production taxes recovered in revenue, offset in property and other taxes		0.3
Lower revenue from higher production tax credits, offset in income tax expense		(2.2)
Change in Utility Margin Items Offset Within Net Income		**2.0**
Decrease in Consolidated Utility Margin(1)	**$**	**(0.3)**

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

Higher electric retail volumes were driven by customer growth and increased residential and industrial demand as compared to the prior year, partly offset by lower Montana commercial demand. Higher natural gas retail volumes were driven by colder winter weather in Montana and South Dakota, colder spring weather in all jurisdictions, and customer growth, partly offset by warmer winter weather in Nebraska and warmer summer weather in Montana.

The less favorable adjustment to our electric QF liability (unrecoverable costs associated with PURPA contracts as part of a 2002 stipulation with the MPSC and other parties) reflects a $5.1 million gain in 2022, as compared with a $7.9 million gain for the same period in 2021, due to the combination of:

- A $1.8 million favorable reduction in costs for the current contract year to record the annual adjustment for actual output and pricing as compared with a $2.6 million favorable reduction in costs in the prior period;
- A favorable adjustment, decreasing the QF liability by $3.3 million, reflecting annual actual contract price escalation for the 2023-2024 contract year, which was less than previously estimated, partly offset by an increase in estimated contract prices for the 2023-2024 contract year, which is the last year of the contract that contains variable pricing terms. See Critical Accounting Policies and Estimates below for further information regarding our process of estimating the contract price for the 2023-2024 contract year. This is compared to an unfavorable adjustment of $2.1 million in the prior year due to higher actual price escalation; and
- A favorable adjustment in the prior year, decreasing the QF liability by approximately $7.4 million, associated with a one-time clarification in contract term.

	Nine Months Ended September 30,			
	2022	2021	Change	% Change
	(dollars in millions)			
Operating Expenses (excluding fuel, purchased supply and direct transmission expense)				
Operating and maintenance	$ 160.8	$ 159.3	$ 1.5	0.9 %
Administrative and general	87.0	79.6	7.4	9.3
Property and other taxes	140.2	138.3	1.9	1.4
Depreciation and depletion	145.7	140.9	4.8	3.4
Total Operating Expenses (excluding fuel, purchased supply and direct transmission expense)	**$ 533.7**	**$ 518.1**	**$ 15.6**	**3.0 %**

Consolidated operating expenses, excluding fuel, purchased supply and direct transmission expense, were $533.7 million for the nine months ended September 30, 2022, as compared with $518.1 million for the nine months ended September 30, 2021. Primary components of the change include the following (in millions):

	Operating Expenses 2022 vs. 2021	
Operating Expenses (excluding fuel, purchased supply and direct transmission expense) Impacting Net Income		
Higher depreciation expense due to plant additions	$	4.8
Increase in uncollectible accounts due to the prior year collection of previously written off balances		2.2
Higher insurance expense		1.8
Higher technology implementation and maintenance expenses		1.5
Higher travel expenses		1.1
Higher line clearing expenses		0.8
Higher litigation expenses		0.8
Higher labor and benefits(1)		0.2
Prior year write-off of preliminary construction costs		(1.2)
Lower expenses at our electric generation facilities		(0.4)
Other		1.2
Change in Items Impacting Net Income		**12.8**
Operating Expenses Offset Within Net Income		
Higher operating and maintenance expenses recovered in trackers, offset in revenue		2.0
Higher property and other taxes recovered in trackers, offset in revenue		1.9
Higher pension and other postretirement benefits, offset in other income(1)		0.8
Lower non-employee directors deferred compensation recorded within administrative and general expense, offset in other income		(1.9)
Change in Items Offset Within Net Income		**2.8**
Increase in Operating Expenses (excluding fuel, purchased supply and direct transmission expense)	**$**	**15.6**

(1) In order to present the total change in labor and benefits, we have included the change in the non-service cost component of our pension and other postretirement benefits, which is recorded within other income on our Condensed Consolidated Statements of Income. This change is offset within this table as it does not affect our operating expenses.

Consolidated operating income for the nine months ended September 30, 2022 was $179.9 million as compared with $195.7 million in the same period of 2021. This decrease was primarily driven by lower transmission revenue, a less favorable QF liability adjustment as compared to the prior period, higher operating and maintenance costs, higher administrative and general costs, higher depreciation and depletion, and higher uncollectible accounts expense due to the prior year collection of previously written off balances, partly offset by higher electric and natural gas retail volumes.

Consolidated interest expense was $73.1 million for the nine months ended September 30, 2022 as compared with $70.3 million for the same period of 2021. This increase was primarily due to higher interest on borrowings under our revolving credit facilities partly offset by higher capitalization of AFUDC.

Consolidated other income was $11.8 million for the nine months ended September 30, 2022 as compared to $13.9 million during the same period of 2021. This decrease was primarily due to the $2.5 million CREP penalty, which relates to litigation we have been involved in associated with our past progress towards meeting obligations to acquire renewable energy projects as mandated by the recently repealed Montana CREP requirement, and a decrease in the value of deferred shares held in trust for non-employee directors deferred compensation. These decreases are partly offset by a decrease in the non-service component of pension expense and higher capitalization of AFUDC.

Consolidated income tax expense for the nine months ended September 30, 2022 was $2.3 million as compared to $3.9 million in the same period of 2021. Our effective tax rate for the nine months ended September 30, 2022 was 1.9% as compared with 2.8% for the same period in 2021. We expect our effective tax rate to range between 0% to 3% in 2022.

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

	Nine Months Ended September 30,			
	2022		2021	
Income Before Income Taxes	$ 118.6		$ 139.4	
Income tax calculated at federal statutory rate	24.9	21.0 %	29.3	21.0 %
Permanent or flow-through adjustments:				
State income tax, net of federal provisions	1.0	0.8	0.7	0.5
Flow-through repairs deductions	(13.5)	(11.4)	(15.6)	(11.2)
Production tax credits	(8.1)	(6.8)	(8.4)	(6.1)
Income tax return to accrual adjustment	(0.9)	(0.8)	0.4	0.3
Amortization of excess deferred income tax	(0.8)	(0.7)	(0.6)	(0.4)
Share-based compensation	(0.3)	(0.2)	(0.3)	(0.2)
Plant and depreciation of flow-through items	0.4	0.3	(0.8)	(0.6)
Other, net	(0.4)	(0.3)	(0.8)	(0.5)
	(22.6)	(19.1)	(25.4)	(18.2)
Income tax expense	$ 2.3	1.9 %	$ 3.9	2.8 %

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.

ELECTRIC SEGMENT

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

- Retail: Sales of electricity to residential, commercial and industrial customers, and the impact of regulatory mechanisms.
- 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, which is also reflected in fuel, purchased supply and direct transmission expense and therefore has minimal impact on utility margin. The amortization of these amounts are offset in retail revenue.
- Transmission: Reflects transmission revenues regulated by the FERC.
- Wholesale and other are largely utility margin neutral as they are offset by changes in fuel, purchased supply and direct transmission expense.

Three Months Ended September 30, 2022 Compared with the Three Months Ended September 30, 2021

	Revenues		Change		Megawatt Hours (MWH)		Avg. Customer Counts	
	2022	2021	$	%	2022	2021	2022	2021
	(in thousands)							
Montana	$ 85,226	$ 85,539	$ (313)	(0.4) %	702	692	317,274	312,265
South Dakota	18,955	18,882	73	0.4	158	158	51,056	50,756
Residential	**104,181**	**104,421**	**(240)**	**(0.2)**	**860**	**850**	**368,330**	**363,021**
Montana	92,563	95,248	(2,685)	(2.8)	839	847	73,277	71,766
South Dakota	29,093	28,798	295	1.0	297	296	12,949	12,835
Commercial	**121,656**	**124,046**	**(2,390)**	**(1.9)**	**1,136**	**1,143**	**86,226**	**84,601**
Industrial	9,784	9,147	637	7.0	675	611	76	76
Other	12,581	13,089	(508)	(3.9)	85	89	8,266	8,226
Total Retail Electric	**$ 248,202**	**$ 250,703**	**$ (2,501)**	**(1.0)%**	**2,756**	**2,693**	**462,898**	**455,924**
Regulatory amortization	21,805	9,922	11,883	119.8				
Transmission	20,439	25,172	(4,733)	(18.8)				
Wholesale and Other	1,825	1,676	149	8.9				
Total Revenues	**$ 292,271**	**$ 287,473**	**$ 4,798**	**1.7 %**				
Fuel, purchased supply and direct transmission expense(1)	**95,554**	**89,375**	**6,179**	**6.9**				
Utility Margin(2)	**$ 196,717**	**$ 198,098**	**$ (1,381)**	**(0.7)%**				

(1) Exclusive of depreciation and depletion.
(2) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above. Also see "Overall Consolidated Results" above for reconciliation of gross margin to utility margin.

	Cooling Degree Days			2022 as compared with:	
	2022	2021	Historic Average	2021	Historic Average
Montana	562	493	377	14% warmer	49% warmer
South Dakota	811	818	634	1% cooler	28% warmer

	Heating Degree Days			2022 as compared with:	
	2022	2021	Historic Average	2021	Historic Average
Montana(1)	146	251	285	42% warmer	49% warmer
South Dakota	24	23	77	4% cooler	69% warmer

(1) Montana electric and natural gas heating degree days may differ due to differences in service territory.

The following summarizes the components of the changes in electric utility margin for the three months ended September 30, 2022 and 2021 (in millions):

		Utility Margin 2022 vs. 2021
Utility Margin Items Impacting Net Income		
Lower transmission revenue due to lower transmission demand due to market conditions and lower pricing	$	(4.7)
Higher non-recoverable Montana electric supply costs		(1.3)
Higher retail volumes		2.1
Prior year unfavorable QF liability adjustment		1.3
Other		(0.4)
Change in Utility Margin Items Impacting Net Income		(3.0)
Utility Margin Items Offset Within Net Income		
Higher property taxes recovered in revenue, offset in property tax expense		1.8
Lower revenue from higher production tax credits, offset in income tax expense		(0.1)
Lower operating expenses recovered in revenue, offset in operating and maintenance expense		(0.1)
Change in Utility Margin Items Offset Within Net Income		1.6
Decrease in Utility Margin(1)	**$**	**(1.4)**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above. Also see "Overall Consolidated Results" above for reconciliation of gross margin to utility margin.

Higher electric retail volumes were driven by warmer summer weather in Montana and customer growth, partly offset by lower Montana commercial demand.

The prior year unfavorable adjustment to our QF liability (unrecoverable costs associated with PURPA contracts as part of a 2002 stipulation with the MPSC and other parties) is associated with a one-time clarification in contract term in 2021.

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 utility margin. Our wholesale and other revenues are largely utility margin neutral as they are offset by changes in fuel, purchased supply and direct transmission expenses.

Nine Months Ended September 30, 2022 Compared with the Nine Months Ended September 30, 2021

	Revenues		Change		Megawatt Hours (MWH)		Avg. Customer Counts	
	2022	2021	$	%	2022	2021	2022	2021
	(in thousands)							
Montana	$ 252,893	$ 251,443	$ 1,450	0.6 %	2,117	2,067	316,299	311,256
South Dakota	54,978	51,031	3,947	7.7	470	453	50,995	50,765
Residential	**307,871**	**302,474**	**5,397**	**1.8**	**2,587**	**2,520**	**367,294**	**362,021**
Montana	263,424	266,644	(3,220)	(1.2)	2,420	2,398	72,907	71,437
South Dakota	83,172	76,969	6,203	8.1	849	826	12,882	12,787
Commercial	**346,596**	**343,613**	**2,983**	**0.9**	**3,269**	**3,224**	**85,789**	**84,224**
Industrial	28,426	28,086	340	1.2	1,911	1,842	76	77
Other	25,365	26,798	(1,433)	(5.3)	142	155	6,488	6,449
Total Retail Electric	**$ 708,258**	**$ 700,971**	**$ 7,287**	**1.0 %**	**7,909**	**7,741**	**459,647**	**452,771**
Regulatory amortization	36,087	29,913	6,174	20.6				
Transmission	58,135	63,762	(5,627)	(8.8)				
Wholesale and Other	4,935	4,338	597	13.8				
Total Revenues	**$ 807,415**	**$ 798,984**	**$ 8,431**	**1.1 %**				
Fuel, purchased supply and direct transmission expense[(1)]	**230,872**	**218,802**	**12,070**	**5.5**				
Utility Margin[(2)]	**$ 576,543**	**$ 580,182**	**$ (3,639)**	**(0.6)%**				

(1) Exclusive of depreciation and depletion.
(2) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above. Also see "Overall Consolidated Results" above for reconciliation of gross margin to utility margin.

	Cooling Degree Days			2022 as compared with:	
	2022	2021	Historic Average	2021	Historic Average
Montana[(1)]	602	632	443	5% cooler	36% warmer
South Dakota	877	966	706	9% cooler	24% warmer

	Heating Degree Days			2022 as compared with:	
	2022	2021	Historic Average	2021	Historic Average
Montana[(1)]	4,784	4,680	4,679	2% cooler	2% cooler
South Dakota	5,712	5,188	5,690	10% cooler	remained flat

(1) Montana electric and natural gas heating degree days may differ due to differences in service territory.

The following summarizes the components of the changes in electric utility margin for the nine months ended September 30, 2022 and 2021 (in millions):

		Utility Margin 2022 vs. 2021
Utility Margin Items Impacting Net Income		
Lower transmission revenue due to lower transmission demand due to market conditions and lower pricing	$	(5.6)
QF liability adjustment		(2.8)
Higher non-recoverable Montana electric supply costs		(1.6)
Higher retail volumes		5.6
Other		(0.2)
Change in Utility Margin Items Impacting Net Income		(4.6)
Utility Margin Items Offset Within Net Income		
Higher operating expenses recovered in revenue, offset in operating and maintenance expense		1.9
Higher property taxes recovered in revenue, offset in property tax expense		1.2
Lower revenue from higher production tax credits, offset in income tax expense		(2.2)
Change in Utility Margin Items Offset Within Net Income		0.9
Decrease in Utility Margin[(1)]	**$**	**(3.7)**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above. Also see "Overall Consolidated Results" above for reconciliation of gross margin to utility margin.

Higher electric retail volumes were driven by customer growth and increased residential and industrial demand as compared to the prior year, partly offset by lower Montana commercial demand.

The less favorable adjustment to our QF liability (unrecoverable costs associated with PURPA contracts as part of a 2002 stipulation with the MPSC and other parties) reflects a $5.1 million gain in 2022, as compared with a $7.9 million gain for the same period in 2021, due to the combination of:

- A $1.8 million favorable reduction in costs for the current contract year to record the annual adjustment for actual output and pricing as compared with a $2.6 million favorable reduction in costs in the prior period;
- A favorable adjustment, decreasing the QF liability by $3.3 million, reflecting annual actual contract price escalation for the 2023-2024 contract year, which was less than previously estimated, partly offset by an increase in estimated contract prices for the 2023-2024 contract year, which is the last year of the contract that contains variable pricing terms. See Critical Accounting Policies and Estimates below for further information regarding our process of estimating the contract price for the 2023-2024 contract year. This is compared to an unfavorable adjustment of $2.1 million in the prior year due to higher actual price escalation; and
- A favorable adjustment in the prior year, decreasing the QF liability by approximately $7.4 million, associated with a one-time clarification in contract term.

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 utility margin. Our wholesale and other revenues are largely utility margin neutral as they are offset by changes in fuel, purchased supply and direct transmission expenses.

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, and the impact of regulatory mechanisms.
- 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 fuel, purchased supply and direct transmission expenses and therefore has minimal impact on utility margin. The amortization of these amounts are offset in retail revenue.
- Wholesale: Primarily represents transportation and storage for others.

Three Months Ended September 30, 2022 Compared with the Three Months Ended September 30, 2021

	Revenues		Change		Dekatherms (Dkt)		Avg. Customer Counts	
	2022	2021	$	%	2022	2021	2022	2021
	(in thousands)							
Montana	$ 10,774	$ 9,910	$ 864	8.7 %	729	845	181,729	179,571
South Dakota	2,362	2,179	183	8.4	102	106	41,223	40,826
Nebraska	3,228	2,443	785	32.1	138	144	37,522	37,406
Residential	**16,364**	**14,532**	**1,832**	**12.6**	**969**	**1,095**	**260,474**	**257,803**
Montana	7,066	6,110	956	15.6	568	603	25,267	24,872
South Dakota	2,080	1,781	299	16.8	161	179	7,009	6,846
Nebraska	2,321	1,461	860	58.9	145	144	4,946	4,920
Commercial	**11,467**	**9,352**	**2,115**	**22.6**	**874**	**926**	**37,222**	**36,638**
Industrial	117	76	41	53.9	11	8	233	227
Other	222	163	59	36.2	20	18	179	168
Total Retail Gas	**$ 28,170**	**$ 24,123**	**$ 4,047**	**16.8 %**	**1,874**	**2,047**	**298,108**	**294,836**
Regulatory amortization	5,588	5,415	173	3.2				
Wholesale and other	9,040	8,944	96	1.1				
Total Revenues	**$ 42,798**	**$ 38,482**	**$ 4,316**	**11.2 %**				
Fuel, purchased supply and direct transmission expense(1)	**13,367**	**9,284**	**4,083**	**44.0**				
Utility Margin(2)	**$ 29,431**	**$ 29,198**	**$ 233**	**0.8 %**				

(1) Exclusive of depreciation and depletion.
(2) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above. Also see "Overall Consolidated Results" above for reconciliation of gross margin to utility margin.

	Heating Degree Days			2022 as compared with:	
	2022	2021	Historic Average	2021	Historic Average
Montana(1)	180	300	327	40% warmer	45% warmer
South Dakota	24	23	77	4% cooler	69% warmer
Nebraska	9	9	34	remained flat	74% warmer

(1) Montana electric and natural gas heating degree days may differ due to differences in service territory.

The following summarizes the components of the changes in natural gas utility margin for the three months ended September 30, 2022 and 2021:

	Utility Margin 2022 vs. 2021 (in millions)
Utility Margin Items Impacting Net Income	
Lower retail volumes	$ (0.6)
Reduction of rates from the step down of our Montana gas production assets	(0.1)
Other	0.5
Change in Utility Margin Items Impacting Net Income	(0.2)
Utility Margin Items Offset Within Net Income	
Higher property taxes recovered in revenue, offset in property tax expense	0.4
Change in Utility Margin Items Offset Within Net Income	0.4
Increase in Utility Margin[(1)]	**$ 0.2**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above. Also see "Overall Consolidated Results" above for reconciliation of gross margin to utility margin.

Lower retail volumes were driven by warmer summer weather in Montana, partly offset by customer growth.

Our wholesale and other revenues are largely utility margin neutral as they are offset by changes in fuel, purchased supply and direct transmission expenses.

Nine Months Ended September 30, 2022 Compared with the Nine Months Ended September 30, 2021

	Revenues 2022	Revenues 2021	Change $	Change %	Dekatherms (Dkt) 2022	Dekatherms (Dkt) 2021	Avg. Customer Counts 2022	Avg. Customer Counts 2021
	(in thousands)							
Montana	$ 91,669	$ 82,424	$ 9,245	11.2 %	9,469	9,119	181,629	179,340
South Dakota	31,686	18,654	13,032	69.9	2,566	2,248	41,383	40,975
Nebraska	26,028	14,599	11,429	78.3	1,960	1,987	37,634	37,560
Residential	**149,383**	**115,677**	**33,706**	**29.1**	**13,995**	**13,354**	**260,646**	**257,875**
Montana	48,813	42,890	5,923	13.8	5,291	4,977	25,280	24,876
South Dakota	23,030	12,562	10,468	83.3	2,314	2,060	7,026	6,873
Nebraska	16,004	7,740	8,264	106.8	1,411	1,397	4,987	4,953
Commercial	**87,847**	**63,192**	**24,655**	**39.0**	**9,016**	**8,434**	**37,293**	**36,702**
Industrial	890	726	164	22.6	100	88	232	229
Other	1,381	1,007	374	37.1	171	136	177	164
Total Retail Gas	**$ 239,501**	**$ 180,602**	**$ 58,899**	**32.6 %**	**23,282**	**22,012**	**298,348**	**294,970**
Regulatory amortization	(22,188)	17,951	(40,139)	(223.6)				
Wholesale and other	27,826	27,438	388	1.4				
Total Revenues	**$ 245,139**	**$ 225,991**	**$ 19,148**	**8.5 %**				
Fuel, purchased supply and direct transmission expense[1]	**108,122**	**92,335**	**15,787**	**17.1**				
Utility Margin[2]	**$ 137,017**	**$ 133,656**	**$ 3,361**	**2.5 %**				

(1) Exclusive of depreciation and depletion.
(2) Non-GAAP financial measure. See “Non-GAAP Financial Measure” above. Also see "Overall Consolidated Results" above for reconciliation of gross margin to utility margin.

	Heating Degree Days 2022	Heating Degree Days 2021	Heating Degree Days Historic Average	2022 as compared with: 2021	2022 as compared with: Historic Average
Montana[1]	4,926	4,767	4,812	3% cooler	2% cooler
South Dakota	5,712	5,188	5,690	10% cooler	remained flat
Nebraska	4,239	4,432	4,495	4% warmer	6% warmer

(1) Montana electric and natural gas heating degree days may differ due to differences in service territory.

The following summarizes the components of the changes in natural gas utility margin for the nine months ended September 30, 2022 and 2021:

		Utility Margin 2022 vs. 2021 (in millions)
Utility Margin Items Impacting Net Income		
Higher retail volumes	$	2.3
Reduction of rates from the step down of our Montana gas production assets		(0.8)
Other		0.8
Change in Utility Margin Items Impacting Net Income		2.3
Utility Margin Items Offset Within Net Income		
Higher property taxes recovered in revenue, offset in property tax expense		0.7
Higher gas production taxes recovered in revenue, offset in property and other taxes		0.3
Higher operating expenses recovered in revenue, offset in operating and maintenance expense		0.1
Change in Utility Margin Items Offset Within Net Income		1.1
Increase in Utility Margin(1)	**$**	**3.4**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above. Also see "Overall Consolidated Results" above for reconciliation of gross margin to utility margin.

Higher retail volumes were driven by colder winter weather in Montana and South Dakota, colder spring weather in all jurisdictions, and customer growth, partly offset by warmer winter weather in Nebraska and warmer summer weather in Montana.

Our wholesale and other revenues are largely utility margin neutral as they are offset by changes in fuel, purchased supply and direct transmission expenses.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

We require liquidity to support and grow our business, and use our liquidity for working capital needs, capital expenditures, investments in or acquisitions of assets, and to repay debt. We believe our cash flows from operations, existing borrowing capacity, debt and equity issuances and future utility rate increases should be sufficient to fund our operations, service existing debt, pay dividends, and fund capital expenditures (excluding strategic growth opportunities). We plan to maintain a 50 - 55 percent debt to total capital ratio excluding finance leases, and expect to continue targeting 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.

As of September 30, 2022, our total net liquidity was approximately $74.1 million, including $9.1 million of cash and $65.0 million of revolving credit facility availability with no letters of credit outstanding. In addition, our liquidity was further enhanced by the forward equity sale agreements noted below, which could have been physically settled with common shares in exchange for cash of approximately $96.9 million.

Cash Flows

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

	Nine Months Ended September 30,	
	2022	**2021**
Operating Activities		
Net income	$ 116.3	$ 135.5
Non-cash adjustments to net income	132.5	148.7
Changes in working capital	72.3	(31.0)
Other noncurrent assets and liabilities	(11.8)	(31.6)
Cash Provided by Operating Activities	**309.3**	**221.6**
Investing Activities		
Property, plant and equipment additions	(386.4)	(311.2)
Investment in equity securities	(0.9)	(0.6)
Cash Used in Investing Activities	**(387.3)**	**(311.8)**
Financing Activities		
Proceeds from issuance of common stock, net of issuance costs	179.9	121.1
Issuance of long-term debt, net	—	99.9
Repayments of short-term borrowings	—	(100.0)
Line of credit borrowings, net	12.0	73.0
Dividends on common stock	(103.0)	(95.1)
Other financing activities, net	(1.0)	(1.6)
Cash Provided by Financing Activities	**87.9**	**97.3**
Increase in Cash, Cash Equivalents, and Restricted Cash	**9.9**	**7.1**
Cash, Cash Equivalents, and Restricted Cash, beginning of period	18.8	17.1
Cash, Cash Equivalents, and Restricted Cash, end of period	**$ 28.7**	**$ 24.2**

Operating Activities

As of September 30, 2022, cash, cash equivalents, and restricted cash were $28.7 million as compared with $18.8 million as of December 31, 2021 and $24.2 million as of September 30, 2021. Cash provided by operating activities totaled $309.3 million for the nine months ended September 30, 2022 as compared with $221.6 million during the nine months ended September 30, 2021. As shown in the table below, this increase in operating cash flows is primarily due to a $76.5 million improvement in net cash outflows for uncollected energy supply costs during the nine months ended September 30, 2022, compared to the nine months ended September 30, 2021. The 2021 period includes costs incurred during a February 2021 prolonged cold weather event and a significant under-collected position of Montana's PCCAM for the July 2020 - June 2021 period. While we have various regulatory mechanisms that supported our recovery of much of the 2021 under-collected position during 2022, higher overall market prices during 2022 have resulted in new under-collected energy supply costs that more than offset the recovery of the prior year balances. In addition, we issued a refund of approximately $20.5 million to our FERC regulated wholesale customers in the prior period.

Under-collected supply costs (in millions)

	December 31,	September 30,	Net cash outflows
2021	$ 3.9	$ 84.5	$ 80.6
2022	$ 97.8	$ 101.9	$ 4.1
		Year-to-date improvement	$ 76.5

As of September 30, 2022, our uncollected energy supply cost balance includes $52.7 million related to the July 2021 - June 2022 PCCAM period, which has been included in customer rates for recovery beginning October 1, 2022. The balance also includes an additional $28.6 million under-collection related to the PCCAM period that began on July 1, 2022. This under-collection occurred relative to a PCCAM Base of $138.7 million, which was approved in 2019. As part of our Montana general rate review we have requested an increase to the PCCAM Base to more accurately reflect the current higher overall market energy prices. On September 28, 2022, the MPSC approved our request for interim rates, including a $61.1 million increase to the PCCAM Base, which became effective in customer rates on October 1, 2022.

Assuming a favorable final outcome on our Montana rate review and PCCAM mechanism requests we anticipate continued improvements in our cash flows from operations. However, unfavorable results in our Montana rate review, and continued higher overall market prices, which could be further exacerbated by extreme weather events, could create additional costs with deferred recovery that would offset these anticipated cash flow improvements.

Investing Activities

Cash used in investing activities totaled $387.3 million during the nine months ended September 30, 2022, as compared with $311.8 million during the nine months ended September 30, 2021. Plant additions during the first nine months of 2022 include maintenance additions of approximately $218.0 million and capacity related capital expenditures of $168.4 million. Plant additions during the first nine months of 2021 included maintenance additions of approximately $230.7 million and capacity related capital expenditures of approximately $80.5 million.

Financing Activities

Cash provided by financing activities totaled $87.9 million during the nine months ended September 30, 2022 as compared with $97.3 million during the nine months ended September 30, 2021. During the nine months ended September 30, 2022, cash provided by financing activities reflects proceeds received from the issuance of common stock of $179.9 million and net issuances under our revolving lines of credit of $12.0 million, offset in part by payment of dividends of $103.0 million. During the nine months ended September 30, 2021, cash provided by financing activities reflects proceeds received from the issuance of common stock pursuant to our ATM program of $121.1 million, net proceeds from the issuance of debt of $99.9 million, and net issuances under our revolving lines of credit of $73.0 million, offset in part by repayments of our short-term borrowings of $100.0 million and payment of dividends of $95.1 million.

Cash Requirements and Capital Resources

We believe our cash flows from operations, existing borrowing capacity, debt and equity issuances and future rate increases should be sufficient to satisfy our material cash requirements over the short-term and the long-term. As a rate-regulated utility our customer rates are generally structured to recover expected operating costs, with an opportunity to earn a return on our invested capital. This structure supports recovery for many of our operating expenses, although there are situations where the timing of our cash outlays results in increased working capital requirements. Due to the seasonality of our utility business, our short-term working capital requirements typically peak during the coldest winter months and warmest summer months when we cover the lag between when purchasing energy supplies and when customers pay for these costs. Our credit facilities may also be utilized for funding cash requirements during seasonally active construction periods, with peak activity during warmer months. Our cash requirements also include a variety of contractual obligations as outlined below in the "Contractual Obligations and Other Commitments" section.

Our material cash requirements are also related to investment in our business through our capital expenditure program. Our estimated capital expenditures are discussed in our Annual Report on Form 10-K for the year ended December 31, 2021 within the Management's Discussion and Analysis of Financial Condition and Results of Operations under the "Significant Infrastructure Investments and Initiatives" section. As of September 30, 2022, there have been no material changes in our estimated capital expenditures. The actual amount of capital expenditures is subject to certain factors including the impact that a material change in operations or available financing could impact our current liquidity and ability to fund capital resource requirements. Events such as these could cause us to defer a portion of our planned capital expenditures, as necessary. To fund our strategic growth opportunities, we evaluate the additional capital need in balance with, debt capacity and equity issuances that would be intended to allow us to maintain investment grade ratings.

Credit Facilities

Liquidity is generally provided by internal cash flows and the use of our unsecured revolving credit facilities. This includes the $425 million Credit Facility and a $25 million revolving credit facility to provide swingline borrowing capability. We utilize availability under our revolving credit facilities to manage our cash flows due to the seasonality of our business and to fund capital investment. Cash on hand in excess of current operating requirements is generally used to invest in our business and reduce borrowings.

Our $425 million Credit Facility was amended and restated in May 2022 and has a maturity date of May 18, 2027. Our $25 million credit facility was entered into in March 2018 and has a current maturity date of March 27, 2024.

As of September 30, 2022 and 2021 the outstanding balances on our credit facilities were $385.0 million and $295.0 million, respectively. As of October 21, 2022, our availability under our revolving credit facilities was approximately $67.0 million, and there were no letters of credit outstanding.

Long-term Debt and Equity

We generally issue long-term debt to refinance other long-term debt maturities and borrowings under our revolving credit facilities, as well as to fund long-term capital investments and strategic opportunities. During 2022, we have not issued new long-term debt and do not have any scheduled long-term debt maturities.

We may issue equity securities to fund long-term investment in our business. We evaluate our equity issuance needs to support our plan to maintain a 50 - 55 percent debt to total capital ratio excluding finance leases.

As further discussed in Note 5 - Financing Activities to the Financial Statements included herein, in November 2021 we entered into forward equity agreements in connection with a completed $373.8 million public offering of approximately 7.0 million shares of our common stock. Of the total 7.0 million shares of the common stock offered, we initially sold 1.4 million shares, for $75.0 million in gross proceeds, directly to the underwriters in the offering, with cash proceeds received at closing.

On June 24, 2022, we partially settled the forward sale agreement by physically delivering 2.0 million shares of common stock in exchange for cash proceeds of $99.9 million, net of issuance costs. Additionally, on September 21, 2022, we partially settled the forward sale agreement by physically delivering 1.6 million shares of common stock in exchange for cash proceeds of $80.0 million, net of issuance costs. The proceeds were used to pay down borrowings under our revolving credit facility and for other general corporate purposes.

At September 30, 2022, the forward agreements could have been settled with physical delivery of approximately 2.0 million common shares to the banking counterparty in exchange for cash of $96.9 million. The forward agreements could have also been settled at September 30, 2022, with delivery of $10.3 million of cash or approximately 0.2 million shares of common stock to the counterparty, if we unilaterally elected to net cash or net share settlement, respectively. We may settle the agreements at any time up to the maturity date of February 28, 2023.

Credit Ratings

In general, less favorable credit ratings make debt financing more costly and more difficult to obtain on terms that are favorable to us and our customers, may impact our trade credit availability, and could result in the need to issue additional equity securities. Fitch Ratings (Fitch), Moody's Investors Service (Moody's), and S&P Global Ratings (S&P) are independent credit-rating agencies that rate our debt securities. These ratings indicate the agencies' assessment of our ability to pay interest and principal when due on our debt. As of October 21, 2022, our current ratings with these agencies are as follows:

	Senior Secured Rating	Senior Unsecured Rating	Commercial Paper	Outlook
Fitch[(1)]	A-	BBB+	F3	Stable
Moody's[(2)]	A3	Baa2	Prime-2	Stable
S&P	A-	BBB	A-2	Stable

(1) On March 24, 2022, Fitch downgraded our senior unsecured and secured ratings to 'BBB+' from 'A-' and to 'A-' from 'A', respectively, and our Short-Term IDR and CP rating to 'F3' from 'F2'.
(2) On May 11, 2022, Moody's affirmed our ratings and revised our outlook from negative to stable.

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

Contractual Obligations and Other Commitments

We have a variety of contractual obligations and other commitments that require payment of cash at certain specified periods. The following table summarizes our contractual cash obligations and commitments as of September 30, 2022.

	Total	2022	2023	2024	2025	2026	Thereafter
			(in thousands)				
Long-term debt[(1)]	$ 2,564,660	$ —	$ 144,660	$ 100,000	$ 300,000	$ 105,000	$ 1,915,000
Finance leases	12,642	745	3,098	3,338	3,596	1,865	—
Estimated pension and other postretirement obligations[(2)]	49,424	3,394	11,658	11,658	11,357	11,357	N/A
Qualifying facilities liability[(3)]	405,438	19,343	80,750	76,393	60,360	55,393	113,199
Supply and capacity contracts[(4)]	2,628,346	119,602	373,465	225,673	222,247	181,746	1,505,613
Contractual interest payments on debt[(5)]	1,482,156	25,075	95,645	96,645	87,675	81,585	1,095,531
Commitments for significant capital projects[(6)]	245,636	69,901	90,664	72,584	12,487	—	—
Total Commitments[(7)]	$ 7,388,302	$ 238,060	$ 799,940	$ 586,291	$ 697,722	$ 436,946	$ 4,629,343

(1) Represents cash payments for long-term debt and excludes $11.2 million of debt discounts and debt issuance costs, net.
(2) We estimate cash obligations related to our pension and other postretirement benefit programs for five years, as it is not practicable to estimate thereafter. Pension and postretirement benefit estimates reflect our expected cash contributions, which may be in excess of minimum funding requirements.
(3) Certain QFs require us to purchase minimum amounts of energy at prices ranging from $64 to $136 per MWH through 2029. Our estimated gross contractual obligation related to these QFs is approximately $405.4 million. A portion of the costs incurred to purchase this energy is recoverable through rates authorized by the MPSC, totaling approximately $342.9 million.
(4) We have entered into various purchase commitments, largely purchased power, electric transmission, coal and natural gas supply and natural gas transportation contracts. These commitments range from one to 26 years and exclude contract payments associated with the Beartooth Battery agreement, which is subject to approval by the MPSC. The energy supply costs incurred under these contracts are generally recoverable through rate mechanisms approved by the MPSC.
(5) Contractual interest payments include our revolving credit facilities, which have a variable interest rate. We have assumed an average interest rate of 4.39 percent on the outstanding balance through maturity of the facilities.
(6) Represents significant firm purchase commitments for construction of planned capital projects.
(7) The table above excludes potential tax payments related to uncertain tax positions as they are not practicable to estimate. Additionally, the table above excludes reserves for environmental remediation (See Note 10 - Commitments and Contingencies) and asset retirement obligations as the amount and timing of cash payments may be uncertain.

Other Obligations - As a co-owner of Colstrip, we provided surety bonds of approximately $17.3 million and $19.9 million as of September 30, 2022 and December 31, 2021, respectively, to ensure the operation and maintenance of remedial and closure actions are carried out related to the Administrative Order on Consent Regarding Impacts Related to Wastewater Facilities Comprising the Closed-Loop System at Colstrip Steam Electric Stations, Colstrip Montana (the AOC) as required by the MDEQ. As costs are incurred under the AOC, the surety bonds will be reduced.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

We continually evaluate the appropriateness of our estimates and assumptions. Actual results could differ from those estimates. We consider an estimate to be critical if it is material to the Financial Statements and it requires assumptions to be made that were uncertain at the time the estimate was made and changes in the estimate are reasonably likely to occur from period to period. This includes the accounting for the following: regulatory assets and liabilities, pension and postretirement benefit plans, income taxes and qualifying facilities liability. These policies were disclosed in Management's Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report on Form 10-K for the year ended December 31, 2021. As of September 30, 2022, there have been no material changes in these policies, with the exception of the qualifying facilities liability. In the second quarter of 2022 we modified our approach to estimate the annual escalation of the contract that contains variable pricing terms as there is only one year of pricing variability remaining to estimate. We previously utilized a 3 percent escalation rate, reflecting the long-term nature of the contract. Our modified policy and estimate is as follows:

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 $64 to $136 per MWH through June 2029. Our estimated gross contractual obligation is approximately $405.4 million through June 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $342.9 million through June 2029. We maintain an electric QF liability based on the net present value (discounted at 7.75 percent) 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 for each reporting period, we compare our assumptions to actual results and make adjustments as necessary for that period.

One of the QF contracts included in the 2002 stipulation contains variable pricing terms, which exposes us to price escalation risks. The actual contract pricing is derived from numerous internal and external data points, and is set each year through a filing with the MPSC. The annual contract pricing changes could significantly impact the liability and our results of operations, to the extent the actual price set differs from our previous estimates. The impact of historically high inflation levels experienced during 2021 and the first half of 2022 has resulted in a 20 percent decrease in the actual contract price for the 2022-2023 contract year. This contract expires after the 2023-2024 contract year. The estimated annual escalation rate for this contract is a key assumption in determining the electric QF liability. We have estimated pricing for the 2023-2024 contract year based on a combination of historical actual results and available market data and the associated impact in the numerous internal and external data points for contract pricing, resulting in an approximate 40 percent increase, reversing from the lower 2022-2023 actual contract pricing. A 10 percent change in the estimated 2023-2024 contract pricing would have impacted our pre-tax results of operations by +/- $2.7 million.

See Note 18 - Commitments and Contingencies to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2021 for further discussion.

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 counterparty credit exposure. We have established comprehensive risk management policies and procedures to manage these market risks. There have been no material changes in our market risks as disclosed in our Annual Report on Form 10-K for the year ended December 31, 2021.

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 were effective.

Changes in Internal Control Over Financial Reporting

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

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

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

ITEM 1A. RISK FACTORS

You should carefully consider the risk factors described below, as well as all other information available to you, before making an investment in our common stock or other securities. Although the risks are organized by heading, and each risk is described separately, many of the risks are interrelated. You should not interpret the disclosure of any risk factor to imply that the risk has not already materialized. While we believe we have identified and discussed below the key risk factors affecting our business, there may be additional risks and uncertainties that are not presently known or that are not currently believed to be significant that may adversely affect our business, financial condition, results of operations or cash flows in the future.

Regulatory, Legislative and Legal Risks

Our profitability is dependent on our ability to recover the costs of providing energy and utility services to our customers and earn a return on our capital investment in our utility operations. We are subject to potential unfavorable litigation, and 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 or collect them in a timely manner, which could adversely impact our results of operations and liquidity.

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

In addition to rate reviews, our cost tracking mechanisms are a significant component of how we recover our costs. Trackers can also be highly contested dockets and, as with a rate review, there is no guarantee that the applicable regulatory commission will approve our request to recover costs. For example, we have received unfavorable rulings from the MPSC including an order issued on December 2, 2021, in which the MPSC rejected our request to reset the PCCAM Base revenue amount outside of a formal rate review, which means that we will likely continue to under-collect our power costs until we are allowed to update the PCCAM Base in a rate review. While the MPSC approved Staff's recommended interim rate increase which included the majority of our PCCAM Base request ($68.1 million) under our 2022 Montana rate review filing, this interim increase is subject to refund until a final order is approved in the docket. There can be no assurance that the MPSC will allow recovery of costs in the future, which could have a material adverse effect on our financial results.

Rate regulation is premised on providing an opportunity to earn a reasonable rate of return on invested capital. 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 result in rates that allow us the opportunity to earn our authorized return or provide for timely and full recovery of such costs. In addition, each regulatory commission sets rates based in part upon their acceptance of an allocated share of total utility costs. When commissions adopt different methods to calculate inter-jurisdictional cost allocations, some costs may not be recovered. For instance, our Montana electric utility is regulated by the MPSC and the FERC. Differing schedules and regulatory practices between the MPSC and FERC expose us to the risk that we may not recover our costs due to timing of filings, specific calculations and issues such as cost allocation methodologies. Thus, the rates we are allowed to charge may or may not match our costs at any given time. Adverse regulatory rulings could have an adverse impact on our results of operations and materially affect our ability to meet our financial obligations, including debt payments and the payment of dividends on our common stock.

Before we added Colstrip Unit 4, Dave Gates Generating Station, hydroelectric and Spion Kop electric generation resources to our electric generation supply portfolio, we received a determination from the MPSC that these acquisitions were in the public interest and approval for cost recovery, subject to a prudence review. This advance approval process is established in Montana's "preapproval" statute. On May 28, 2021, a non-profit environmental advocacy organization, together with three individuals, filed suit in Montana District Court (Missoula) seeking a declaratory judgement that the Montana preapproval statute is unconstitutional. The Court issued its Order on May 6, 2022, concluding that the preapproval statute violates the

Montana Constitution, and NorthWestern appealed that decision on June 17, 2022 to the Montana Supreme Court. If the preapproval statute is found unconstitutional, there will be no explicit statutory mechanism that facilitates advanced approval of generating resource selection.

We are also at risk of unfavorable litigation outcomes. We are constructing the Yellowstone County Generating Station in Montana consistent with the outcome of our last integrated resource plan detailing the need for long duration capacity resources. On October 21, 2021, the MEIC and the Sierra Club filed a lawsuit in Montana District Court (Yellowstone County), against the Montana Department of Environmental Quality (MDEQ) and us, alleging that the environmental review conducted prior to issuance of the project's air quality permit was inadequate. The Montana District Court judge held oral argument on June 20, 2022, and we expect a decision during the fourth quarter of 2022. An adverse decision could delay this project for some time if the Court vacates the air quality permit. Vacation of the air quality permit could prolong construction and jeopardize our ability to provide service to Montana customers at peak times, and could result in an increase in costs. The Yellowstone Generating Station construction could also be delayed by recently filed litigation involving zoning. On October 14, 2022 the Thiel Road Coalition, a group of individuals residing in the general area where the Yellowstone County Generating Station is being constructed, along with Northern Plains Resource Council and the MEIC, filed a complaint in Montana District Court (Yellowstone County) against the City of Laurel, Yellowstone County, and NorthWestern. The plaintiffs seek a declaratory judgment that (1) the City of Laurel maintains zoning jurisdiction over the site on which NorthWestern is constructing the plant; and (2) in the alternative, that the County maintains zoning jurisdiction over the site.

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

We are subject to regulations under a wide variety of U.S. federal and state regulations and policies. Regulation affects almost every aspect of our business. Changes to federal and state laws and regulations are continuous and ongoing and the federal administration, the U.S. Congress, state legislatures and state administrations may enact and implement new laws and regulations that could adversely and materially affect us. There can be no assurance that laws, regulations and policies will not be changed in ways that result in significant impacts to our business. For example, legislation and regulations may be enacted that require or facilitate alternative generation or storage which, in turn, could result in customers using less of our energy or facilities which could reduce our revenues and our growth opportunities. We cannot predict future changes in laws and regulations, how they will be implemented and interpreted, or the ultimate effect that this changing environment will have on us. Any changes may have a material adverse effect on our financial condition, results of operations, and cash flows.

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

Our operations are subject to laws and regulations imposed by federal, state and local government authorities regarding energy policy, permitting/siting for energy projects, climate change, the environment, air and water quality, GHG emissions, protection of natural resources, migratory birds and other wildlife, solid waste disposal, coal ash and other environmental considerations. We believe that we are in compliance with environmental regulatory requirements.

However, laws and regulations to which we must adhere change, and the Biden Administration’s agenda represents a significant shift in environmental and energy policy, focusing on reducing GHG emissions and addressing climate change issues. This new direction is reflected in several Executive Orders that President Biden issued in January 2021 and subsequent executive actions that have been undertaken, such as methane emission regulations recently proposed by the EPA or federally driven initiatives to promote electrification over the use of natural gas for domestic purposes. Together, these orders and regulatory proposals reflect climate change issues and GHG reductions as central areas of focus for domestic and international regulations, orders and policies. In addition, a parallel focus on reducing GHG emissions is reflected in legislation introduced in Congress. Representative examples include legislation introduced in March 2021 in the U.S. House of Representatives, called the CLEAN Future Act, tax reforms, the Clean Electricity Performance Program, Build Back Better Act and the recently enacted Inflation Reduction Act of 2022 that imposes a methane fee on natural gas emissions among a number of new clean energy initiatives. We expect other legislation to be introduced and considered by the U.S. House and the U.S. Senate focusing on GHG emission reduction, environmental and energy policy.

These initiatives could lead to new and revised energy and environmental laws and regulations, including tax reforms relating to energy and environmental issues. Any such changes, as well as any enforcement actions or judicial decisions 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.

Although previous attempts by the EPA to regulate GHG emissions from coal-fired plants have not succeeded, it is expected that the Biden Administration and/or the U.S. Congress will develop alternative plans for reducing GHG emissions from coal-fired plants and methane emissions from natural gas operations. As GHG and/or methane regulations are implemented, it could result in additional compliance costs that could affect our future results of operations and financial position if such costs are not recovered through regulated rates. Complying with the CO_2 emission performance standards, and with other future environmental rules, may make it economically impractical to continue operating all or a portion of our jointly owned facilities or for individual owners to participate in their proportionate ownership of the coal-fired generating units. This could lead to significant impacts to customer rates for recovery of plant improvements and / or closure related costs and costs to procure replacement power. In addition, these changes could impact system reliability due to changes in generation sources.

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. Certain environmental laws and regulations also 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 damage 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.

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

While a majority of our Company-wide electric supply portfolio is carbon-free, it does include fossil-fuel resources. Environmental advocacy groups, certain investors and other third parties oppose the operation of fossil-fuel generation, expressing concerns about the environmental and climate-related impacts from fossil fuels. This opposition may increase in scope and frequency depending on a number of variables, including the course of Federal and State laws and environmental regulations and the financial resources devoted to opposition efforts. These risks include litigation against us due to GHG or other emissions or coal combustion residuals disposal and storage; activist shareholder proposals; and increased activism before our regulators. We cannot predict the effect that any such opposition may have on our ability to operate and recover the costs of our generating facilities. In addition, defense costs associated with litigation can be significant and an adverse outcome could require substantial capital expenditures and could possibly require payment of substantial penalties or damages. Such payments or expenditures could affect results of operations, financial condition or cash flows if such costs are not recovered through regulated rates.

Early closure of our generation facilities due to economic conditions, environmental regulations and / or litigation could result in regulatory impairments, increased cost of operations and inability to serve our customers in periods of peak demand. If recovery of our remaining investment in such facilities and the costs associated with early closure, including decommissioning, remediation, reclamation, and restoration are not recovered from customers, it could have a material adverse impact on our results of operations.

Colstrip - As part of the settlement of litigation brought by the Sierra Club and the MEIC against the owners and operator of Colstrip, the owners of Units 1 and 2 agreed to shut down those units no later than July 2022. In January 2020, the owners of Units 1 and 2 closed those two units. We do not have ownership in Units 1 and 2, and decisions regarding those units, including their shut down, were made by their respective owners. The six owners of Units 3 and 4 currently share the operating costs pursuant to the terms of the O&O Agreement. Costs of common facilities were historically shared among the owners of all four units. With the closure of Units 1 and 2, we are incurring additional operating costs with respect to our interest in Unit 4 and may experience a negative impact on our transmission revenue due to reduced amounts of energy transmitted across our transmission lines.

The remaining depreciable life of our investment in Colstrip Unit 4 is through 2042. Recovery of costs associated with the closure of the facility is subject to MPSC approval. Three of the joint owners of Units 3 and 4 are subject to regulation in Washington and in May 2019, the Washington state legislature enacted a statute mandating Washington electric utilities to "eliminate coal-fired resources from [their] allocation of electricity" on or before December 31, 2025, after which date they may no longer include their share of coal-fired resources in their regulated electric supply portfolio. Talen and Puget Sound Energy (Puget), a co-owner of Colstrip, have entered into a transaction in which Puget will transfer its 25% Project Share in Units 3 and 4 to Talen. The anticipated closing date of the transaction is December 31, 2025. On September 12, 2022, Puget issued a notice of the transaction, triggering a 90 day timeframe in which we, or other co-owners could exercise rights of first refusal arising under the O&O Agreement. We are currently evaluating the proposed transaction, the potential exercise of our right of first refusal and the uncertainty and risks concerning the same.

While we believe closure requires each owner’s consent, there are differences among the owners as to this issue under the O&O Agreement. On March 12, 2021, we initiated the Arbitration under the O&O Agreement, which seeks to resolve the primary issue of whether closure of Units 3 and 4 can be accomplished without each joint owner's consent and to clarify the obligations of the joint owners to continue to fund operations until all joint owners agree on closure. The Arbitration, which has been delayed by legal challenges and the impact of the Talen bankruptcy, remains pending.

The closure by third parties of Billings area generation (Corette) and Colstrip Units 1 and 2 reducing supply, together with increased customer load and the lack of dispatchable replacement generation in eastern Montana, has accelerated concerns about potential difficulties in physically serving parts of Montana including the Billings area. We are executing on multi-year plans for upgrades to the Billings area substations and other delivery infrastructure, but the addition of dispatchable generation in the area is also critical to reliable service in eastern Montana.

Increased risks of regulatory penalties could negatively impact our business.

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

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

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

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

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

Operational Risks

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

Inherent in our electric transmission and distribution and natural gas transmission and distribution operations are a variety of hazards and operating risks, such as breakdown or failure of equipment or processes, interruptions in fuel supply, supply chain interruptions, labor disputes, operator error, and catastrophic events such as fires, electric contacts, leaks, explosions, floods and intentional acts of destruction. For our natural gas lines located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the level of potential damages resulting from these risks could be significant. These risks could cause a loss of human life, facility shutdown or significant damage to property, loss of customer load, environmental pollution, impairment of our operations, and substantial financial losses to us and others.

During peak-load periods our electric and natural gas systems in Montana are constrained. These constraints limit our ability to transmit electric energy within Montana and access electric energy from outside the service area. Our electric transmission facilities are also interconnected with those of third parties, and thus operation of these facilities could be adversely affected by unexpected or uncontrollable events. Our natural gas system is also constrained, which limits our on-system deliverability and the ability to transport gas. We are similarly exposed to risk of interconnection with third-party pipelines and are dependent upon their operation to serve customers. These transmission constraints and events could result in failure to provide reliable service to customers due to the inability to deliver energy supply resources, or could result in significant cost increases due to the inability to access lower cost sources of energy supply.

Our electric distribution and transmission lines and facilities are exposed to many threats that may impact our infrastructure, as discussed above. These include severe weather, along with accidental and intentional acts that may cause our lines to fail.

Fire risk is significant in the western United States, including in our service territory. Various factors in recent years have contributed to increasing fire risk including dead and dying trees, warmer air temperatures, drought, wind, forest management practices, and land management practices. These factors increase the risk of a fire in both forests and grasslands. In forested areas, this issue has been heightened by mountain pine beetle and other infestations weakening and killing trees in our service territory. Worsening conditions as a result of climate change may increase the likelihood and magnitude of damages that may be caused by fires. Residential and commercial development into the wildland-urban interface has also led to an increasing trend in the degree of destruction from wildfires.

Fires alleged to have been caused by our equipment potentially expose us to significant penalties and/or damage awards based on claims of strict liability, negligence, gross negligence, inverse condemnation, nuisance, trespass and others. Our equipment has been alleged to be involved in igniting wildfires although none have had a material adverse effect on our financial condition or results of operations. In November 2021, during high wind conditions, one of our electric lines sparked a grassland fire west of Denton, Montana. The fire burned across approximately 18 miles of grassland to the town of Denton where the fire ignited a grain elevator and burned over 25 homes and structures. There was no loss of life or reported injuries. We have fire insurance and, at this time, expect any claims arising from the Denton fire over our insurance retention to be covered by insurance.

For our electric generating facilities, operational risks include facility shutdowns due to breakdown or failure of equipment or processes, interruptions in fuel supply, labor disputes, operator error, catastrophic events such as fires, explosions, floods, and intentional acts of destruction or other similar occurrences affecting the electric generating facilities; and operational changes necessitated by environmental legislation, litigation or regulation. The loss of a major electric generating facility would require us to find other sources of supply or ancillary services, if available, and expose us to higher purchased power costs and potential litigation which may not be recovered from customers. In this regard,a Federal District Court for the District of Montana recently ruled that the Office of Surface Mining did not analyze, or inadequately analyzed, several types of impacts associated with the issuance of a permit for mining a new area at the Rosebud Mine in Montana, which supplies coal to Colstrip and contains significant quantities of coal. The District Court ordered the Office of Surface Mining to correct these deficiencies within 19 months. In the meantime, mining in this area continues. Even without this permit, we believe there is adequate coal to meet our Colstrip Unit 4 operational needs through the current coal supply contract period, which ends on December 31, 2025. In order to operate the Colstrip facility through its currently identified retirement date of 2042, it will be necessary to identify and contract for coal supply subsequent to expiration of current contract.

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.

We may have difficulty cost-effectively completing certain operations activities and construction projects due to inflationary pressures or if our third-party business partners are unable to deliver ordered supplies or complete contracted services timely, including workforce shortages or macro supply chain disruptions.

We place significant reliance on our third-party business partners to supply materials, equipment and labor necessary for us to operate our utility and reliably serve current customers and future customers. As a result of current macroeconomic conditions, both nationally and globally, we have recently experienced issues with our supply chain for materials and components used in our operations and capital project construction activities. Issues include higher prices, scarcities/shortages, longer fulfillment times for orders from our suppliers, workforce availability, and wage increases. Should these economic conditions and issues continue, we could have difficulty completing the operations activities necessary to serve our customers safely and reliably, and/or achieving our capital investment program, which ultimately could result in higher customer utility rates, longer outages, and could have a material adverse impact on our business, financial condition and operations. During the third quarter of 2021, we discontinued our plans to build a 30-40 MW electric generation plant near Aberdeen, South Dakota as a result of significant increases in estimated construction cost as a result of global supply chain challenges, and recorded a $1.6 million pre-tax charge for the write-off of preliminary construction costs.

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

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

Security threats continue to evolve and transform. The risk of cyber-based attacks is heightened due to recent geopolitical events as well as employees working and accessing our technology infrastructure remotely as a result of the COVID-19 pandemic or part of a hybrid workforce. 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, to confidential data, or to disrupt operations. With the continuing rise in ransomware and other cyber-based threats we have been analyzing our technology platforms and monitoring for signs of potential intrusions. We have also been reaching out to our vendors, suppliers and contractors requesting that they take appropriate measures. None of these attempts has individually or in the aggregate resulted in a security incident with a material impact on our financial condition or results of operations. However, despite implementation of security and control measures, there can be no assurance that we will be able to prevent the unauthorized access of our systems and data, or the disruption of our operations, either of which could have a material impact.

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

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

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.

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 ability to manage our operational requirements to serve our customers, and ultimately adversely affect our results of operations and liquidity.

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

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

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, especially those of prolonged duration, create high energy demand on our own and/or other systems and increase the risk we may be unable to reliably serve customers, causing brownouts and/or blackouts of our electric systems, and loss of gas supply. Risk of losing electricity or gas supply during extreme weather carries significant consequences as without our services our customers may be subjected to dire circumstances. Additionally, extreme weather conditions may raise market prices as we buy short-term energy to serve our own system. To the extent the frequency of extreme weather events increase, this could increase our cost of providing service. In addition, we may not recover all costs related to mitigating these physical and financial risks.

Our electric and natural gas portfolios rely significantly on market purchases. This exposure adversely affects our ability to manage our operational requirements to reliably serve our customers, while exposing us to market volatility, which ultimately could adversely affect our results of operations and liquidity.

We are obligated to supply power to retail customers and certain wholesale customers and procure natural gas to supply fuel for our natural gas fired generation. Our need to acquire flexible energy supply and capacity in the market to meet our electric and natural gas load serving obligations exposes us to certain risks including the ability to reliably serve customers and significant uncertainty in the cost of supply, which may not be recoverable. We rely upon a combination of base-load supply from our owned generation and market purchases to serve customers. The accredited capacity of our Montana portfolio of owned and long-term contracted electric generation resources covers 70 percent of our recent peak electric requirements, with remaining needs, including additional reserve margin, served through market purchases. Montana has been a net exporter of electric generation and we have relied upon Montana's excess generation for grid reliability and to physically serve customers. A significant number of base-load generation facilities, which may also serve to meet peak requirements, in the state and region have been retired or are scheduled to be retired in the next five to ten years. This includes Colstrip Units 1 and 2, representing 614 MWs of generation on a capacity basis, which ceased operations in January 2020. A decrease in the state and region’s electric capacity, whether for operational reasons or litigation outcomes, may impair the reliability of the grid, particularly during peak demand periods. There can be no assurance that there will be available counterparties to contract with to serve our customers' needs, or that these counterparties will fulfill their obligations to us. There is also no assurance that the transmission capacity required to import market purchases will be available on transmission systems owned by us or by third parties. In addition, the suppliers under these agreements may experience financial or operational problems that inhibit their ability to fulfill their obligations to us. These conditions could result in an inability to physically deliver electricity to our customers.

Losing electric service during extreme conditions carries significant consequences, as without our services our customers may be subjected to dire circumstances.

Commodity pricing is an inherent risk component of our business operations and our financial results. Even though rate regulation is premised on full recovery of prudently incurred costs and a reasonable rate of return on invested capital, there can be no assurance that our costs are recoverable as discussed above. The prevailing market prices for electricity may fluctuate substantially over relatively short periods of time, potentially adversely impacting our results of operations, financial condition and cash flows due to our need for market purchases and the sharing component of the Montana PCCAM. During 2021 and during the first nine months of 2022, market prices for electricity and natural gas in peak periods were increasingly volatile, resulting in a significant under-collection of these costs impacting our results of operations and cash flows.

In addition, our natural gas system serves both retail customers and the needs of natural gas fired electric generation. The natural gas system has capacity constraints that expose us to risks to be able to deliver natural gas during periods of peak demand.

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

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

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

Decreasing use per customer (driven, for example, by appliance and lighting efficiency) and the availability of cost-effective distributed generation, put downward pressure on load growth. Our most recent resource plans include an expected annual load growth assumption of 0.4 percent in Montana and 0.7 percent in South Dakota, which reflects low customer and usage increases, offset in part by these load reduction measures. Reductions in usage, attributable to various factors could materially affect our results of operations, financial position, and cash flows through, among other things, reduced operating revenues, increased operating and maintenance expenses, and increased capital expenditures, as well as potential asset impairment charges or accelerated depreciation and decommissioning expenses over shortened remaining asset useful lives.

Demand for our Montana transmission capacity fluctuates with regional demand, fuel prices and weather related conditions. The levels of wholesale sales depend on the wholesale market price, market participants, transmission availability, the availability of generation, and the ongoing development of the Western Energy Imbalance Market, 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.

The COVID-19 pandemic, or similar widespread public health concern, could have a material negative impact on our business, financial condition and results of operations.

The actual or perceived effects of a disease outbreak, epidemic, pandemic or similar widespread public health concern, such as COVID-19, will likely negatively affect our business, financial condition and results of operations. The COVID-19 pandemic has had widespread impacts on people, economies, businesses and financial markets.

Our financial results in 2020 were impacted by lower sales volumes, an increase in reserves for uncollectible accounts and an increase in interest expense, partly offset by lowering operating, general and administrative expense as a result of the COVID-19 pandemic. The long-term impact of the COVID-19 pandemic is highly uncertain and subject to change, and also depends on factors beyond our knowledge or control, including the ultimate duration and severity of this outbreak, third-party actions taken to contain its spread and mitigate its public health effects, and possible federal or state legislative actions related to utility operations, including disconnect moratoriums, or additional economic stimulus packages.

While the COVID-19 pandemic has not caused material disruptions to our operations, we could experience such disruptions in the future as a result of the pandemic (or a similar widespread public health concern) due to, among other things, quarantines, increased cyber risk due to employees working from home, worker absenteeism as a result of illness or other factors, social distancing measures and other travel, health-related, business or other restrictions. If a significant percentage of our workforce is unable to work, including because of illness, travel restrictions, or government mandates in connection with pandemics or disease outbreaks, our operations may be negatively affected.

National, state and local governments have responded to the COVID-19 pandemic in a variety of ways, including, without limitation, by declaring states of emergency, restricting people from gathering in groups or interacting within a certain physical distance (i.e., social distancing), and in certain cases, ordering businesses to close or limit operations or people to stay at home. While there has been a general easing of restrictions through 2021 and into 2022, there can be no guarantee that this trend will continue. Although we provide critical infrastructure services and are permitted to continue to operate in each of our jurisdictions, there may be restrictions imposed on how we operate, such as disconnect moratoriums.

Executive Order 14042 provides, generally, that federal agencies ensure that covered contracts and contract-like instruments include a clause that the federal contractor and any subcontractor be fully vaccinated against COVID-19 and comply with other COVID-related requirements such as social distancing and masking. The Executive Order did not apply to all government contracts. Since then, multiple courts have enjoined the Executive Order's implementation, although the court decisions are not uniform in their application or the states to which the injunction applies. Additionally, the federal government has indicated that it will not, for the time being, enforce the vaccination mandate. However, our obligation to comply with Executive Order 14042 could change in the future depending on the ultimate resolution of court challenges to that Order and any new contracts.

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

Liquidity and Financial Risks

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

Our business strategy 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.

Acquisitions include a number of risks, including but not limited to, regulatory approval, regulatory conditions, additional costs, the assumption of material liabilities, the diversion of our 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.

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. We continue to maintain our investment grade credit ratings. During a 2022 review process, Fitch Ratings downgraded our rating with a stable outlook. Certain of our credit agreements and other credit arrangements with counterparties require us to provide collateral in the form of letters of credit or cash to support our obligations if we fall below investment grade. Also, a downgrade below investment grade could hinder our ability to raise capital on favorable terms and would increase our borrowing costs. Higher interest rates on borrowings with variable interest rates could also have an adverse effect on our results of operations.

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

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

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

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

In addition, we are subject to price escalation risk with one of the largest contracts included in the electric QF liability due to variable contract terms. In recording the electric QF liability, we estimate an annual escalation rate over the remaining term of the contract (through June 2024). To the extent the annual escalation rate exceeds our estimate, 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—Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.

Exhibit 101.SCH—Inline XBRL Taxonomy Extension Schema Document

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

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

Exhibit 101.LAB—Inline XBRL Taxonomy Label Linkbase Document

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

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

SIGNATURES

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

	NorthWestern Corporation
Date: October 25, 2022	By: /s/ CRYSTAL LAIL
	Crystal Lail
	Vice President and Chief Financial Officer
	Duly Authorized Officer and Principal Financial Officer