UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2021

OR

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

For the transition period from to

Commission File Number: 1-10499

NorthWestern Energy

NORTHWESTERN CORP

(Exact name of registrant as specified in its charter)

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

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

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

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

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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 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, 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. Yes ☐ No ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

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

The aggregate market value of the voting and non-voting common stock held by nonaffiliates of the registrant was $3,104,943,983 computed using the last sales price of $60.22 per share of the registrant's common stock on June 30, 2021, the last business day of the registrant's most recently completed second fiscal quarter.

As of February 4, 2022, 54,082,096 shares of the registrant's common stock, par value $0.01 per share, were outstanding.

Documents Incorporated by Reference
Certain sections of our Proxy Statement for the 2022 Annual Meeting of Shareholders are incorporated by reference into Part III of this Form 10-K

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

On one or more occasions, we may make statements in this Annual Report on Form 10-K 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 Annual Report, relating to management's current expectations of future financial performance, continued growth, changes in economic conditions or capital markets and changes in customer usage patterns and preferences are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934.

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

- adverse determinations by regulators, as well as potential adverse federal, state, or local legislation or regulation, including costs of compliance with existing and future environmental requirements, could have a material effect on our liquidity, results of operations and financial condition;
- the impact of extraordinary external events and natural disasters, such as the COVID-19 pandemic, earthquake, flood, drought, lightning, weather, wind, and fire, 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 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 I, Item 1A of this Annual Report on Form 10-K.

From time to time, oral or written forward-looking statements are also included in our reports on Forms 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 Annual Report on Form 10-K, our reports on Forms 10-Q and 8-K, 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 Annual Report on Form 10-K, 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 Annual Report on Form 10-K 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 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.

GLOSSARY

Accounting Standards Codification (ASC) - The single source of authoritative nongovernmental GAAP, which supersedes all existing accounting standards.

Allowance for Funds Used During Construction (AFUDC) - A regulatory accounting convention that represents the estimated composite interest costs of debt and a return on equity funds used to finance construction. The allowance is capitalized in the property accounts and included in income.

Base-Load - The minimum amount of electric power or natural gas delivered or required over a given period of time at a steady rate. The minimum continuous load or demand in a power system over a given period of time usually is not temperature sensitive.

Base-Load Capacity - The generating equipment normally operated to serve loads on an around-the-clock basis.

Capacity - The amount represents the maximum output of electricity a generator can produce and is related to peak demand. We must maintain a level of available capacity sufficient to meet peak demand with a sufficient reserve.

COD - Commercial operating date.

Commercial Customers - Consists primarily of main street businesses, shopping malls, grocery stores, gas stations, bars and restaurants, professional offices, hospitals and medical offices, motels, and hotels.

Cushion Gas - The natural gas required in a gas storage reservoir to maintain a pressure sufficient to permit recovery of stored gas.

DGGS - The Dave Gates Generating Station at Mill Creek, a 150 MW natural gas fired facility.

Environmental Protection Agency (EPA) - A Federal agency charged with protecting the environment.

Federal Energy Regulatory Commission (FERC) - The Federal agency that has jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas transmission and related services pricing, oil pipeline rates and gas pipeline certification.

Franchise - A special privilege conferred by a unit of state or local government on an individual or corporation to occupy and use the public ways and streets for benefit to the public at large. Local distribution companies typically have franchises for utility service granted by state or local governments.

GAAP - Accounting principles generally accepted in the United States of America.

Hedging - Entering into transactions to manage various types of risk (e.g. commodity risk).

Industrial Customers - Consists primarily of manufacturing and processing businesses that turn raw materials into products.

Lignite Coal - The lowest rank of coal, often referred to as brown coal, used almost exclusively as fuel for steam-electric power generation. It has high inherent moisture content, sometimes as high as 45 percent. The heat content of lignite ranges from 9 to 17 million Btu per ton on a moist, mineral-matter-free basis.

Midcontinent Independent System Operator (MISO) - MISO is a nonprofit organization created in compliance with FERC as a regional transmission organization, to improve the flow of electricity in the regional marketplace and to enhance electric reliability. Additionally, MISO is responsible for managing the energy markets, managing transmission constraints, managing the day-ahead, real-time and financial transmission rights markets, and managing the ancillary market.

Midwest Reliability Organization (MRO) - MRO is one of eight regional electric reliability councils under NERC.

Montana Public Service Commission (MPSC) - The state agency that regulates public utilities doing business in Montana.

Nameplate Capacity - The intended full-load sustained output of a generating facility. Nameplate capacity is the number registered with authorities for classifying the power output of a power station usually expressed in megawatts (MW).

Nebraska Public Service Commission (NPSC) - The state agency that regulates public utilities doing business in Nebraska.

Net Operating Loss (NOL) - The result when a company's allowable deductions exceed its taxable income within a tax period.

North American Electric Reliability Corporation (NERC) - NERC oversees eight regional reliability entities and encompasses all of the interconnected power systems of the contiguous United States. NERC's major responsibilities include developing standards for power system operation, monitoring and enforcing compliance with those standards, assessing resource adequacy, and providing educational and training resources as part of an accreditation program to ensure power system operators remain qualified and proficient.

Open Access - Non-discriminatory, fully equal access to transportation or transmission services offered by a pipeline or electric utility.

Open Access Transmission Tariff (OATT) -The OATT, which is established by the FERC, defines the terms and conditions of point-to-point and network integration transmission services offered by us, and requires that transmission owners provide open, non-discriminatory access on their transmission system to transmission customers.

Peak Load - A measure of the maximum amount of energy delivered at a point in time.

Qualifying Facility (QF) - As defined under the Public Utility Regulatory Policies Act of 1978 (PURPA), a QF sells power to a regulated utility at a price agreed to by the parties or determined by a public service commission that is intended to be equal to that which the utility would otherwise pay if it were to generate its own power or buy power from another source.

Reserve Margin - The difference between available capacity and peak demand used in system planning to ensure adequate power supply. A positive percentage indicates the electric system has excess capacity while a negative percentage indicates the electric system is unable to meet peak demand without using market resources.

Securities and Exchange Commission (SEC) - The U.S. agency charged with protecting investors, maintaining fair, orderly and efficient markets and facilitating capital formation.

South Dakota Public Utilities Commission (SDPUC) - The state agency that regulates public utilities doing business in South Dakota.

Southwest Power Pool (SPP) - A nonprofit organization created in compliance with FERC as a regional transmission organization to ensure reliable supplies of power, adequate transmission infrastructure, and a competitive wholesale electricity marketplace. SPP also serves as a regional electric reliability entity under NERC.

Tariffs - A collection of the rate schedules and service rules authorized by a federal or state commission. It lists the rates a regulated entity will charge to provide service to its customers as well as the terms and conditions that it will follow in providing service.

Tolling Contract - An arrangement whereby a party moves fuel to a power generator and receives kilowatt hours (kWh) in return for a pre-established fee.

Transmission - The flow of electricity from generating stations and interconnections with other systems over high voltage lines to substations. The electricity then flows from the substations into a distribution network.

Western Area Power Administration (WAPA) - A federal power-marketing administration and electric transmission agency established by Congress.

Western Electricity Coordination Council (WECC) - WECC is one of eight regional electric reliability councils under NERC.

Measurements:

Billion Cubic Feet (Bcf) - A unit used to measure large quantities of gas, approximately equal to 1 trillion Btu.

British Thermal Unit (Btu) - A basic unit used to measure natural gas; the amount of natural gas needed to raise the temperature of one pound of water by one degree Fahrenheit.

Degree-Day - A measure of the coldness / warmness of the weather experienced, based on the extent to which the daily mean temperature falls below or above 65 degrees Fahrenheit.

Dekatherm - A measurement of natural gas; ten therms or one million Btu.

Kilovolt (kV) - A unit of electrical power equal to one thousand volts.

Megawatt (MW) - A unit of electrical power equal to one million watts or one thousand kilowatts.

Megawatt Hour (MWH) - One million watt-hours of electric energy. A unit of electrical energy which equals one megawatt of power used for one hour.

ITEM 1. BUSINESS

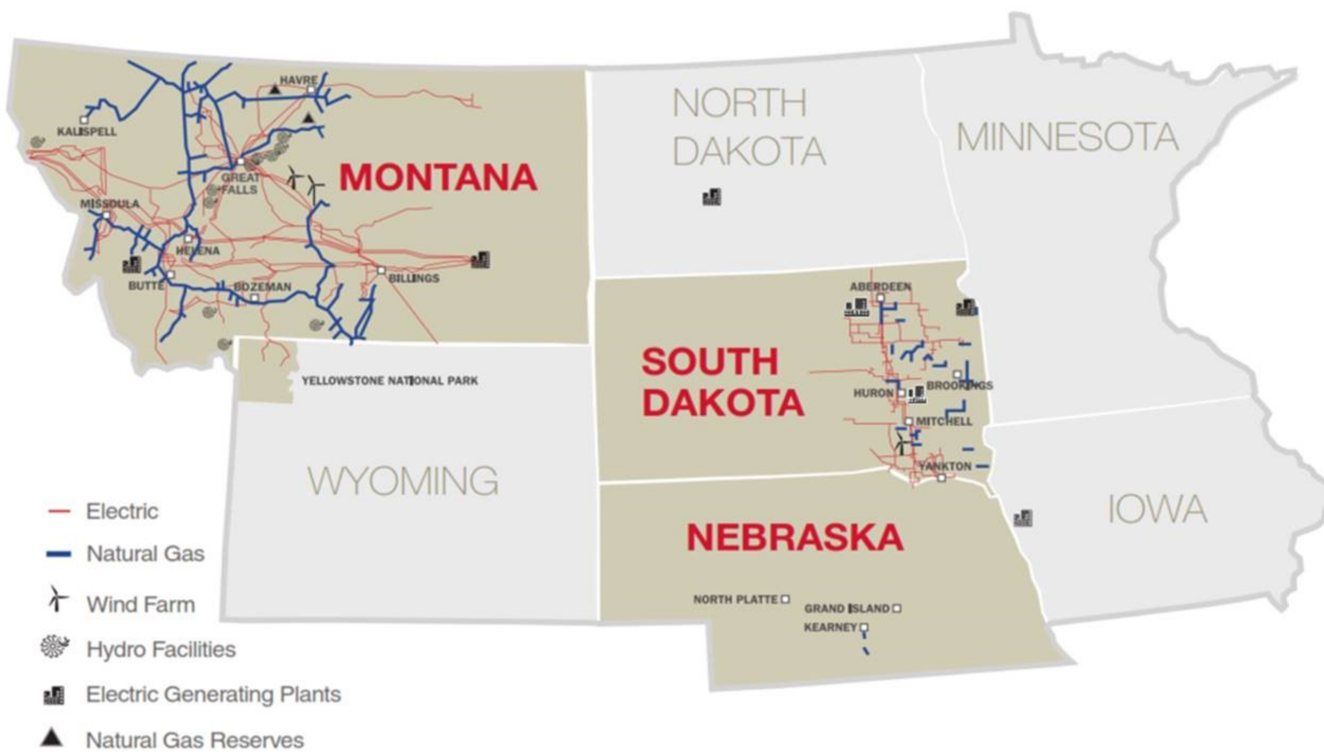
OVERVIEW

NorthWestern Energy - Delivering a Bright Future

NorthWestern Corporation, doing business as NorthWestern Energy, provides essential energy infrastructure and valuable services that enrich lives and empower communities while serving as long-term partners to our customers and communities. 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 provide electricity and / or natural gas to approximately 753,600 customers in Montana, South Dakota, Nebraska, and Yellowstone National Park. We have provided service in South Dakota and Nebraska since 1923 and in Montana since 2002.

We manage our businesses by the nature of services provided, and operate principally in three business segments: electric utility operations; natural gas utility operations; and all other, which primarily consists of unallocated corporate costs. Our electric utility operations include the generation, purchase, transmission and distribution of electricity, and our natural gas utility operations include the production, purchase, transmission, storage, and distribution of natural gas. Our customer base consists of a mix of residential, commercial, and diversified industrial customers.

Our electric and natural gas utility operations are not dependent on a single customer, or even a few customers, and the loss of any one or even a few of our largest customers is not reasonably likely to have a material adverse effect on our financial condition. Our utility operations are seasonal and weather patterns can have a material impact on operating performance. Consumption of electricity is often greater in the summer and winter months for cooling and heating, respectively. Because natural gas is used primarily for residential and commercial heating, the demand for this product depends heavily upon weather patterns throughout our service territory, and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season.



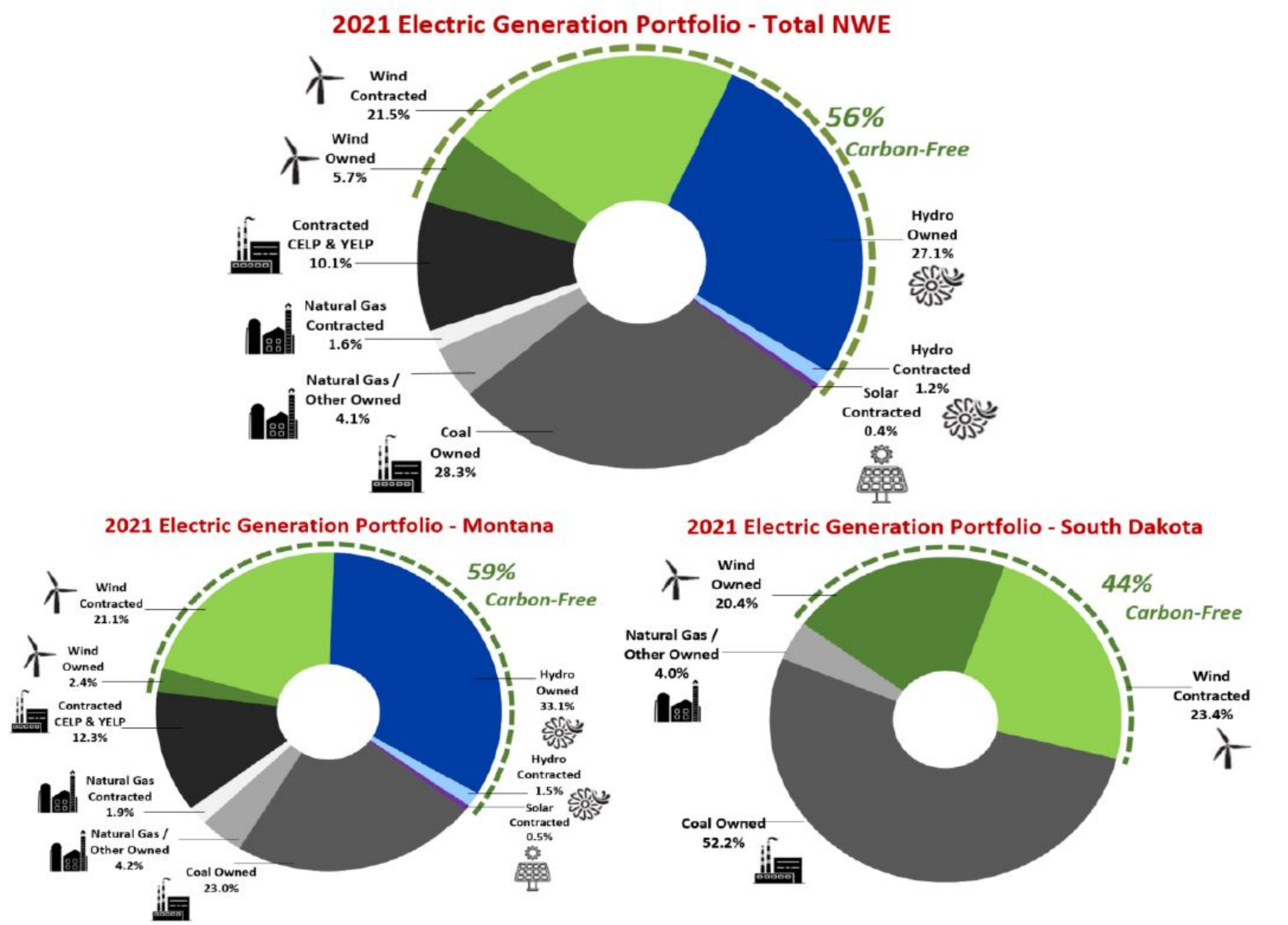
Environmental, Social and Governance

We are focused on meeting current energy infrastructure and service needs at a reasonable and fair cost for today's customers while ensuring the ability to meet the needs of tomorrow's customers. "Sustainability" requires meeting economic, societal, and environmental objectives. As a provider of essential infrastructure and service, a sustainable enterprise is vital to our customers and communities, as well as to our investors and employees. For a full description of our environmental, social, governance and sustainability activities, please see our reports at https://www.northwesternenergy.com.

We strive to balance legal requirements to provide cost-effective, reliable and stably priced energy with being good stewards of natural resources and a diligent focus on sustainability. As discussed below, we currently have a commitment to reduce the carbon intensity of our electric energy portfolio for Montana by 90 percent by 2045. Further, as part of our continued efforts in environmental stewardship, we are developing a comprehensive company-wide carbon reduction plan we intend to announce during 2022.

We currently own a mix of clean and carbon-free energy resources balanced with traditional energy sources that are necessary for us to deliver affordable and reliable electricity to our customers 24/7. In 2021, approximately 56 percent of our retail needs originated from carbon-free resources, compared to approximately 40 percent for the total U.S. electric power industry. We do not receive all the related Renewable Energy Credits (RECs) from our contracted electric supply resources. The owner of the RECs claims the renewable attributes of the energy. Our resource mix does not represent the actual energy delivered to our customers. Market purchases and sales fill the gap between resources and customer demand.

Output from our carbon-free resources decreased from 65% of total supply needs in 2020 to 56% in 2021 due primarily to lower hydro generation caused by drought conditions in Montana. The reduced hydro output was supplemented by market purchases and increased output from dispatchable generation facilities.



Based on MWh's supplied from owned & long-term contracted resources

Contracted energy from Colstrip Energy Limited Partners (CELP), Yellowstone Energy Limited Partners (YELP) as well as a majority of the contracted wind, hydro and solar are federally mandated Qualifying Facilities, as defined under the Public Utility Regulatory Policies Act of 1978 (PURPA).

Montana - Commitment to Reduction in Carbon Intensity

Nearly 60% of the electric energy we supply in Montana comes from carbon-free sources, including hydro, wind and solar. In December 2019, we announced a commitment to reduce the carbon intensity of our electric energy portfolio for Montana by 90 percent by 2045 as compared with our 2010 carbon intensity as a baseline. Since 2010, we have already reduced the carbon intensity of our Montana generation portfolio by more than 50 percent.

MONTANA ELECTRIC OPERATIONS

Our regulated electric utility business in Montana includes generation, transmission and distribution. Our service territory covers approximately 107,600 square miles, representing approximately 73 percent of Montana's land area. During 2021, we delivered electricity to approximately 391,400 customers in 208 communities and their surrounding rural areas, 11 rural electric cooperatives and, in Wyoming, to the Yellowstone National Park. In 2021, by category, residential, commercial, industrial, and other sales accounted for approximately 44%, 47%, 5%, and 4%, respectively, of our Montana retail electric utility revenue.

Transmission and Distribution

Our electric system is composed of high voltage transmission lines and low voltage distribution lines as follows:

Electric Transmission Lines	
Miles of 500 kV	497
Miles of 230 kV	987
Miles of 161 kV	1,184
Miles of 115 kV and lower voltage	4,151
Total Miles of Electric Transmission Lines	**6,819**
Electric Distribution Lines	
Miles of overhead line	13,061
Miles of underground line	5,116
Total Miles of Electric Distribution Lines	**18,177**
Total Transmission and Distribution Substations	**400**

In addition to delivering energy to distribution systems to serve customers, we also transmit electricity for nonregulated entities owning generation, and utilities, cooperatives, and power marketers serving the Montana electricity market. Our total control area peak demand was approximately 1,909 MWs on January 27, 2021. Our control area average demand for 2021 was approximately 1,321 MWs per hour, with total energy delivered of more than 11.57 million MWHs.

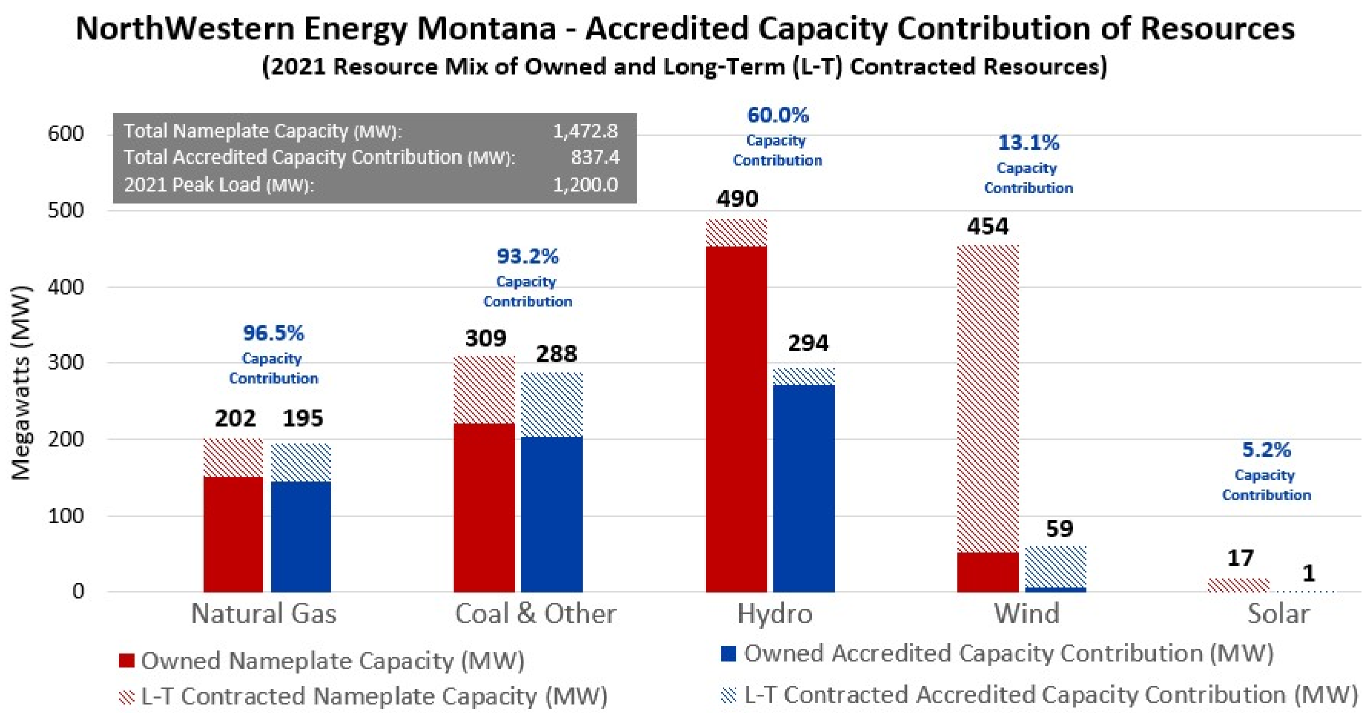
Our transmission system is directly interconnected with Avista Corporation; Idaho Power Company; PacifiCorp; the Bonneville Power Administration; WAPA; and Montana Alberta Tie Ltd. Such interconnections, coupled with transmission line capacity made available under agreements with some of the above entities, permit the interchange, purchase, and sale of power among all major electric systems in the west interconnecting with the winter-peaking northern and summer-peaking southern regions of the western power system. We provide wholesale transmission service and firm and non-firm transmission services for eligible transmission customers pursuant to our FERC Open Access Transmission Tariff. Our 500 kV transmission system, which is jointly owned, along with our 230 kV and 161 kV facilities, form the key assets of our Montana transmission system. Lower voltage systems provide transmission for local area service needs.

Electric Supply

Our annual retail electric supply load requirements average approximately 750 MWs, with a peak load of approximately 1,200 MWs, and are supplied by owned and contracted resources and market purchases with multiple counterparties.

Owned generation resources supplied approximately 60 percent of our retail load requirements for 2021. We expect that approximately 60 percent of our retail obligations will be met by owned generation resources in 2022. In addition, QFs provide a total of 389 MWs of contracted resources, including 87 MWs from waste petroleum coke and waste coal, 268 MWs from wind, 16 MWs from hydro, and 17 MWs from solar projects. We have several other long and medium-term power purchase agreements including contracts for 135 MWs of wind generation, 52 MWs of natural gas generation, and 21 MWs of seasonal base-load hydro supply. For 2022, including both owned and contracted resources, we have resources to provide over 90 percent of the capacity necessary to meet our forecasted retail load requirements.

The following chart depicts the makeup of our current owned and long-term contracted resources within our Montana Electric generation portfolio. Hydro generation is by far our largest and most important resource, as it is reliable, dramatically lowers the portfolio's carbon intensity, and reduces economic risks associated with future carbon costs.

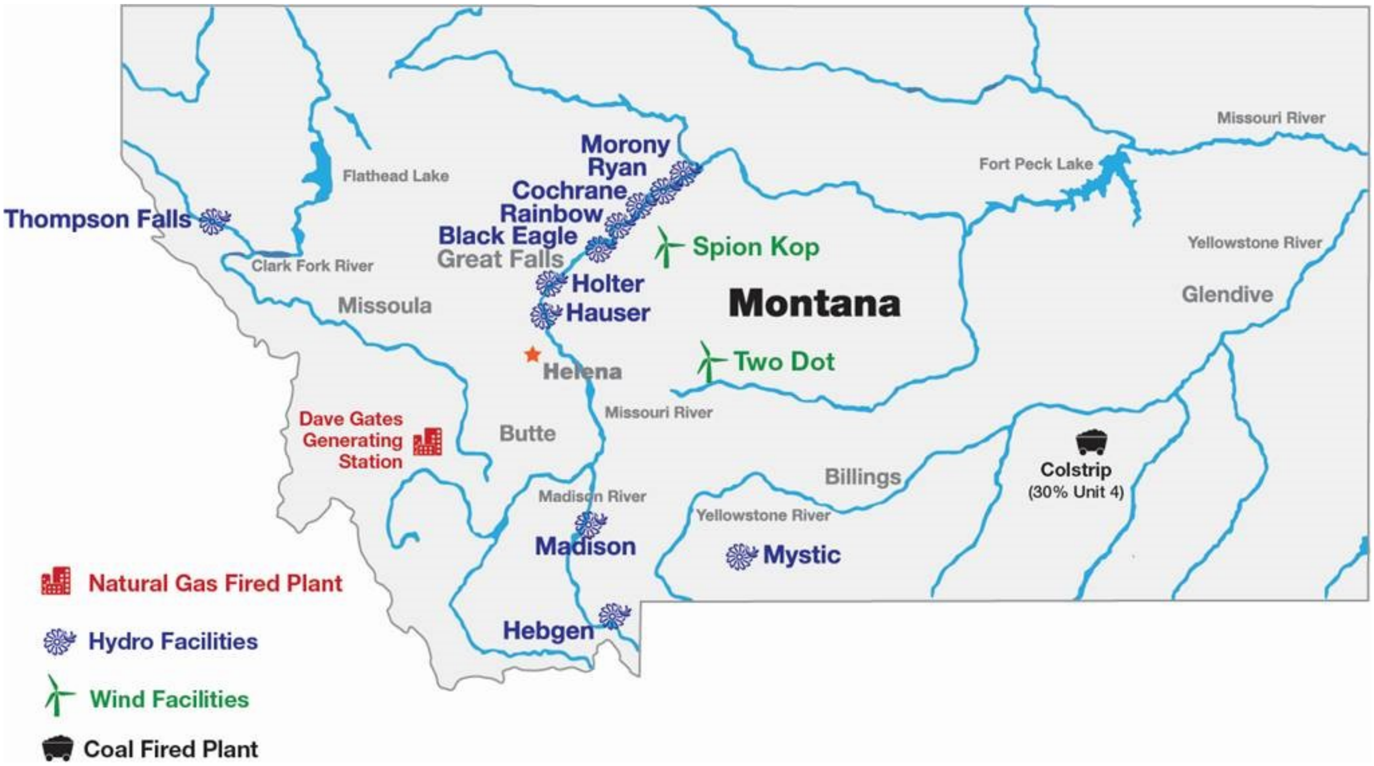


Accredited Capacity Contribution is the ability of each resource fuel-type to contribute to meet demand during peak energy usage by customers.

Accredited Capacity Contribution or Peak Load Contribution is based on Effective Load Carrying Capability (ELCC) E3 Study on Peak Load Measurement for NorthWestern Energy's resources that are on-line or in service as of 12/31/2021 and the ELCC is based on 2021 values.

Coal & Other: 222MW Colstrip (30% ownership in jointly owned coal plant) and 87 MW of Federally mandated Qualifying Facilities (52MW Petroleum-coke contract with Yellowstone Energy Limited Partnership and 35MW waste coal contract with Colstrip Energy Limited Partnership).

Owned Generation Facilities



Details of these generating facilities are described in the following tables.

Hydro Facilities	COD	River Source	FERC License Expiration	Owned MW(1)
Black Eagle	1927	Missouri	2040	21
Cochrane	1958	Missouri	2040	62
Hauser	1911	Missouri	2040	19
Holter	1918	Missouri	2040	53
Madison	1906	Madison	2040	8
Morony	1930	Missouri	2040	49
Mystic	1925	West Rosebud Creek	2050	12
Rainbow	1910/2013	Missouri	2040	64
Ryan	1915	Missouri	2040	71
Thompson Falls	1915/1995	Clark Fork	2025	94
Total				**453**

(1) The Hebgen facility (0 MW net capacity) is excluded from the figures above. These are run-of-river dams except for Mystic, which is storage generation.

Other Facilities	Fuel Source	Ownership Interest	Owned MW
Colstrip Unit 4, located near Colstrip in southeastern Montana	Sub-bituminous coal	30%	222
DGGS, located near Anaconda, Montana	Natural Gas & Liquid Fuel	100%	150
Spion Kop Wind, located in Judith Basin County in Montana	Wind	100%	40
Two Dot Wind, located in Wheatland County in Montana	Wind	100%	11

Colstrip Unit 4 provides base-load supply and is operated by Talen Montana, LLC (Talen). Talen has a 30 percent ownership interest in Colstrip Unit 3. We have a reciprocal sharing agreement with Talen regarding the operation of Colstrip Units 3 and 4, in which each party receives 15 percent of the respective combined output and is responsible for 15 percent of the respective operating and construction costs, regardless of whether a particular cost is specified to Colstrip Unit 3 or 4. However, each party is responsible for its own fuel-related costs. Colstrip Unit 4 is supplied with fuel from adjacent coal reserves under a coal supply agreement in effect through 2025. See *Item 1A Risk Factors* "Regulatory, Legislative and Legal Risks" for further discussion regarding the service life of generation facilities.

Resource Planning

Resource planning is an important function necessary to meet our customers' future energy needs and is used to guide resource acquisition activities. We filed our latest resource plan with the MPSC in August 2019 and supplemented that plan in December 2020. Both filings projected generation capacity deficits and negative reserve margins. Since that time, we have been working to address the deficit with a combination of owned resources and long-term capacity contracts as well as short-and-intermediate term capacity contracts.

We issued an all-source competitive solicitation request in January 2020 for up to 280 MWs of peaking and flexible capacity to be available for commercial operation in early 2023. In addition to our responsibility to meet peak demand, national NERC reliability standards increased the need for us to have greater dispatchable generation capacity available and be capable of increasing or decreasing output to address the irregular nature of intermittent generation such as wind or solar. Our generation portfolio is a balanced mix of energy and capacity resources having different operating characteristics and fuel sources designed to provide energy at the lowest possible cost to meet our obligation to serve retail customers while maintaining reliability.

Western Energy Imbalance Market

We entered the Western Energy Imbalance Market (Western EIM), operated by the California Independent System Operator (California ISO), on June 16, 2021. We studied the value and costs of the Western EIM for several years prior to the decision to participate in the Western EIM. Utilities in the western United States outside the California ISO have traditionally relied upon a combination of automated and manual dispatch within the hour to balance generation and load to maintain reliable supply. Under this traditional framework, these utilities have limited capability to transact within the hour outside their balancing area. In contrast, energy imbalance markets use automated intra-hour economic dispatch of generation from committed resources to serve loads. The Western EIM is intended to reduce power supply costs to serve customers through more efficient dispatch of a larger and more diverse pool of resources, to integrate intermittent power more effectively, and to enhance reliability. We have Western EIM transactions enabled with PacifiCorp and Idaho Power Company. We expect Avista and the Bonneville Power Administration to join the Western EIM by the second quarter of 2022, allowing us to enable EIM transactions with those parties, as well. Participation in the Western EIM is voluntary and available to all balancing authorities in the western United States. The Western EIM currently includes over 14 participating authorities.

SOUTH DAKOTA ELECTRIC OPERATIONS

Our South Dakota electric utility business operates as a vertically integrated generation, transmission and distribution utility. We have the exclusive right to serve an area in South Dakota comprised of 25 counties. We provide retail electricity to more than 64,200 customers in 110 communities in South Dakota. In 2021, by category, residential, commercial and other sales accounted for approximately 38%, 60%, and 2%, respectively, of our South Dakota retail electric utility revenue.

Transmission and Distribution

Our electric system includes high voltage transmission and low voltage distribution lines as follows:

Electric Transmission Lines	
Miles of 345 kV	25
Miles of 230 kV	18
Miles of 115 kV and lower voltages	1,265
Total Miles of Electric Transmission Lines	**1,308**
Electric Distribution Lines	
Miles of overhead line	1,615
Miles of underground line	705
Total Miles of Electric Distribution Lines	**2,320**
Total Transmission and Distribution Substations	**120**

Our South Dakota system is interconnected with the transmission facilities of Otter Tail Power Company; Montana-Dakota Utilities Co.; Xcel Energy Inc.; and WAPA. We have emergency interconnections with the transmission facilities of East River Electric Cooperative, Inc. and West Central Electric Cooperative.

We are a transmission-owning member in the SPP. Each year, we review all new or modified transmission assets and transfer functional control of assets that qualify under the SPP Tariff to the SPP. This annual update goes into effect on April 1st each year. To date, we have transferred control of 333 line miles of 115 kV facilities and over 158 line miles of 69 kV facilities. The Coyote, Big Stone, and Neal power plants, which we jointly own, are connected directly to the MISO system. Our ownership rights in the transmission lines from these plants to our distribution system allow us to move the power to our customers. Along with operating the transmission system, SPP also coordinates regional transmission planning for all of its members.

Electric Supply

Our annual retail electric supply load requirements average approximately 200 MWs, with a peak load of 344 MWs, and are supplied by owned and contracted resources and market purchases. We use market purchases and peaking generation to provide peak supply in excess of our base-load capacity. We are a member of the SPP. As a market participant in SPP, we buy and sell wholesale energy and reserves in both day-ahead and real-time markets through the operation of a single, consolidated SPP balancing authority. We and other SPP members submit into the SPP market both offers to sell our generation and bids to purchase power to serve our load. SPP optimizes next-day and real-time generation dispatch across the region and provides participants with greater access to economic energy. Marketing activities in SPP are handled for us by a third-party provider acting as our agent.

Our electric supply resources include 210 MWs from jointly owned coal plants and an 80 MW natural gas plant. Additional resources include several natural gas peaking units and an 80 MW wind facility. We also purchase the output of four wind projects, three of which are QFs, under power purchase agreements. Actual output for our wind resources varies based upon weather conditions.

Owned Generation Facilities

Details of our generating facilities are described further in the following chart:

Generation Facilities	Fuel Source	Ownership Interest	Owned MW
Big Stone Plant, located near Big Stone City in northeastern South Dakota	Sub-bituminous coal	23.4%	111
Aberdeen Generating Units No. 1 and 2, located near Aberdeen, South Dakota	Natural gas & Liquid Fuel	100.0%	80
Beethoven Wind Project, located near Tripp, South Dakota	Wind	100.0%	80
Neal Electric Generating Unit No. 4, located near Sioux City, Iowa	Sub-bituminous coal	8.7%	56
Coyote I Electric Generating Station, located near Beulah, North Dakota	Lignite coal	10.0%	43
Miscellaneous combustion turbine units and small diesel units (used only during peak periods)	Combination of fuel oil and natural gas	100.0%	25
Total			395

The Big Stone, Coyote and Neal plants are owned jointly with unaffiliated parties. Each of the jointly owned plants is subject to a joint management structure, and we are not the operator of any of these plants. Based on our ownership interest, we are entitled to a proportionate share of the capacity of our jointly owned plants and are responsible for a proportionate share of the operating costs.

The fuel for our jointly owned base-load generating plants is provided through supply contracts of various lengths with several coal companies. Coyote is a mine-mouth generating facility. Neal #4 and Big Stone receive their fuel supply via rail. The average delivered cost by type of fuel burned varies between generation facilities due to differences in transportation costs and owner purchasing power for coal supply. Changes in our fuel costs are passed on to customers through the operation of the fuel adjustment clause in our South Dakota tariffs.

Resource Planning

We have a resource plan that includes estimates of customer usage and programs to provide for the economic, reliable and timely supply of energy. We continue to update our load forecast to identify the future electric energy needs of our customers, and we evaluate additional generating capacity requirements on an ongoing basis.

We submitted a plan to the SDPUC in 2018 to provide for the modernization of our generating fleet, which is focused on improving reliability and flexibility. Based on the results of associated competitive solicitation processes, we are currently constructing the 58 MW Bob Glanzer Plant. This plant, which is expected to be in service in the second quarter of 2022, includes flexible reciprocating internal combustion engines at a brownfield site near Huron, South Dakota, with an estimated construction cost of approximately $80 million. We expect to file an updated resource plan in late 2022.

NATURAL GAS OPERATIONS

Montana

Our regulated natural gas utility business in Montana includes production, storage, transmission and distribution. During 2021, we distributed natural gas to approximately 206,600 customers in 118 Montana communities over a system that consists of approximately 4,900 miles of underground distribution pipelines. We also serve several smaller distribution companies that provide service to approximately 37,000 customers. We transmit natural gas in Montana from production receipt points and storage facilities to distribution points and other nonaffiliated transmission systems. We transported natural gas volumes of approximately 44 Bcf during the year ended December 31, 2021.

Miles of Natural Gas Transmission	**2,166**
Miles of Natural Gas Distribution	**4,945**
City Gate Stations	**138**

We have connections in Montana with four major, unaffiliated transmission systems: Williston Basin Interstate Pipeline, NOVA Gas Transmission Ltd., Colorado Interstate Gas, and Spur Energy. Twelve compressor sites provide more than 38,000 horsepower on the transmission line and an additional 15,000 horsepower at our storage fields, capable of moving more than 350,000 dekatherms per day. In addition, we own and operate two transmission pipelines through our subsidiaries, Canadian-Montana Pipe Line Corporation and Havre Pipeline Company, LLC.

Natural gas is used primarily for residential and commercial heating, and as fuel for two electric generating facilities. The demand for natural gas largely depends upon weather conditions. Our Montana retail natural gas supply requirements for the year ended December 31, 2021, were approximately 20.8 Bcf. Our Montana natural gas supply requirements for electric generation fuel for the year ended December 31, 2021, were approximately 4.2 Bcf. We have contracted with several major producers and marketers with varying contract durations to provide the anticipated supply to meet ongoing requirements. Our natural gas supply requirements are fulfilled through third-party fixed-term purchase contracts, short-term market purchases and owned production. Our portfolio approach to natural gas supply is intended to enable us to maintain a diversified supply of natural gas sufficient to meet our supply requirements. We benefit from direct access to suppliers in significant natural gas producing regions in the United States, primarily the Rocky Mountains (Colorado), Montana, and Alberta, Canada.

Owned Production and Storage - Since 2010, we have acquired gas production and gathering system assets as a part of an overall strategy to provide rate stability and customer value: as we own these assets, which are regulated, our customers are protected from potential price spikes in the market. As of December 31, 2021, these owned reserves totaled approximately 38.8 Bcf and are estimated to provide approximately 3.3 Bcf in 2022, or about 15 percent of our expected annual retail natural gas load in Montana. In addition, we own and operate three working natural gas storage fields in Montana with aggregate working gas capacity of approximately 17.85 Bcf and maximum aggregate daily deliverability of approximately 203,400 dekatherms.

South Dakota and Nebraska

We provide natural gas to approximately 48,600 customers in 62 South Dakota communities and approximately 42,800 customers in three Nebraska communities. In South Dakota, we also transport natural gas for nine gas-marketing firms and three large end-user accounts. In Nebraska, we transport natural gas for four gas-marketing firms and one large end-user account. We delivered approximately 30.0 Bcf of third-party transportation volume on our South Dakota distribution system and approximately 3.7 Bcf of third-party transportation volume on our Nebraska distribution system during 2021.

Miles of Natural Gas Transmission	**55**
Miles of Natural Gas Distribution	**2,517**

Our South Dakota natural gas supply requirements for the year ended December 31, 2021, were approximately 5.6 Bcf. We contract with a third party under an asset management agreement to manage transportation and storage of supply to minimize cost and price volatility to our customers. In Nebraska, our natural gas supply requirements for the year ended December 31, 2021, were approximately 4.2 Bcf. We contract with a third party under an asset management agreement that includes pipeline capacity, supply, and asset optimization activities. To supplement firm gas supplies in South Dakota and Nebraska, we contract for firm natural gas storage services to meet the heating season and peak day requirements of our customers.

Municipal Natural Gas Franchise Agreements - We have municipal franchises to provide natural gas service in the communities we serve. The terms of the franchises vary by community. Our Montana franchises typically have a fixed 10-year term and continue for additional 10-year terms unless and until canceled, with 5 years notice. The maximum term permitted under Nebraska law for these franchises is 25 years while the maximum term permitted under South Dakota law is 20 years. Our policy generally is to seek renewal or extension of a franchise in the last year of its term. We continue to serve those customers while we obtain formal renewals. During the next five years, seven of our Montana franchises could expire by action taken by the city or town, which account for approximately 89,534 or 21.7 percent of our Montana natural gas customers. Five of our South Dakota franchises and one franchise in Nebraska, which account for approximately 25,900 or 28 percent of our South Dakota and Nebraska natural gas customers, are scheduled to reach the end of their fixed term during the next five years. We do not anticipate termination of any of these franchises.

GOVERNMENT REGULATION

NorthWestern's provision of utility service is regulated by the MPSC, the SDPUC, the NPSC, and the FERC. NorthWestern is also regulated by many other state and federal agencies. For example, because NorthWestern's operations impact land, waterways and the air, NorthWestern is subject to a wide range of regulations administered by the federal Environmental Protection Agency, the U.S. Fish & Wildlife Service, and parallel state agencies regulating environmental and natural resources in Montana, South Dakota and Nebraska. Another example relates to NorthWestern's provision of natural gas service. The U.S. Department of Transportation through the Pipeline and Hazardous Materials Safety Administration, along with its state partners, regulates natural gas pipeline and natural gas storage field safety. As a publicly-traded company, we are subject to the SEC's requirements regarding financial reporting, disclosures, and laws and regulations protecting investors. We are subject to the Occupational Safety and Health Administration (OSHA), which regulates workplace safety. We are also subject to local zoning laws and regulations.

As detailed below, the rates we charge our utility customers are set through approval by the regulatory commission with jurisdiction in each of our respective service territories. Base rates are the rates that are intended to allow us the opportunity to collect from our customers total revenues (revenue requirements) equal to our cost of providing delivery and rate-based supply services, plus a reasonable rate of return on invested capital. We have both electric and natural gas base rates and cost tracking clauses. We may ask the respective regulatory commission to increase base rates from time to time. Rate increases are normally granted based on historical data and those increases may not always keep pace with increasing costs. For more information on current regulatory matters, see Note 3 - Regulatory Matters, to the Consolidated Financial Statements.

The following is a summary of our rate base (amounts we earn a return on) and authorized rates of return in each jurisdiction, estimated as of December 31, 2021:

Jurisdiction and Service	Implementation Date	Authorized Rate Base (millions)	Estimated Rate Base (millions)	Authorized Overall Rate of Return	Authorized Return on Equity	Authorized Equity Level
Montana electric delivery and production(1)	April 2019	$2,030.1	$2,596.5	6.92%	9.65%	49.38%
Montana - Colstrip Unit 4	April 2019	304.0	270.1	8.25%	10.00%	50.00%
Montana natural gas delivery and production(2)	September 2017	430.2	536.7	6.96%	9.55%	46.79%
Total Montana		$2,764.3	$3,403.3			
South Dakota electric(3)	December 2015	$557.3	$635.8	7.24%	n/a	n/a
South Dakota natural gas(3)	December 2011	65.9	80.8	7.80%	n/a	n/a
Total South Dakota		$623.2	$716.6			
Nebraska natural gas(3)	December 2007	$24.3	$39.5	8.49%	10.40%	n/a
		$3,411.8	$4,159.4			

(1) The revenue requirement associated with the FERC regulated portion of Montana electric transmission and ancillary services are included as revenue credits to our MPSC jurisdictional customers. Therefore, we do not separately reflect FERC authorized rate base or authorized returns.

(2) The Montana gas revenue requirement includes a step down which approximates annual depletion of our natural gas production assets included in rate base.

(3) For those items marked as "n/a," the respective settlement and/or order was not specific as to these terms.

MPSC Regulation

Our Montana operations are subject to the jurisdiction of the MPSC with respect to rates, terms and conditions of service, accounting records, electric service territorial issues and other aspects of our operations, including when we issue, assume, or guarantee securities in Montana, or when we create liens on our regulated Montana properties. We have an obligation to provide service to our customers with an opportunity to earn a regulated rate of return.

Electric Supply Tracking Mechanism - The Power Cost and Credit Adjustment Mechanism (PCCAM) tracks, for recovery through utility rates, the cost of power purchased and fuel used to generate electricity. The PCCAM incorporates sharing of a portion of the business risk or benefit associated with the energy supply costs with 90 percent of the variance above or below the established base revenues and actual costs collected from or refunded to customers. Customer prices may be adjusted annually to absorb the difference for the annual tracking period. Annual filings are based on a July through June 12-month tracking period, and are subject to review by the MPSC to determine if electric supply procurement activities were prudent. If the MPSC subsequently determines that a procurement activity was imprudent, recovery of such costs may be disallowed.

Natural Gas Supply Tracker - Rates for our Montana natural gas supply are set by the MPSC. Certain supply rates are adjusted on a monthly basis for volumes and costs during each July to June 12-month tracking period. Annually, supply rates are adjusted to include any differences between the previous tracking year's revenues and expenses for recovery during the subsequent tracking year. We submit annual natural gas tracker filings for the actual 12-month period ended June 30 and for the projected supply costs for the next 12-month period. The MPSC reviews such filings and makes its cost recovery determination based on whether or not our natural gas energy supply procurement activities were prudent. If the MPSC subsequently determines that a procurement activity was imprudent, recovery of such costs may be disallowed.

***Montana Property Tax Tracker* -** We file an annual property tax tracker (including other state/local taxes and fees) with the MPSC for an automatic rate adjustment, which reflects the incremental property taxes since our last base rate filing adjusted for the associated income tax benefit.

***Fixed Cost Recovery Mechanism Pilot* -** In our 2018 Montana electric rate settlement, the MPSC approved a Fixed Cost Recovery Mechanism Pilot (FCRM), intended to decouple our recovery of fixed, test-year based transmission, distribution, and production costs from sales of energy. At our request, the MPSC delayed implementation of the pilot to July 1, 2022. The FCRM is expected to function over a four-year pilot period, applying primarily to residential customers.

SDPUC Regulation

Our South Dakota operations are subject to SDPUC jurisdiction with respect to rates, terms and conditions of service, accounting records, electric service territorial issues and other aspects of our electric and natural gas operations. Our retail electric rates, approved by the SDPUC, provide several options for residential, commercial and industrial customers, including dual-fuel, interruptible, special all-electric heating, and other special rates. Our retail natural gas tariffs include gas transportation rates for transportation through our distribution systems by customers and natural gas marketers from the interstate pipelines at which our systems take delivery to the end-user. Such transporting customers nominate the amount of natural gas to be delivered daily. On a daily basis, we monitor usage for these customers and balance it against their respective supply agreements.

An electric adjustment clause provides for quarterly adjustment based on differences in the delivered cost of energy, delivered cost of fuel, ad valorem taxes paid and commission-approved fuel incentives. The adjustment goes into effect upon filing, and is deemed approved within 10 days after the information filing unless the SDPUC staff requests changes during that period. A purchased gas adjustment provision in our natural gas rate schedules permits the monthly adjustment of charges to customers to reflect increases or decreases in purchased gas, gas transportation and ad valorem taxes.

NPSC Regulation

Our Nebraska natural gas rates and terms and conditions of service for residential and smaller commercial customers are regulated by the NPSC. High volume customers are not subject to such regulation, but can file complaints if they allege discriminatory treatment. Under the Nebraska State Natural Gas Regulation Act, a regulated natural gas utility may propose a change in rates to its regulated customers, if it files an application for a rate increase with the NPSC and with the communities in which it serves customers. The utility may negotiate with those communities for a settlement with regard to the proposed rate change if the affected communities representing more than 50 percent of the affected ratepayers agree to direct negotiations, or it may proceed to have the NPSC review the filing and make a determination. Our tariffs have been approved by the NPSC, and the NPSC has adopted certain rules governing the terms and conditions of service of regulated natural gas utilities. Our retail natural gas tariffs provide residential, general service and commercial and industrial options, as well as firm and interruptible transportation service. A purchased gas adjustment clause provides for adjustments based on changes in gas supply and interstate pipeline transportation costs.

FERC Regulation

We are subject to FERC's jurisdiction and regulations with respect to rates for electric transmission service and electricity sold at wholesale, hydro licensing and operations, the issuance of certain securities, incurrence of certain long-term debt, and compliance with mandatory reliability standards, among other things. Under FERC's open access transmission policy promulgated in Order No. 888, as owners of transmission facilities, we are required to provide open access to our transmission facilities under filed tariffs at cost-based rates. In addition, we are required to comply with FERC's Standards of Conduct for Transmission Providers.

Our Montana wholesale transmission customers, such as cooperatives, industrial customers, and other customers that have third-party commodity supply providers, are served under our OATT, which is on file with FERC. The OATT defines the terms, conditions, and rates of our Montana transmission service, including ancillary services. Our South Dakota transmission operations are in the SPP, and transmission service is provided under the SPP OATT.

Our natural gas transportation pipelines are generally not subject to FERC's jurisdiction, although we are subject to state regulation. We conduct limited interstate transportation in Montana and South Dakota that is subject to FERC jurisdiction, and FERC has allowed the MPSC and SDPUC to set the rates for this interstate service. We have capacity agreements in South Dakota and Nebraska with interstate pipelines that are also subject to FERC jurisdiction.

Our hydroelectric generating facilities are licensed by the FERC and operated under the terms of those licenses and FERC regulations. In connection with the relicensing of these generating facilities, applicable law permits the FERC to issue a new license to the existing licensee, to a new licensee, or alternatively allows the U.S. government to take over the facility. If the existing licensee is not relicensed, it is compensated for its net investment in the facility, not to exceed the fair value of the property taken, plus reasonable severance damages to other property affected by the lack of relicensing.

***Reliability Standards* -** We must comply with the standards and requirements that apply to the NERC functions for which we have registered in both the MRO for our South Dakota operations and the WECC for our Montana operations. WECC and the MRO have responsibility for monitoring and enforcing compliance with the FERC-approved mandatory reliability standards within their respective regions. We expect that the reliability standards will continue to evolve and change as a result of modifications, guidance, and clarification following industry implementation and ongoing audits and enforcement.

COMPETITION

We are subject to public policies that promote competition and development of energy markets. Our industrial and large commercial customers have the ability to choose their electric supplier and may generate their own electricity. In addition, customers may have the option of substituting other fuels or relocating their facilities to a lower cost region. Customers have the opportunity to supply their own power with distributed generation including solar generation, and in Montana, can currently avoid paying for most of the fixed production, transmission and distribution costs incurred to serve them. These incentives and federal tax subsidies make distributed generating resources viable potential competitors to our electric service business.

In addition, the FERC has continued to promote competitive wholesale markets through open access transmission and other means. Our wholesale customers can purchase their output from generation resources of competing suppliers or non-contracted quantities and use the transmission systems to serve their load. There is also competition for available transmission capacity to meet our electric supply needs to serve customers.

ENVIRONMENTAL

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, and protection of natural resources and wildlife. We monitor federal, state, and local environmental initiatives to determine potential impacts on our financial results. As new laws or regulations are issued, we assess their applicability and implement the necessary modifications to our facilities or their operation to maintain ongoing compliance.

To this end, the Biden Administration set ambitious goals to address climate change, including the goal of a carbon free power sector by 2035 and net zero carbon emissions by 2050. Executive Orders issued by the Biden Administration included initiatives and directives intended to reduce greenhouse gas (GHG) emissions, address climate change and decarbonize the energy sector. These Executive Orders established climate considerations as key components of United States foreign policy and national security, established a White House Office of Domestic Climate policy as well as a National Climate Task Force, called for agency heads to identify any fossil fuel subsidies provided by their agencies and to take steps to ensure that federal funding is not directly subsidizing fossil fuels, and directed agencies to immediately review all regulations proposed or finalized by the Trump Administration that conflict with the Biden Administration's objectives and to take action to rescind or revise those rules. Months later, President Biden officially rejoined the Paris Accord. More recently, President Biden's proposed Build Back Better legislation contains significant climate initiatives.

Implementation of these initiatives and directives has the potential to limit or curtail our operations, including the burning of fossil fuels at our coal-fired power plants. While we strive to comply with all environmental regulations applicable to our operations, it is not possible to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to energy and environmental laws and regulations, or new administrative or judicial interpretations or enforcement decisions regarding them.

Estimated capital expenditures for environmental control facilities in 2022 and 2023 are not expected to be material. For more information on environmental regulations and contingencies and related capital expenditures, see Note 18 - Commitments and Contingencies, to the Consolidated Financial Statements.

CORPORATE INFORMATION AND WEBSITE

We were incorporated in Delaware in November 1923. Our Internet address is https://www.northwesternenergy.com. Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports, along with our annual report to shareholders and other information related to us, are available, free of charge, on our Internet website as soon as reasonably practicable after we electronically file those documents with, or otherwise furnish them to, the SEC. This information is available in print to any shareholder who requests it. Requests should be directed to: Investor Relations, NorthWestern Corporation, 3010 W. 69th Street, Sioux Falls, South Dakota 57108 and our telephone number is (605) 978-2900. References to our website in this report are provided as a convenience and do not constitute, and should not be viewed as, an incorporation by reference of the information contained on, or available through, the website. Therefore, such information should not be considered part of this report.

HUMAN CAPITAL RESOURCES

Our ability to achieve the objectives of our business strategy and serve our customers within our service territory depends on employing skilled individuals at all levels of our organization. We aspire to be an employer of choice by offering competitive salaries and benefits, providing a safe working environment, valuing diversity, fostering inclusion and encouraging a healthful work–life balance. Our success comes when employees feel empowered to take initiative, voice their opinions, and build on their experiences within our company and our communities.

As of December 31, 2021, we had 1,483 employees. Of these, 1,187 employees were in Montana and 296 were in South Dakota or Nebraska. Of our Montana employees, 440, or 37 percent, were covered by seven collective bargaining agreements involving five unions. Due to the continuing impact of the COVID-19 pandemic, we negotiated a one-year contract extension with a wage proposal for six Montana contracts that were expiring in 2021. All seven of the Montana contracts expire in 2022 and we expect them to be renegotiated. Of our South Dakota and Nebraska employees, 165, or 56 percent, are covered by a collective bargaining agreement renegotiated in 2021 that expires in 2025. We consider our relations with employees to be good.

Talent Management

Attraction and retention of skilled employees is key to our ongoing success. We invest resources in maintaining a culture that supports the ongoing development of our workforce. This includes an integrated learning and performance management system which includes annual performance reviews that link goals and competencies together so that managers are able to provide a holistic view to employees in regards to their performance against goals as well as key competencies as they relate to their role in the organization. This process provides opportunities to develop and enhance skills and knowledge, and enables our employees to grow professionally and perform their duties in a safe and efficient manner. This structured training and development is intended to provide employees a consistent learning experience, and maximizes learning retention and background knowledge. We offer tuition reimbursement to promote continued professional growth for current employees, and a scholarship program for students attending universities, colleges, and technical schools in our service area to assist in developing current and future skills sets needed by our employees. We support annual Pre-apprentice scholarships, recruit and hire suitable candidates from the program, serve as industry advisors on the program board and have donated training assets to support the program.

Compensation

Our overarching compensation philosophy is structured to be consistent with our peers, and to align the long term interests of our employees, executives, shareholders, and customers so the pay appropriately reflects performance in achieving financial and non-financial operating objectives.

We are committed to internal pay equity, and the Human Resources Committee of the Board of Directors monitors the relationship between the pay our executive officers receive and the pay our non-managerial employees receive. During 2021 and 2020, the compensation for our CEO was approximately 28 and 25 times, respectively, the compensation of our median employee.

We believe that a significant portion of an executive's pay should be at risk in the form of performance-based incentive awards that are only paid if the individual and company performance targets are met. For 2021, approximately 79 percent of the targeted compensation of our CEO and about 63 percent of the targeted compensation of our other named executive officers is at risk in the form of performance-based incentive awards. Our Board of Directors establishes the metrics and targets for these incentive awards, based upon advice from the Board of Directors' independent compensation consultant.

We engage nationally recognized outside compensation and benefits consulting firms to independently evaluate the effectiveness of our compensation and benefits programs and to provide benchmarking against our peers within the industry.

Diversity

We believe a diverse and inclusive workforce adds value to our company and helps us succeed in an ever-changing environment. By embracing diversity and fostering inclusion, we aim to enable each employee, executive, and director to contribute fully to the company. We believe diversity is important because varied perspectives expand our ability to bring unique professional experiences to our business. Diversity in the workforce will be considered when relevant to hiring, promotions, work assignments, or other decisions related to the terms and conditions of employment. Our workforce reflects the relative diversity of our available talent in the communities we serve. Our employment data is tested annually by a third party as part of our Affirmative Action plan development to identify any needed corrective placement goals that are required. This testing determined that there is no current need to establish corrective placement goals in our plan.

Of our total workforce, 28 percent of our employees are female, and 26 percent of our employees in management positions are female, including four of our nine executive officers. Additionally, 2020 Women on Boards has previously recognized our gender diversity, with three females among our eight directors who sit on our board. We have implemented methods to provide pay equity between our female and male employees performing equal or substantially similar work. We have engaged with a third party to review our pay equity between our male and female employees, share the results with our Board of Directors, and take corrective action as necessary. Our most recent study was performed in 2019, with no corrective action required.

Health and Safety

As stewards of critical infrastructure, providers of energy service, and members of the communities we serve, our priority is the health and safety of our employees and customers. Safety and health are considered and integrated into all work activities. We monitor several different key areas relating to safety to review and evaluate our operations, to measure progress, and to enhance compliance with our safety philosophies and policies. These key metrics include the recordable incident rate (number of work-related injuries per 100 employees for a one-year period) and lost time incident rate (number of employees who lost time due to work-related injuries per 100 employees for a one-year period). During the years ended December 31, 2021 and December 31, 2020 our recordable incident rates were 1.64 and 1.36 and lost time incident rates were 0.46 and 0.39 on a company wide basis. Our five-year average safety record for the year ended December 31, 2021 was better than our industry peer group's five-year average.

COVID-19

In response to the COVID-19 pandemic, we implemented a variety of protocols to help slow the spread of the virus, protect both our employees and the communities we serve, and enable us to continue to provide our customers with safe and reliable energy service. This effort, which has continued throughout the pandemic, provides safety and health measures to keep our employees on the job and able to perform their duties.

Specifically, we adopted benefit programs to provide additional paid time off due to pandemic related absences to encourage employees to remain home from work if sick. During the pandemic, we have not had to lay off or furlough any employees. Personal protective equipment was procured and remains available, and enhanced facility cleaning and sanitation protocols have been implemented. We made arrangements for employees that are able to do so to work remotely, and we continue to support this practice as the pandemic progresses. We continue to encourage mask wearing and physical distancing as some employees have strategically returned to main work locations. We continue to contact trace employee illnesses to minimize exposure to co-workers, and employees consistently receive a “Covid Briefing” and other communication tools to keep them informed.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

Executive Officer	Current Title and Prior Employment	Age[1]
Robert C. Rowe	Chief Executive Officer and Director since February 2021; formerly President, Chief Executive Officer and Director since August 2008. Mr. Rowe also serves on the board of directors of a NorthWestern subsidiary.	66
Brian B. Bird	President and Chief Operating Officer since February 2021; formerly Chief Financial Officer since December 2003. Mr. Bird serves on the board of directors of a NorthWestern subsidiary.	59
Crystal D. Lail	Vice President and Chief Financial Officer since February 2021; formerly Vice President and Chief Accounting Officer since April 2020; and formerly Vice President and Controller since October 2015.	43
Michael R. Cashell	Vice President - Transmission since May 2011. Mr. Cashell serves on the board of directors of a NorthWestern subsidiary.	59
Heather H. Grahame	Vice President - General Counsel and Regulatory and Federal Government Affairs since January 2018; formerly Vice President and General Counsel since August 2010.	66
John D. Hines	Vice President - Supply and Montana Government Affairs since January 2018; formerly Vice President - Supply since May 2011.	63
Curtis T. Pohl	Vice President - Distribution since May 2011. Mr. Pohl serves on the board of directors of a NorthWestern subsidiary.	57
Bobbi L. Schroeppel	Vice President - Customer Care, Communications and Human Resources since May 2009.	53
Jeanne M. Vold	Vice President - Technology since February 2021; formerly Business Technology Officer since 2012.	55

(1) As of February 4, 2022.

Officers are elected annually by, and hold office at the pleasure of the Board of Directors (Board), and do not serve a “term of office” as such.

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 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 cases, our cost tracking mechanisms are a significant component of how we recover our costs. Trackers can also be highly contested dockets and, as with a rate case, there is no guarantee that the applicable regulatory commission will approve our request to recover costs. We have recently received, and may in the future receive, unfavorable rulings from the MPSC. For example, on December 2, 2021, the MPSC issued a final order rejecting our request to reset the PCCAM Base revenue amount outside of a formal rate case, 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 case. 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, DGGS, 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 case is fully briefed and we expect a decision from the court by the end of the first quarter of 2022. If the preapproval statute is found unconstitutional, there will be no explicit statutory mechanism that facilitates advanced approval of generating resource selection. Preapproval can affect credit ratings by reducing risk. The less risk that NorthWestern is perceived to face, the stronger its credit rating. An MPSC decision granting preapproval reduces risk and often ultimately results in lower debt costs and lower rates paid by customers. A decision by the MPSC also enables NorthWestern to take a more orderly approach to financing, which can also result in lower debt costs that benefit customers. The MPSC provides comments on our resource plan that we file every two to three years, but it does not provide a review and approval of this planning.

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. 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 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, 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, methane fees, the Clean Electricity Performance Program, and Build Back Better Act. 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 widely 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 demonstrated by the recently proposed methane emission regulations from the EPA. 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 Montana Environmental Information Center against the owners and operator of Colstrip, the owners of Units 1 and 2 agreed to shut down those units no later than July 2022. In January 2020, the owners of Units 1 and 2 closed those two units. We do not have ownership in Units 1 and 2, and decisions regarding 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 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 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. We would expect to incorporate any reduction in revenue in our next general electric rate filing, resulting in lower revenue credits to certain customers.

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. As a result of the Washington legislation, four of the six joint owners of Units 3 and 4 requested the operator prepare a 2021 budget reflecting closure of Units 3 and 4 by 2025, and alternately a closure of Unit 3 by 2025 and a closure of Unit 4 by 2027. Differing viewpoints on closure dates delayed approval of the 2021 budget, until it was approved on March 22, 2021. Budgeting for 2022 was also initially delayed, with the same four joint owners demanding substantial budget reductions. Ultimately agreement was reached and a budget approved on January 21, 2022. Such budgeting pressures may result in future budgets that may not be sufficient to maintain the reliability of Units 3 and 4.

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 (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 Arbitration has given rise to three lawsuits, concerning the number of arbitrators, the venue and the applicable arbitration laws. The four joint owners from the Pacific Northwest assert 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 Montana Senate Bill 265, which requires the Arbitration must be conducted, with three arbitrators, in Montana and pursuant to the Montana Uniform Arbitration Act. The three initiated lawsuits do not make direct financial demands, and instead, are intended to address issues related to process for the 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.

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

Increased risks of regulatory penalties could negatively impact our business.

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

Additionally, the Pipeline and Hazardous Materials Safety Administration, Occupational Safety and Health Administration and other federal 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 several impacts, including increasing the likelihood and frequency that we will be required to reduce output from owned generation resources and that we will need to upgrade or build additional transmission facilities to serve QF projects. Either of these results would increase costs to customers. Further, balancing load and power generation on our system is challenging, and we expect that operational costs will increase as a result of integration of these intermittent, non-dispatchable generation projects. If we are unable to timely recover those costs, 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

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.

The financial impact of the COVID-19 pandemic eased during 2021, but 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. 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 it, or a similar widespread public health concern, could in the future as a result of, 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.

For similar reasons, the COVID-19 pandemic has caused adverse impacts on our suppliers, their manufacturers and the overall global supply chain. Accordingly, we have experienced areas of increased costs and delays in obtaining certain supplies and services timely. 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.

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, 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.

In addition, the Biden Administration is seeking to require broad categories of employees to be fully vaccinated against COVID-19 through an OSHA Emergency Temporary Standard (ETS), and through Executive Order 14042. The OSHA ETS provides, generally, that all employers with 100 or more employees require that all workers be vaccinated or undergo weekly COVID-19 testing. On January 13, 2022, the U.S. Supreme Court issued an order halting the ETS's implementation and enforcement while the U.S. Court of Appeals for the Sixth Circuit reviews the ETS on its merits. On January 25, 2022, OSHA withdrew the ETS. 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. The Executive Order did not apply to all government contracts and we determined that the Executive Order did not apply to ours. On December 7, 2021, the U.S. District Court for the Southern District of Georgia issued an injunction, halting the enforcement of this Executive Order nationwide and that determination has been appealed to the U.S. Court of Appeals for the 11th Circuit. On January 21, 2022, the U.S. District Court clarified its December 7, 2021 Order, stating that the injunction applies only to the vaccine mandate and not to other COVID-related requirements such as masking and social distancing. As the OSHA ETS has been withdrawn and Executive Order 14042 does not apply to our existing contracts, we are not required to implement either at this time. However, our obligation to comply with Executive Order 14042 could change in the future depending on the execution of new federal contracts and the ultimate resolution of court challenges to that Order.

Any such workforce implications, significant supply chain disruptions, 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.

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, 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 either from trees or 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.

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 adapt and the risk of cyber-based attacks is heightened with many of our employees working and accessing our technology infrastructure remotely as a result of the COVID-19 pandemic. 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, 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.

There is also a concern that the physical risks of climate change could include changes in weather conditions, such as changes in the amount or type of precipitation and extreme weather events. Climate change and the costs that may be associated with its impacts have the potential to affect our business in many ways, including increasing the cost incurred in providing electricity and natural gas, impacting the demand for and consumption of electricity and natural gas (due to change in both costs and weather patterns), and affecting the economic health of the regions in which we operate.

Extreme weather conditions, 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 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, 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.

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

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. Moody's Investors Service placed us on negative outlook in our 2021 review process. Certain of our credit agreements and other credit arrangements with counterparties require us to provide collateral in the form of letters of credit or cash to support our obligations if we fall below investment grade. Also, a downgrade below investment grade could hinder our ability to raise capital on favorable terms and would increase our borrowing costs. Higher interest rates on borrowings with variable interest rates could also have an adverse effect on our results of operations.

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

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

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

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

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None

ITEM 2. PROPERTIES

Our material properties include electric generating facilities, electric transmission and distribution lines, and natural gas production, transmission and distribution lines, which are described in Item 1 under Electric Operations and Natural Gas Operations. Substantially all of our Montana electric and natural gas assets are subject to the lien of our Montana First Mortgage Bond indenture. Substantially all of our South Dakota and Nebraska electric and natural gas assets are subject to the lien of our South Dakota Mortgage Bond indenture.

ITEM 3. LEGAL PROCEEDINGS

We discuss details of our legal proceedings in Note 18 - Commitments and Contingencies, to the Consolidated Financial Statements. Some of this information is about costs or potential costs that may be material to our financial results.

ITEM 4. MINE SAFETY DISCLOSURES

None

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock, which is traded under the ticker symbol NWE, is listed on the Nasdaq Stock Market. As of February 4, 2022, there were approximately 1,166 common stockholders of record.

ITEM 6. [RESERVED]

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following includes a discussion of our results of operations and cash flows for the year ended December 31, 2021 compared to the year ended December 31, 2020, on both a consolidated basis and on a segment basis. For a discussion of our financial results and cash flows for the year ended December 31, 2020 compared with the year ended December 31, 2019, 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, 2020.

This discussion should be read in conjunction with our Consolidated Financial Statements and related notes contained elsewhere in this Annual Report on Form 10-K. For additional information related to our segments, see Note 20 - Segment and Related Information, to the Consolidated Financial Statements.

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 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 Consolidated Statements of Income. The following discussion includes a reconciliation of Utility Margin to Gross Margin, the most directly comparable GAAP measure.

Management believes 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. As you read this discussion and analysis, refer to our Consolidated Statements of Income, which present the results of our operations for 2021, 2020 and 2019. Following is a discussion of our strategy and significant trends.

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 integrate even more renewables, 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.

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.

In 2021, approximately 56 percent of our retail needs originated from carbon-free resources, compared to approximately 40 percent for the total U.S. electric power industry. In December 2019, we announced a commitment to reduce the carbon intensity of our electric energy portfolio for Montana by 90 percent by 2045 as compared with our 2010 carbon intensity as a baseline. Since 2010, we have already reduced the carbon intensity of our energy generation in Montana by more than 50 percent. Further, as part of our continued efforts in environmental stewardship, we are developing a comprehensive company-wide carbon reduction plan we intend to announce during 2022. Our vision for the future builds on the progress we have made, including our hydroelectric system in Montana, which is 100 percent carbon free and is readily available capacity. For us, wind generation is a close second and continues to grow. While utility-scale solar energy has not been a significant portion of our energy mix today, we recently entered into two 80-megawatt solar power purchase agreements with two projects that are expected to begin delivering energy to our Montana customers in 2022. We expect solar to further evolve along with advances in energy storage. We are committed to working with our customers and communities to help them achieve their sustainability goals and add new technology on our system.

HOW WE PERFORMED IN 2021 COMPARED TO OUR 2020 RESULTS

Consolidated net income in 2021 was $186.8 million as compared with $155.2 million in 2020. This increase was primarily due to higher Montana transmission loads and rates, favorable weather, higher commercial demand as compared to the prior period which was impacted by COVID-19 pandemic related shutdowns, the prior period disallowance of supply costs, and a favorable electric QF liability adjustment as compared with the prior period, partly offset by higher operating costs, non-recoverable Montana electric supply costs, and income tax expense.

	Year Ended December 31, 2021 vs. 2020		
	Income Before Income Taxes	Income Tax Benefit (Expense)	Net Income
		(in millions)	
Year ended December 31, 2020	$ 144.2	$ 11.0	$ 155.2
Items increasing (decreasing) net income:			
Higher Montana electric transmission revenue	25.1	(6.4)	18.7
Higher electric retail volumes	17.1	(4.3)	12.8
Prior period disallowance of supply costs	9.4	(2.4)	7.0
Electric QF liability adjustment	4.4	(1.1)	3.3
Higher Montana natural gas volumes	1.3	(0.3)	1.0
Higher income tax expense	—	(2.1)	(2.1)
Higher operating costs impacting net income	(15.0)	3.8	(11.2)
Higher depreciation and depletion	(7.8)	2.0	(5.8)
Higher non-recoverable Montana electric supply costs	(5.3)	1.3	(4.0)
Other	16.8	(4.9)	11.9
Year ended December 31, 2021	$ 190.2	$ (3.4)	$ 186.8
Change in Net Income			$ 31.6

SIGNIFICANT TRENDS AND REGULATION

Electric Resource Planning - Montana

A shortage of critical 24/7 power capacity resources is jeopardizing reliability in the Western United States. The accredited capacity of our Montana portfolio of owned and long-term contracted electric generation resources covered approximately 70 percent of our 2021 peak electric requirements, with the remaining capacity shortfall, including reserve margin, covered through market purchases. A significant number of base-load generation facilities in the state and region have been retired or are scheduled to be retired in the next several years, which may impair grid and customer service reliability and increase volatility in market prices. Accordingly, our continued exposure to market purchases is an increasing risk to the availability and affordability of service for our Montana customers.

Future Integrated Resource Planning - We expect to submit an updated integrated resource plan by the end of 2022 or early 2023, 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 18 - Commitments and Contingencies) may affect the timing of the submission of this plan.

We remain concerned regarding an overall lack of capacity in the region and our resource adequacy deficit in the near term based on our projections of load by 2025, as a risk to customer reliability and affordability. As such, in addition to the 300 MWs (325 MWs nameplate) of accredited capacity additions resulting from the prior integrated resource plan as discussed below, we have reduced our exposure to our projected 725 MW shortfall of accredited capacity by 2025 through a combination of executing short and medium term cost-competitive agreements for 225 MWs of existing capacity in the region. We also expect to have an incremental 200 MWs of capacity resource additions in this period through a combination of new and renewed QF contracts and increases to the forecasted capacity accreditation of existing intermittent resources. This reduction of risk in the near term allows for clarity on the Colstrip arbitration, further development in the western markets, and ongoing technological changes.

January 2020 Request for Proposal (RFP) - To help meet our critical power capacity and peak demands, as a result of our all-source competitive solicitation request for long-term capacity resources we entered into contracts for 325 MWs of dispatchable capacity resources. These contracts include:

- A 5-year power purchase agreement for 100 MWs of firm capacity and energy products originating predominately from the British Columbia Hydro system starting in January 2023 (Powerex Transaction);
- A 20-year agreement to purchase capacity and ancillary services produced from the 50 MW Beartooth Battery project near Billings, Montana, expected to be online by late 2023 or early 2024; and
- Contracts for the construction of a nameplate capacity 175 MW natural gas-fired generation plant in Montana, at a cost of approximately $275 million, including AFUDC, which we will own.

We initially filed an application with the MPSC for advanced approval to construct the 175 MW generation plant in Montana. We subsequently made the difficult decision to withdraw our application in order to meet the targeted commercial operation date of the plant. The upheaval in the construction market and, specifically, timely availability of critical components and escalating labor and construction costs due to the COVID-19 pandemic, necessitates the flexibility to expend capital and make commercial decisions in advance of the timeline established by the MPSC approval docket. The schedule is expected to allow the plant to serve our Montana customers during the 2023-2024 winter season.

On October 21, 2021, the Montana Environmental Information Center and the Sierra Club filed a lawsuit in Montana State Court, against the Montana Department of Environmental Quality (MTDEQ) and us, alleging the environmental review of our Yellowstone County plant site project was unlawful. This lawsuit could delay the project if the Montana State Court were to require a full Environmental Impact Study regarding the project, set aside the air quality permit granted for the Yellowstone County project, or determine that the underlying environmental statute violates the Montana Constitutional guarantee of a "clean and healthful environment."

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. The MPSC has not yet established a procedural schedule in this docket but we anticipate an MPSC decision in the fourth quarter of 2022. Our application is subject to the risk of the District Court agreeing with the plaintiffs in the litigation challenging the constitutionality of the preapproval statute.

Electric Resource Supply - South Dakota

Construction on our new Bob Glanzer Generating Station is nearing completion. The 58 MW natural gas plant in Huron, South Dakota is expected to be online early in the second quarter of 2022 with total construction costs of approximately $80 million ($77.8 million incurred through December 31, 2021).

During the third quarter of 2021, we discontinued our plans to build a 30-40 MW natural gas plant near Aberdeen, South Dakota. Originally expected to be a $60 million project to be in service early in 2024, we were experiencing significant increases in estimated construction cost as a result of global supply chain challenges. As a result of the project discontinuance, we recorded a $1.6 million pre-tax charge for the write-off of preliminary construction costs. Our energy resource plans continue to identify portfolio requirements including potential investments resulting from a completed competitive solicitation process in South Dakota. We expect to file an updated integrated resource plan in late 2022.

Impact of Fuel and Purchase Power Costs

Montana PCCAM - In April 2021, we submitted a filing with the MPSC requesting approval to increase the PCCAM Base forecasted costs used to develop rates for the recovery of electric power costs by approximately $17 million, or potentially a greater increase to reflect current market prices and new capacity contracts. On June 29, 2021, the MPSC approved our request for interim rates reflecting the $17 million increase, subject to refund. The Montana Consumer Counsel (MCC) filed a motion arguing that the PCCAM Base cannot be updated except in a general rate case and asked the MPSC to dismiss the application. On October 5, 2021, the MPSC voted to grant the MCC's motion to dismiss and on December 2, 2021, the MPSC issued a final order dismissing our application.

In 2021, PCCAM costs exceeded base revenues by approximately $54.1 million, which are allocated 90% to Montana customers and 10% to shareholders. As a result, we deferred $48.7 million of costs during 2021 to be collected from customers (90% of the costs above base) and recorded a reduction in pre-tax earnings of $5.4 million (10% of the variance). These increased costs are not reflected in customer bills and recovered until the subsequent power cost adjustment year, adversely affecting our cash flows and liquidity. We expect to address an adjustment to the PCCAM base in our upcoming Montana electric general rate filing.

Regulatory Update

General Rate Filing – Rate cases 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. We anticipate making a Montana electric general rate filing (2021 test year) in mid-2022.

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 has initiated a routine audit of NorthWestern Corporation for the period of January 1, 2018 to the present to evaluate our compliance with FERC accounting and financial reporting requirements. We have responded to several sets of data requests as part of the audit process. An audit report has not yet been received from FERC, but is expected during the first quarter of 2022. Management is unable to predict the outcome or timing of the final resolution of the audit.

Supply Chain 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.

See "Electric Resource Supply - South Dakota" section above for discussion of supply chain challenges that have already impacted our business activities. Also, as we developed our forecast of capital expenditures, we estimate that these supply chain challenges have, thus far, increased our 2022 capital spend by approximately 2 percent, and it may go higher.

Financing Activities

We anticipate financing our ongoing maintenance and capital programs with a combination of cash flows from operations, first mortgage bonds and equity issuances. See "Liquidity and Capital Resources" for additional information regarding our debt and equity financing activities. Financing plans are subject to change, depending on capital expenditures, regulatory outcomes, internal cash generation, market conditions and other factors.

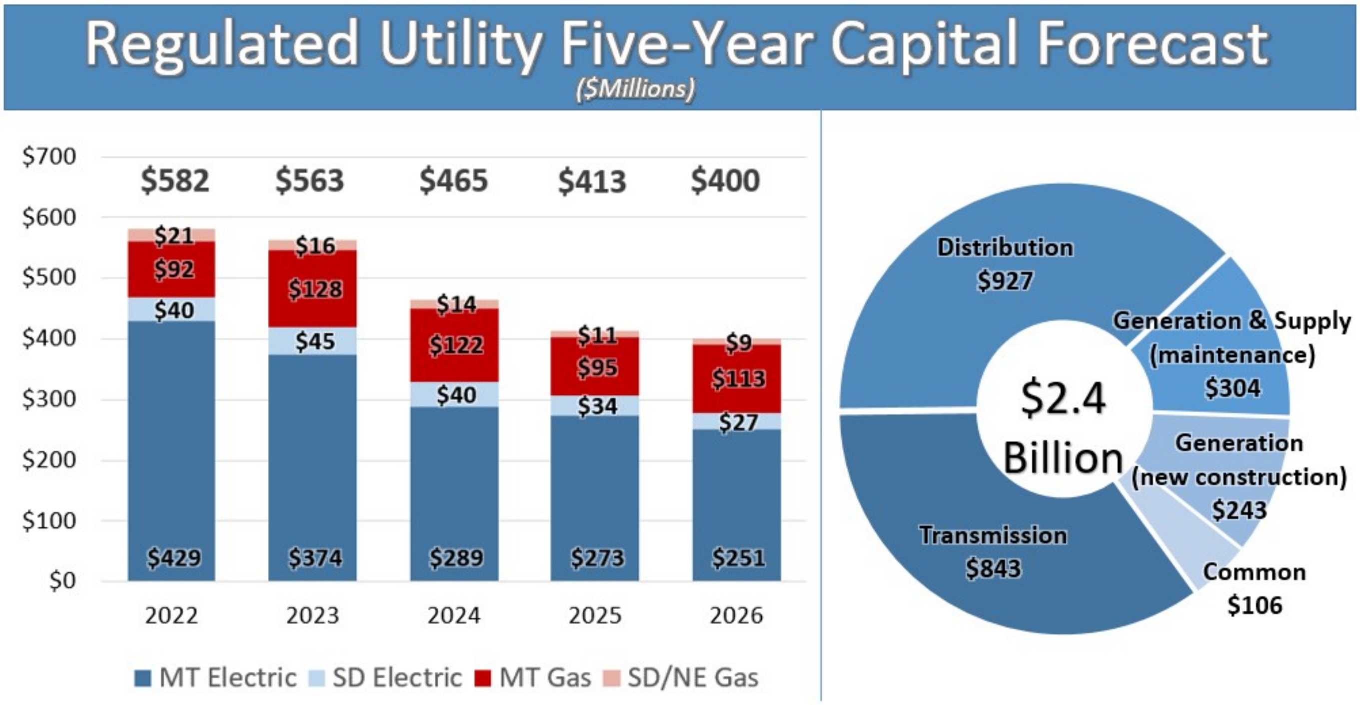
Fire Mitigation

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 are proactively seeking to mitigate wildfire risk through development of a comprehensive Fire Mitigation Plan addressing four key areas: situational awareness, operational practices, system assessment repair and hardening programs, and public safety and communications. This plan builds upon several key initiatives that were initiated and executed over the past several years including our transmission and distribution system infrastructure programs and our hazard tree removal program. 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 expect to include a request for costs associated with the plan in our 2022 Montana electric rate filing.

SIGNIFICANT INFRASTRUCTURE INVESTMENTS AND INITIATIVES

Our estimated capital expenditures for the next five years, including our electric and natural gas transmission and distribution and electric generation infrastructure investment plan, are as follows (in millions):



Electric Supply Resource Plans - Our energy resource plans identify portfolio resource requirements including potential investments. As a result of a competitive solicitation process in Montana, we have included approximately $275 million of capital in our projections above to construct a 175 MW natural gas plant to be on line during the 2023 or 2024 winter season.

Distribution and Transmission Modernization and Maintenance - The primary goals of our infrastructure investments are to reverse the trend in aging infrastructure, maintain reliability, proactively manage safety, build capacity into the system, and prepare our network for the adoption of new technologies. We are taking a proactive and pragmatic approach to replacing these assets while also evaluating the implementation of additional technologies to prepare the overall system for smart grid applications. Beginning in 2021, and continuing through 2025, we expect to install automated metering infrastructure in Montana at a total cost of approximately $125 million, of which, $100 million remains and is reflected in the five year capital forecast above.

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

Year Ended December 31, 2021 Compared with Year Ended December 31, 2020

Consolidated net income in 2021 was $186.8 million as compared with $155.2 million in 2020, an increase of $31.6 million. As described in more detail below, this increase was primarily due to higher Montana transmission loads and rates, favorable weather, higher commercial demand as compared to the prior period due to the COVID-19 pandemic related shutdowns, the prior period disallowance of supply costs, and a favorable electric QF liability adjustment as compared with the prior period, partly offset by higher operating costs, non-recoverable Montana electric supply costs, and income tax expense.

Consolidated gross margin in 2021 was $377.7 million as compared with $330.3 million in 2020, an increase of $47.4 million, or 14.4 percent. This increase was primarily due to higher Montana transmission loads and rates, favorable weather, higher commercial demand as compared to the prior period due to the COVID-19 pandemic related shutdowns, the prior period disallowance of supply costs, a favorable electric QF liability adjustment as compared with the prior period, and lower property and other taxes, partly offset by higher operating and maintenance expense, depreciation and depletion, and Montana non-recoverable electric supply costs.

	Electric		Natural Gas		Total	
	2021	2020	2021	2020	2021	2020
	(in millions)					
Reconciliation of gross margin to utility margin:						
Operating Revenues	$1,052.2	$ 940.8	$ 320.1	$ 257.9	$1,372.3	$1,198.7
Less: Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	294.8	236.6	130.7	69.6	425.5	306.2
Less: Operating and maintenance	156.4	149.2	51.9	53.8	208.3	203.0
Less: Property and other taxes	134.9	140.6	38.5	38.9	173.4	179.5
Less: Depreciation and depletion	154.6	148.0	32.8	31.7	187.4	179.7
Gross Margin	**311.5**	**266.4**	**66.2**	**63.9**	**377.7**	**330.3**
Operating and maintenance	156.4	149.2	51.9	53.8	208.3	203.0
Property and other taxes	134.9	140.6	38.5	38.9	173.4	179.5
Depreciation and depletion	154.6	148.0	32.8	31.7	187.4	179.7
Utility Margin[(1)]	**$ 757.4**	**$ 704.2**	**$ 189.4**	**$ 188.3**	**$ 946.8**	**$ 892.5**

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

	Year Ended December 31,			
	2021	2020	Change	% Change
	(in millions)			
Utility Margin				
Electric	$ 757.4	$ 704.2	$ 53.2	7.6 %
Natural Gas	189.4	188.3	1.1	0.6
Total Utility Margin[(1)]	**$ 946.8**	**$ 892.5**	**$ 54.3**	**6.1 %**

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

Consolidated utility margin in 2021 was $946.8 million as compared with $892.5 million in 2020, an increase of $54.3 million, or 6.1 percent.

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

	Utility Margin 2021 vs. 2020	
Utility Margin Items Impacting Net Income		
Higher transmission rates and demand due to market conditions and pricing and the recognition of approximately $4.7 million of deferred interim revenues	$	25.1
Higher electric retail volumes		17.1
Prior period MPSC disallowance of supply costs		9.4
Electric QF liability adjustment		4.4
Higher natural gas retail volumes		1.3
Higher non-recoverable Montana electric supply costs compared to the prior period		(5.3)
Reduction of rates from the step down of our Montana gas production assets		(1.2)
Other		5.1
Change in Utility Margin Impacting Net Income		**55.9**
Utility Margin Items Offset Within Net Income		
Property taxes recovered in revenue, offset in property tax expense		(4.8)
Higher revenue from lower production tax credits, offset in income tax expense		2.5
Gas production taxes recovered in revenue, offset in property and other taxes		0.5
Operating expenses recovered in revenue, offset in operating and maintenance expense		0.2
Change in Items Offset Within Net Income		**(1.6)**
Increase in Consolidated Utility Margin[(1)]	**$**	**54.3**

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

Higher electric retail volumes were driven by warmer summer weather in both Montana and South Dakota, customer growth, and increased commercial volume as compared to the prior year due to the COVID-19 pandemic related shutdowns, partly offset by warmer overall winter weather in Montana and South Dakota. The higher natural gas retail volumes were due to improved Montana commercial volumes as compared to the prior year due to the COVID-19 pandemic related shutdowns and customer growth, partly offset by overall warmer weather in all jurisdictions. In addition, the 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 $7.5 million gain in 2021, as compared with a $3.1 million gain for the same period in 2020, due to the combination of:

- A $2.6 million favorable reduction in costs for the current contract year to record the annual adjustment for actual output and pricing as compared with a $0.9 million favorable reduction in costs in the prior period;
- A negative adjustment, increasing the QF liability by $2.1 million, reflecting annual actual contract price escalation, which was more than previously estimated, compared to a favorable adjustment of $2.2 million in the prior year due to lower actual price escalation; and
- A favorable adjustment of approximately $7.0 million decreasing the QF liability associated with a one-time clarification in contract term.

	Year Ended December 31,						
	2021		2020		Change		% Change
	(in millions)						
Operating Expenses (excluding fuel, purchased supply and direct transmission expense)							
Operating and maintenance	$	208.3	$	203.0	$	5.3	2.6 %
Administrative and general		101.9		94.1		7.8	8.3
Property and other taxes		173.4		179.5		(6.1)	(3.4)
Depreciation and depletion		187.5		179.6		7.9	4.4
	$	**671.1**	**$**	**656.2**	**$**	**14.9**	**2.3 %**

Consolidated operating and maintenance expenses were $208.3 million in 2021, as compared with $203.0 million in 2020. Primary components of the change include the following (in millions):

	Operating & Maintenance Expenses 2021 vs. 2020	
Operating & Maintenance Expenses Impacting Net Income		
Higher maintenance at our electric generation facilities	$	4.6
Higher labor and benefits expenses due to increased compensation and medical costs		4.7
Write off of preliminary construction costs		1.6
Other		0.5
Change in Items Impacting Net Income		**11.4**
Operating & Maintenance Expenses Offset Within Net Income		
Pension and other postretirement benefits, offset in other income		(6.3)
Operating expenses recovered in trackers, offset in revenue		0.2
Change in Items Offset Within Net Income		**(6.1)**
Increase in Operating and Maintenance Expenses	**$**	**5.3**

The write off of preliminary construction costs is associated with the 30-40MW flexible natural gas plant near Aberdeen, South Dakota.

Consolidated administrative and general expense was $101.9 million in 2021, as compared with $94.1 million in 2020. Primary components of the change include the following (in millions):

	Administrative & General Expenses 2021 vs. 2020	
Administrative & General Expenses Impacting Net Income		
Higher technology implementation and maintenance expenses	$	2.4
Higher litigation expenses		2.0
Higher insurance expenses		1.5
Higher labor and benefits expenses due to increased compensation and medical costs		1.0
Decrease in uncollectible accounts expense		(4.5)
Other		1.2
Change in Items Impacting Net Income		**3.6**
Administrative & General Expenses Offset Within Net Income		
Non-employee directors deferred compensation, offset in other income		4.2
Change in Items Offset Within Net Income		**4.2**
Increase in Administrative & General Expenses	**$**	**7.8**

Uncollectible accounts expense decreased due to collections of previously written off amounts in the current period. In the second quarter of 2020, we voluntarily suspended service disconnections for non-payment, to help customers who may be financially impacted by the COVID-19 pandemic.

Property and other taxes were $173.4 million in 2021, as compared with $179.5 million in 2020. This decrease was primarily due to lower estimated property valuations in Montana partly offset by plant additions.

Depreciation and depletion expense was $187.5 million in 2021, as compared with $179.6 million in 2020. This increase was primarily due to plant additions.

Consolidated operating income in 2021 was $275.7 million as compared with $236.2 million in 2020. This increase was primarily driven by higher Montana transmission loads and rates, favorable weather, higher commercial demand as compared to the prior period due to the COVID-19 pandemic related shutdowns, the prior period disallowance of supply costs, a favorable electric QF liability adjustment as compared with the prior period, and lower property and other taxes, partly offset by higher operation and maintenance expense, depreciation expense, and administrative and general expense.

Consolidated interest expense in 2021 was $93.7 million, as compared with $96.8 million in 2020. This decrease was primarily due to higher capitalization of AFUDC and lower FERC deferrals, partly offset by higher borrowings.

Consolidated other income in 2021 was $8.3 million, as compared with $4.9 million in 2020. This increase was primarily due to higher capitalization of AFUDC and higher interest income, partly offset by $2.1 million in items offset in operating expenses. Items offset in operating expenses include a $6.3 million increase in pension expenses and a $4.2 million increase in the value of deferred shares held in trust for non-employee directors deferred compensation.

Consolidated income tax expense in 2021 was $3.4 million, as compared to an income tax benefit of $11.0 million in 2020. Our effective tax rate for the twelve months ended December 31, 2021 was 1.8 percent as compared with (7.6) percent for the same period of 2020. We currently estimate our effective tax rate will range between 0.0 percent to 3.0 percent in 2022. The effective tax rate is expected to gradually increase to approximately 15 percent by 2026.

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

	Year Ended December 31,			
	2021		2020	
Income Before Income Taxes	$ 190.3		$ 144.2	
Income tax calculated at federal statutory rate	40.0	21.0 %	30.3	21.0 %
Permanent or flow through adjustments:				
State income, net of federal provisions	0.4	0.1	(1.5)	(1.1)
Flow-through repairs deductions	(21.9)	(11.5)	(23.8)	(16.5)
Production tax credits	(11.5)	(6.1)	(13.1)	(9.1)
Plant and depreciation of flow through items	(0.9)	(0.6)	0.1	0.1
Amortization of excess deferred income taxes (DIT)	(0.6)	(0.3)	(1.0)	(0.7)
Prior year permanent return to accrual adjustments	0.0	0.0	(1.7)	(1.2)
Other, net	(2.1)	(0.8)	(0.3)	(0.1)
	(36.6)	(19.2)	(41.3)	(28.6)
Income Tax Expense (Benefit)	$ 3.4	1.8 %	$ (11.0)	(7.6)%

ELECTRIC OPERATIONS

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.

Year Ended December 31, 2021 Compared with Year Ended December 31, 2020

	Revenues		Change		Megawatt Hours (MWH)		Avg. Customer Counts	
	2021	2020	$	%	2021	2020	2021	2020
	(in thousands)							
Montana	$ 334,581	$ 320,792	$ 13,789	4.3 %	2,729	2,635	311,922	307,390
South Dakota	65,429	66,603	(1,174)	(1.8)	571	583	50,805	50,646
Residential	**400,010**	**387,395**	**12,615**	**3.3**	**3,300**	**3,218**	**362,727**	**358,036**
Montana	356,669	338,269	18,400	5.4	3,176	3,036	71,605	70,145
South Dakota	102,475	101,095	1,380	1.4	1,092	1,073	12,795	12,802
Commercial	**459,144**	**439,364**	**19,780**	**4.5**	**4,268**	**4,109**	**84,400**	**82,947**
Industrial	37,866	36,819	1,047	2.8	2,448	2,615	77	78
Other	32,084	31,833	251	0.8	175	173	6,333	6,333
Total Retail Electric	**$ 929,104**	**$ 895,411**	**$ 33,693**	**3.8 %**	**10,191**	**10,115**	**453,537**	**447,394**
Regulatory amortization	34,395	(11,455)	45,850	(400.3)				
Transmission	82,628	51,539	31,089	60.3				
Wholesale and Other	6,055	5,320	735	13.8				
Total Revenues	**$1,052,182**	**$ 940,815**	**$ 111,367**	**11.8 %**				
Fuel, purchased supply and direct transmission expense[1]	**294,820**	**236,581**	**58,239**	**24.6**				
Utility Margin[2]	**$ 757,362**	**$ 704,234**	**$ 53,128**	**7.5 %**				

(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.

	Cooling Degree Days			2021 as compared with:	
	2021	2020	Historic Average	2020	Historic Average
Montana	635	398	417	60% warmer	52% warmer
South Dakota	1,034	879	733	18% warmer	41% warmer

	Heating Degree Days			2021 as compared with:	
	2021	2020	Historic Average	2020	Historic Average
Montana	7,217	7,304	7,557	1% warmer	4% warmer
South Dakota	6,758	7,445	7,696	9% warmer	12% warmer

The following summarizes the components of the changes in electric utility margin for the years ended December 31, 2021 and 2020 (in millions):

		Utility Margin 2021 vs. 2020
Utility Margin Items Impacting Net Income		
Higher transmission rates and demand due to market conditions and pricing and the recognition of approximately $4.7 million of deferred interim revenues	$	25.1
Higher retail volumes		17.1
Prior period disallowance of supply costs		9.4
QF liability adjustment		4.4
Higher non-recoverable Montana electric supply costs compared to the prior period		(5.3)
Other		3.3
Change in Utility Margin Impacting Net Income		**54.0**
Utility Margin Items Offset Within Net Income		
Property taxes recovered in revenue, offset in property tax expense		(4.0)
Higher revenue from lower production tax credits, offset in income tax expense		2.5
Operating expenses recovered in revenue, offset in operating and maintenance expense		0.6
Change in Items Offset Within Net Income		**(0.9)**
Increase in Utility Margin[1]	**$**	**53.1**

(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 both Montana and South Dakota, customer growth, and increased commercial volume as compared to the prior year due to the COVID-19 pandemic related shutdowns, partly offset by warmer overall winter weather in Montana and South Dakota. The 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 $7.5 million gain in 2021, as compared with a $3.1 million gain for the same period in 2020, due to the combination of:

- A $2.6 million favorable reduction in costs for the current contract year to record the annual adjustment for actual output and pricing as compared with a $0.9 million favorable reduction in costs in the prior period;
- A negative adjustment, increasing the QF liability by $2.1 million, reflecting annual actual contract price escalation, which was more than previously estimated, compared to a favorable adjustment of $2.2 million in the prior year due to lower actual price escalation; and
- A favorable adjustment of approximately $7.0 million decreasing the QF liability 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 OPERATIONS

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.

Year Ended December 31, 2021 Compared with Year Ended December 31, 2020

	Revenues		Change		Dekatherms		Avg. Customer Counts	
	2021	2020	$	%	2021	2020	2021	2020
	(in thousands)							
Montana	$ 126,043	$ 103,457	22,586	21.8 %	13,885	13,893	179,637	177,335
South Dakota	26,596	21,547	5,049	23.4	2,834	2,993	41,079	40,612
Nebraska	20,964	16,861	4,103	24.3	2,480	2,561	37,603	37,576
Residential	**173,603**	**141,865**	**31,738**	**22.4**	**19,199**	**19,447**	**258,319**	**255,523**
Montana	64,681	51,349	13,332	26.0	7,446	7,166	24,927	24,497
South Dakota	19,131	14,316	4,815	33.6	2,744	3,003	6,896	6,895
Nebraska	11,371	8,066	3,305	41.0	1,755	1,784	4,963	4,974
Commercial	**95,183**	**73,731**	**21,452**	**29.1**	**11,945**	**11,953**	**36,786**	**36,366**
Industrial	1,134	840	294	35.0	135	122	229	231
Other	1,417	923	494	53.5	187	152	166	153
Total Retail Gas	**$ 271,337**	**$ 217,359**	**$ 53,978**	**24.8 %**	**31,466**	**31,674**	**295,500**	**292,273**
Regulatory amortization	12,048	5,043	7,005	138.9				
Wholesale and other	36,749	35,453	1,296	3.7				
Total Revenues	**$ 320,134**	**$ 257,855**	**$ 62,279**	**24.2 %**				
Fuel, purchased supply and direct transmission expense(1)	**130,728**	**69,609**	**61,119**	**87.8**				
Utility Margin(2)	**$ 189,406**	**$ 188,246**	**$ 1,160**	**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.

	Heating Degree Days			2021 as compared with:	
	2021	2020	Historic Average	2020	Historic Average
Montana	7,390	7,505	7,775	2% warmer	5% warmer
South Dakota	6,758	7,445	7,696	9% warmer	12% warmer
Nebraska	5,632	5,676	6,354	1% warmer	11% warmer

The following summarizes the components of the changes in natural gas utility margin for the years ended December 31, 2021 and 2020 (in millions):

	Utility Margin 2021 vs. 2020
Utility Margin Items Impacting Net Income	
Higher retail volumes	$ 1.3
Reduction of rates from the step down of our Montana gas production assets	(1.2)
Other	1.8
Change in Utility Margin Impacting Net Income	**1.9**
Utility Margin Items Offset Within Net Income	
Property taxes recovered in revenue, offset in property tax expense	(0.8)
Operating expenses recovered in revenue, offset in operating and maintenance expense	(0.4)
Gas production taxes recovered in revenue, offset in property and other taxes	0.5
Change in Items Offset Within Net Income	**(0.7)**
Increase in Utility Margin(1)	**$ 1.2**

(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.

Higher retail volumes were driven by improved Montana commercial volumes as compared to the prior year due to the COVID-19 pandemic related shutdowns and customer growth, partly offset by overall warmer weather in all jurisdictions.

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 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 December 31, 2021, our total net liquidity was approximately $79.8 million, including $2.8 million of cash, $77.0 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 $286.1 million.

Cash Flows

The primary sources and uses of cash and cash equivalents are summarized in the following condensed statement of cash flows for 2021 and 2020 (in millions):

	Year Ended December 31,	
	2021	2020
Operating Activities		
Net income	$ 186.8	$ 155.2
Non-cash adjustments to net income	187.5	174.3
Changes in working capital	(120.6)	48.1
Other noncurrent assets and liabilities	(33.7)	(25.5)
Cash Provided by Operating Activities	**220.0**	**352.1**
Investing Activities		
Property, plant and equipment additions	(434.3)	(405.8)
Investment in equity securities	(1.5)	—
Cash Used in Investing Activities	**(435.8)**	**(405.8)**
Financing Activities		
Proceeds from issuance of common stock, net	196.2	—
Issuance of long-term debt	99.9	150.0
(Repayments) issuances of short-term borrowings	(100.0)	100.0
Dividends on common stock	(128.5)	(120.4)
Line of credit borrowings (repayments), net	151.0	(67.0)
Financing costs	(0.9)	(2.6)
Other	(0.2)	(1.3)
Cash Provided by Financing Activities	**217.5**	**58.7**
Net Increase in Cash, Cash Equivalents, and Restricted Cash	**$ 1.7**	**$ 5.0**
Cash, Cash Equivalents, and Restricted Cash, beginning of period	$ 17.1	$ 12.1
Cash, Cash Equivalents, and Restricted Cash, end of period	**$ 18.8**	**$ 17.1**

Operating Activities

Cash provided by operating activities totaled $220.0 million for the year ended December 31, 2021 as compared with $352.1 million during 2020. This decrease in operating cash flows is primarily due to a $122.3 million ($80.0 million from electric operations and $42.3 million from natural gas operations) net increase in under collection of energy supply costs from customers in the current period, which includes costs incurred during a February 2021 prolonged cold weather event, the under-collected position of Montana's PCCAM, and a refund of approximately $20.5 million to our FERC regulated customers and approximately $6.1 to our Montana electric retail customers. These reductions were offset in part by an improvement in net income.

As of December 31, 2021, we have under collected our supply costs recovered through tracking mechanisms by approximately $97.8 million. We have various regulatory mechanisms that support our recovery of the energy supply costs incurred by our utilities. Through these mechanisms and the regulatory agreements for recovery of the costs incurred during the February 2021 cold weather event, we anticipate recovering a significant portion of these costs during 2022, improving our cash flows from operations. Conversely, a prolonged spike in energy market prices in our operating jurisdictions, which could be caused by further 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 $435.8 million during the year ended December 31, 2021, as compared with $405.8 million during 2020. Plant additions during 2021 include capital maintenance additions of approximately $314.1 million, and capacity related capital expenditures of approximately $120.2 million. Plant additions during 2020 included capital maintenance additions of approximately $269.5 million, and capacity related capital expenditures of approximately $136.3 million. As discussed above in the "Significant Infrastructure Investments and Initiatives" section, our capital expenditures are forecasted to increase to $582 million in 2022.

Financing Activities

Cash provided by financing activities totaled $217.5 million during 2021 as compared with $58.7 million during 2020. During 2021, the increase in cash provided by financing activities reflected the transactions noted below, which were undertaken primarily to fund capital expenditures in excess of our cash from operations, while maintaining our credit ratings.

We issue debt and equity securities from time to time to refinance retiring debt maturities, reduce balances on our revolving credit facilities, fund capital expenditure programs, maintain credit ratings, and for other general corporate purposes.

In March 2021, we issued and sold $100 million aggregate principal amount of Montana First Mortgage Bonds (the bonds) at a fixed interest rate of 1.00% maturing in March 26, 2024. The net proceeds were used to repay in full our outstanding $100 million term loan that was due April 2, 2021. We may redeem some or all of the bonds at any time in whole, or from time to time in part, at our option, on or after March 26, 2022, at a redemption price equal to 100% of the principal amount of the bonds to be redeemed, plus accrued and unpaid interest on the principal amount of the bonds being redeemed to, but excluding, the redemption date. The bonds are secured by our electric and natural gas assets in Montana and Wyoming.

In April 2021, we entered into an Equity Distribution Agreement with BofA Securities, Inc., CIBC World Markets Corp, Credit Suisse Securities (USA) LLC, and J.P. Morgan Securities LLC, collectively the sales agents, pursuant to which we may offer and sell shares of our common stock from time to time, having an aggregate gross sales price of up to $200.0 million, through an At-the-Market (ATM) offering program, including an equity forward sales component. This is a three-year agreement, expiring on February 11, 2024. During the three months ended December 31, 2021, we issued 46,723 shares of our common stock under the ATM program at an average price of $58.49, for net proceeds of $2.7 million, which is net of sales commissions and other fees paid of less than $0.1 million. During the twelve months ended December 31, 2021, we issued 1,966,117 shares of our common stock under the ATM program at an average price of $63.81, for net proceeds of $124.2 million, which is net of sales commissions and other fees paid of approximately $1.3 million. We do not expect to utilize the ATM program during 2022.

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. The initial forward agreement was for 6.1 million shares with an additional 0.9 million shares exercised at the option of the banking counterparty. Of the total 7.0 million shares of 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.

At December 31, 2021, the forward agreements could have been settled with physical delivery of approximately 5.6 million common shares to the banking counterparty in exchange for cash of $286.1 million. The forward instruments could have also been settled at December 31, 2021, with delivery of approximately $24.4 million of cash or approximately 0.4 million shares of common stock to the counterparty, if we unilaterally elected to net cash or net share settlement, respectively.

The forward price used to determine amounts due at settlement is calculated based on the November 2021 public offering price for our common stock of $53.50, net of underwriting discount, for an initial forward settlement price of $51.895, per share. The initial forward settlement price is increased for the overnight bank funding rate, less a spread of 0.75 percent and less expected dividends on our common stock during the period the instruments are outstanding.

We may settle the agreements at any time up to the maturity date of February 28, 2023. Depending on settlement timing, if we elect to physically settle by delivering shares of common stock, cash proceeds are expected to be approximately $269.8 million to $286.1 million. Forward equity instruments were recognized within stockholders' equity at fair value at the execution of the agreements and will not be subsequently adjusted until settlement.

Cash Requirements and Capital Resources

The Company believes its cash flows from operations, existing borrowing capacity, debt and equity issuances and future rate increases should be sufficient to satisfy its 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 timely recovery for many 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, which is discussed above in the "Significant Infrastructure Investments and Initiatives" section. Our capital expenditures are forecasted to increase to $582 million in 2022, $563 million in 2023, and $465 million in 2024. We anticipate funding capital expenditures through cash flows from operations, available credit sources, debt and equity issuances and future rate increases. 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 entered into in September 2020 and has a maturity date of September 2, 2023. The Credit Facility includes uncommitted features that allow us to request up to two one-year extensions to the maturity date and increase the size by an additional $75 million with the consent of the lenders. The Credit Facility does not amortize and is unsecured. Borrowings may be made at interest rates equal to the Eurodollar rate, plus a margin of 112.5 to 175.0 basis points, or a base rate, plus a margin of 12.5 to 75.0 basis points. A total of ten banks participate in the facility, with no one bank providing more than 13 percent of the total availability.

The following table presents additional information about borrowings under our revolving credit facilities during the year ended December 31, 2021 (in millions):

Amount outstanding at year end	$	373.0
Daily average amount outstanding	$	260.3
Maximum amount outstanding	$	373.0
Minimum amount outstanding	$	171.0

As of February 4, 2022, our availability under our revolving credit facilities was approximately $112.0 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. We do not have any long-term debt maturities in 2022.

We generally 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 described above, during 2021 we entered into a three-year ATM equity offering program whereby we can offer to sell up to $200.0 million of common shares. During 2021 we raised nearly $125 million under the program, but do not anticipate needing to issue equity through this program in 2022. We also initiated a public offering of $373.8 million of our common stock in November 2021. We received approximately $75 million of cash proceeds for a portion of this offering and entered into forward equity agreements for the balance of the shares. We may settle the forward sale agreements at any time up to the maturity date of February 28, 2023. We anticipate physically settling these agreements to meet our equity capital needs for 2022. Depending on settlement timing, if we physically settle by delivering our shares of common stock, cash proceeds are expected to be approximately $269.8 million to $286.1 million.

Credit Ratings

In general, less favorable credit ratings make debt financing more costly and more difficult to obtain on terms that are favorable to us and our customers, may impact our trade credit availability, and could result in the need to issue additional equity securities. Fitch Ratings (Fitch), Moody's Investors Service (Moody's), and S&P Global Ratings (S&P) are independent credit-rating agencies that rate our debt securities. These ratings indicate the agencies' assessment of our ability to pay interest and principal when due on our debt. As of February 4, 2022, our current ratings with these agencies are as follows:

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

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

Contractual Obligations and Other Commitments

We have a variety of contractual obligations and other commitments that require payment of cash at certain specified periods. With the exception of maturities of long-term debt, we anticipate funding these obligations through cash flows from operations. The following table summarizes our contractual cash obligations and commitments as of December 31, 2021. See additional discussion in Note 18 - Commitments and Contingencies to the Consolidated Financial Statements.

	Total	2022	2023	2024	2025	2026	Thereafter
				(in thousands)			
Long-term debt[1]	$ 2,552,660	$ —	$ 517,660	$ 100,000	$ 300,000	$ 105,000	$ 1,530,000
Finance leases	14,772	2,875	3,099	3,337	3,596	1,865	—
Estimated pension and other postretirement obligations[2]	58,805	12,775	11,658	11,658	11,357	11,357	N/A
Qualifying facilities liability[3]	466,872	80,355	82,452	75,113	60,360	55,393	113,199
Supply and capacity contracts[4]	2,640,393	283,212	269,700	221,758	219,443	172,227	1,474,053
Contractual interest payments on debt[5]	1,480,783	88,457	86,270	79,760	70,791	64,701	1,090,804
Commitments for significant capital projects[6]	268,372	192,239	69,533	6,600	—	—	$ —
Total Commitments[7]	$ 7,482,657	$ 659,913	$ 1,040,372	$ 498,226	$ 665,547	$ 410,543	$ 4,208,056

(1) Represents cash payments for long-term debt and excludes $11.2 million of debt discounts and debt issuance costs, net.

(2) We have estimated cash obligations related to our pension and other postretirement benefit programs for five years, as it is not practicable to estimate thereafter. The pension and other 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 $466.9 million. A portion of the costs incurred to purchase this energy is recoverable through rates authorized by the MPSC, totaling approximately $388.4 million.

(4) We have entered into various purchase commitments, largely purchased power, electric transmission, coal and natural gas supply and natural gas transportation contracts (exclusive of the qualifying facilities liability discussed above). These commitments range from one to 24 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, as further described in Note 3 - Regulatory Matters.

(5) Contractual interest payments include our revolving credit facilities, which have a variable interest rate. We have assumed an average interest rate of 1.35 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 18 - Commitments and Contingencies) and asset retirement obligations (AROs) (see Note 6 - Asset Retirement Obligations) as the amount and timing of cash payments may be uncertain.

CRITICAL ACCOUNTING ESTIMATES

Management's discussion and analysis of financial condition and results of operations is based on our Consolidated Financial Statements, which have been prepared in accordance with GAAP. The preparation of these Consolidated 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 have identified the policies and related procedures below that contain accounting estimates that involve a significant level of estimation uncertainty and have had or are reasonably likely to have a material impact on our financial condition or results of operations.

Regulatory Assets and Liabilities

Our operations are subject to the provisions of ASC 980, *Regulated Operations* (ASC 980). Our regulatory assets are the probable future revenues associated with certain costs to be recovered from customers through the ratemaking process, including our estimate of amounts recoverable for natural gas and electric supply purchases. Regulatory liabilities are the probable future reductions in revenues associated with amounts to be credited to customers through the ratemaking process. We determine which costs are recoverable by consulting previous rulings by state regulatory authorities in jurisdictions where we operate or other factors that lead us to believe that cost recovery is probable. This accounting treatment is impacted by the uncertainties of our regulatory environment, anticipated future regulatory decisions and their impact. If any part of our operations becomes no longer subject to the provisions of ASC 980, or facts and circumstances lead us to conclude that a recorded regulatory asset is no longer probable of recovery, we would record a charge to earnings, which could be material. In addition, we would need to determine if there was any impairment to the carrying costs of the associated plant and inventory assets.

While we believe that our assumptions regarding future regulatory actions are reasonable, different assumptions could materially affect our results. See Note 4 - Regulatory Assets and Liabilities, to the Consolidated Financial Statements for further discussion.

Pension and Postretirement Benefit Plans

We sponsor and/or contribute to pension, postretirement health care and life insurance benefits for eligible employees. Our reported costs of providing pension and other postretirement benefits, as described in Note 14 - Employee Benefit Plans, to the Consolidated Financial Statements, are dependent upon numerous factors including the provisions of the plans, changing employee demographics, rate of return on plan assets and other economic conditions, and various actuarial calculations, assumptions, and accounting mechanisms. As a result of these factors, significant portions of pension and other postretirement benefit costs recorded in any period do not reflect (and are generally greater than) the actual benefits provided to plan participants. Due to the complexity of these calculations, the long-term nature of the obligations, and the importance of the assumptions utilized, the determination of these costs is considered a critical accounting estimate.

Assumptions

Key actuarial assumptions utilized in determining these costs include:

- Discount rates used in determining the future benefit obligations;
- Expected long-term rate of return on plan assets; and
- Mortality assumptions.

We review these assumptions on an annual basis and adjust them as necessary. The assumptions are based upon market interest rates, past experience and management's best estimate of future economic conditions.

We set the discount rate using a yield curve analysis, which projects benefit cash flows into the future and then discounts those cash flows to the measurement date using a yield curve. This is done by constructing a hypothetical bond portfolio whose cash flow from coupons and maturities matches the year-by-year projected benefit cash flow from our plans. Based on this analysis as of December 31, 2021, our discount rate on the NorthWestern Corporation pension plan is 2.65 percent and on the NorthWestern Energy pension plan is 2.75 percent.

In determining the expected long-term rate of return on plan assets, we review historical returns, the future expectations for returns for each asset class weighted by the target asset allocation of the pension and postretirement portfolios, and long-term inflation assumptions. Our expected long-term rate of return on assets assumptions are 3.01 percent and 4.17 percent on the NorthWestern Corporation and NorthWestern Energy pension plan, respectively, for 2022.

Cost Sensitivity

The following table reflects the sensitivity of pension costs to changes in certain actuarial assumptions (in thousands):

Actuarial Assumption (1)	Change in Assumption	Impact on Pension Cost	Impact on Projected Benefit Obligation
Discount rate increase	0.25 %	$ (2,232)	$ (23,069)
Discount rate decrease	(0.25)%	2,415	24,377
Rate of return on plan assets increase	0.25 %	(1,670)	N/A
Rate of return on plan assets decrease	(0.25)%	1,670	N/A

(1) Reflects sensitivity to the period pension cost only and excludes the $11.3 million settlement charge during 2021, which was associated with the partial pension annuitization described in Note 14 - Employee Benefit Plans.

Accounting Treatment

We recognize the funded status of each plan as an asset or liability in the Consolidated Balance Sheets. Differences between actuarial assumptions and actual plan results are deferred and are recognized into earnings only when the accumulated differences exceed 10 percent of the greater of the projected benefit obligation or the market-related value of plan assets, which reduces the volatility of reported pension costs. If necessary, the excess is amortized over the average remaining service period of active employees.

Due to the various regulatory treatments of the plans, our Consolidated Financial Statements reflect the effects of the different rate making principles followed by the jurisdictions regulating us. Pension costs in Montana and other postretirement benefit costs in South Dakota are included in rates on a pay as you go basis for regulatory purposes. Pension costs in South Dakota and other postretirement benefit costs in Montana are included in rates on an accrual basis for regulatory purposes. Regulatory assets have been recognized for the obligations that will be included in future cost of service.

Income Taxes

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. Deferred income tax assets and liabilities represent the future effects on income taxes from temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to reverse. The probability of realizing deferred tax assets is based on forecasts of future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. We establish a valuation allowance when it is more likely than not that all, or a portion of, a deferred tax asset will not be realized. Exposures exist related to various tax filing positions, which may require an extended period of time to resolve and may result in income tax adjustments by taxing authorities. We have reduced deferred tax assets or established liabilities based on our best estimate of future probable adjustments related to these exposures. On a quarterly basis, we evaluate exposures in light of any additional information and make adjustments as necessary to reflect the best estimate of the future outcomes. We believe our deferred tax assets and established liabilities are appropriate for estimated exposures; however, actual results may differ significantly from these estimates.

The interpretation of tax laws involves uncertainty. Ultimate resolution of income tax matters may result in favorable or unfavorable impacts to net income and cash flows and adjustments to tax-related assets and liabilities could be material. The uncertainty and judgment involved in the determination and filing of income taxes is accounted for by prescribing a minimum recognition threshold that a tax position is required to meet before being recognized in the Consolidated Financial Statements. We recognize tax positions that meet the more-likely-than-not threshold as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. We have unrecognized tax benefits of approximately $32.0 million as of December 31, 2021. The resolution of tax matters in a particular future period could have a material impact on our provision for income taxes, results of operations and our cash flows. See Note 12 - Income Taxes to the Consolidated Financial Statements for further discussion.

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 $466.9 million through June 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $388.4 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 each reporting period, we compare our assumptions to actual results and make adjustments as necessary for that period.

One of the contracts contains variable pricing terms, which exposes us to price escalation risks. The estimated annual escalation rate for this contract is a key assumption and is based on a combination of historical actual results and market data available for future projections. In recording the electric QF liability, we estimated an annual escalation rate of 3 percent over the remaining term of the contract (through June 2024). The actual escalation rate changes annually, which could significantly impact the liability and our results of operations. See Note 18 - Commitments and Contingencies to the Consolidated Financial Statements for further discussion.

NEW ACCOUNTING STANDARDS

See Note 2 - Significant Accounting Policies, to the Consolidated Financial Statements, included in Item 8 herein for a discussion of new accounting standards.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Interest Rate Risk

Interest rate risks include exposure to adverse interest rate movements for outstanding variable rate debt and for future anticipated financings. We manage our interest rate risk by issuing fixed-rate long-term debt with varying maturities, refinancing certain debt and, at times, hedging the interest rate on anticipated borrowings. All of our debt has fixed interest rates, with the exception of our revolving credit facilities. The $425 million revolving credit facility bears interest at rates equal to the Eurodollar rate, plus a margin of 112.5 to 175.0 basis points, or a base rate, plus a margin of 12.5 to 75.0 basis points. In addition, we have a $25 million revolving credit facility, to provide swingline borrowing capability. The $25 million revolving credit facility bears interest at the lower of prime plus a credit spread of 0.13 percent, or available rates tied to the Eurodollar rate plus a credit spread of 0.65 percent. As of December 31, 2021, we had approximately $373 million in borrowings under our revolving credit facilities. A 1.0 percent increase in interest rates would increase our annual interest expense by approximately $3.7 million.

Commodity Price Risk

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

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

Counterparty Credit Risk

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The consolidated financial information, including the reports of independent registered public accounting firm and the quarterly financial information, required by this Item 8 is set forth on pages F-1 to F-46 of this Annual Report on Form 10-K and is hereby incorporated into this Item 8 by reference.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. 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 December 31, 2021, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

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

Management's Annual Report on Internal Control over Financial Reporting

The management of NorthWestern is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control system was designed to provide reasonable assurance to our management and Board regarding the preparation and fair presentation of published financial statements.

All internal controls over financial reporting, no matter how well designed, have inherent limitations, including the possibility of human error and the circumvention or overriding of controls. Therefore, even effective internal control over financial reporting can provide only reasonable assurance with respect to financial statement preparation and presentation. Further, because of changes in conditions, the effectiveness of internal control over financial reporting may vary over time.

Our management, including our chief executive officer and chief financial officer, assessed the effectiveness of our internal control over financial reporting as of December 31, 2021. In making its assessment of internal control over financial reporting, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control—Integrated Framework (2013). Based on our evaluation, management concluded that, as of December 31, 2021, our internal control over financial reporting was effective based on those criteria.

Our independent registered public accounting firm has issued an attestation report on our internal control over financial reporting. Their report appears on page F-2.

ITEM 9B. OTHER INFORMATION

As previously reported, on April 22, 2021 at the 2021 Annual Meeting of Stockholders, the stockholders approved the NorthWestern Corporation Amended and Restated Equity Compensation Plan (the Plan), including the issuance of an additional 700,000 shares of common stock. The Plan permits a committee of the Board to grant to designated officers, employees and non-employee directors of NorthWestern and its affiliates incentive awards in the form of performance units, restricted shares, restricted share units, unrestricted shares, deferred share units, options, share appreciation rights and other awards including the payment of stock in lieu of cash under our other incentive or bonus programs or otherwise and payment of cash based on attainment of performance goals. A more detailed summary of the material features of the Plan is set forth in our proxy statement for the 2021 Annual Meeting of Stockholders filed with the Securities and Exchange Commission on March 5, 2021. A copy of the Plan is included as an Appendix to such proxy statement.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item with respect to directors and corporate governance will be set forth in NorthWestern Corporation's Proxy Statement for its 2022 Annual Meeting of Shareholders, which is incorporated by reference. Information with respect to our Executive Officers is included under "Information about our Executive Officers" in Item 1 of this report.

ITEM 11. EXECUTIVE COMPENSATION

Information required by this item will be set forth in NorthWestern Corporation's Proxy Statement for its 2022 Annual Meeting of Shareholders, which is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by this item will be set forth in NorthWestern Corporation's Proxy Statement for its 2022 Annual Meeting of Shareholders, which is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information concerning relationships and related transactions of the directors and officers of NorthWestern Corporation and director independence will be set forth in NorthWestern Corporation's Proxy Statement for its 2022 Annual Meeting of Shareholders, which is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information concerning fees paid to the principal accountant, Deloitte & Touche LLP (PCAOB ID No. 34), for each of the last two years will be set forth in NorthWestern Corporation's Proxy Statement for its 2022 Annual Meeting of Shareholders, which is incorporated herein by reference.

ITEM 15. EXHIBIT AND FINANCIAL STATEMENT SCHEDULES

The following documents are filed as part of this report:

(1) Consolidated Financial Statements.

The following items are included in Part II, Item 8 of this annual report on Form 10-K:

CONSOLIDATED FINANCIAL STATEMENTS:

All schedules are omitted because they are not applicable or the required information is shown in the Consolidated Financial Statements or the Notes thereto.

(2) Exhibits.

The exhibits listed below are hereby filed with the SEC, as part of this Annual Report on Form 10-K. Certain of the following exhibits have been previously filed with the SEC pursuant to the requirements of the Securities Act of 1933 or the Securities Exchange Act of 1934. Such exhibits are identified by the parenthetical references following the listing of each such exhibit and are incorporated by reference. We will furnish a copy of any exhibit upon request, but a reasonable fee may be charged to cover our expenses in furnishing such exhibit.

Exhibit Number	Description of Document
2.1(a)	Second Amended and Restated Plan of Reorganization of NorthWestern Corporation (incorporated by reference to Exhibit 2.1 of NorthWestern Corporation's Current Report on Form 8-K, dated October 20, 2004, Commission File No. 1-10499).
2.1(b)	Order Confirming the Second Amended and Restated Plan of Reorganization of NorthWestern Corporation (incorporated by reference to Exhibit 2.2 of NorthWestern Corporation's Current Report on Form 8-K, dated October 20, 2004, Commission File No. 1-10499).
3.1(a)	Amended and Restated Certificate of Incorporation of NorthWestern Corporation, dated May 3, 2016 (incorporated by reference to Exhibit 3.1 of NorthWestern Corporation's Current Report on Form 8-K, dated May 18, 2016, Commission File No. 1-10499).
3.2(a)	Amended and Restated Bylaws of NorthWestern Corporation, dated May 12, 2016 (incorporated by reference to Exhibit 3.2 of NorthWestern Corporation's Current Report on Form 8-K, dated May 18, 2016, Commission File No. 1-10499).
4.1(a)	First Mortgage and Deed of Trust, dated as of October 1, 1945, by The Montana Power Company in favor of Guaranty Trust Company of New York and Arthur E. Burke, as trustees (incorporated by reference to Exhibit 7(e) of The Montana Power Company's Registration Statement, Commission File No. 002-05927).
4.1(b)	Eighteenth Supplemental Indenture to the Mortgage and Deed of Trust, dated as of August 5, 1994 (incorporated by reference to Exhibit 99(b) of The Montana Power Company's Registration Statement on Form S-3, dated December 5, 1994, Commission File No. 033-56739).
4.1(c)	Twenty-Eighth Supplemental Indenture, dated as of October 1, 2009, by and between NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, Commission File No. 1-10499).
4.1(d)	Twenty-Ninth Supplemental Indenture, dated as of May 1, 2010, among NorthWestern Corporation and The Bank of New York Mellon and Ming Ryan, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, Commission File No. 1-10499).
4.1(e)	Thirtieth Supplemental Indenture, dated as of August 1, 2012, between NorthWestern Corporation and The Bank of New York Mellon and Philip L. Watson, as trustees under the Mortgage and Deed of Trust dated as of October 1, 1945 (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated August 10, 2012, Commission File No. 1-10499).
4.1(f)	Thirty-First Supplemental Indenture, dated as of December 1, 2013, among NorthWestern Corporation and The Bank of New York Mellon and Phillip L. Watson, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated December 19, 2013, Commission File No. 1-10499).
4.1(g)	Thirty-Second Supplemental Indenture, dated as of November 1, 2014, among NorthWestern Corporation and The Bank of New York Mellon and Phillip L. Watson, as trustees (incorporated by reference to Exhibit 4.4(n) of the Company's Report on Form 10-K for the year ended December 31, 2014, Commission File No. 1-10499).
4.1(h)	Thirty-Third Supplemental Indenture, dated as of November 1, 2014, among NorthWestern Corporation and The Bank of New York Mellon and Phillip L. Watson, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated November 14, 2014, Commission File No. 1-10499).
4.1(i)	Thirty-Fourth Supplemental Indenture, dated as of January 1, 2015, among NorthWestern Corporation and The Bank of New York Mellon and Phillip L. Watson, as trustees (incorporated by reference to Exhibit 4.4(p) of the Company's Report on Form 10-K for the year ended December 31, 2014, Commission File No. 1-10499).
4.1(j)	Thirty-Fifth Supplemental Indenture, dated as of June 1, 2015, among NorthWestern Corporation and The Bank of New York Mellon and Beata Harvin, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated June 29, 2015, Commission File No. 1-10499).

4.1(k)	Thirty-Seventh Supplemental Indenture, dated as of November 1, 2017, among NorthWestern Corporation and The Bank of New York Mellon and Beata Harvin, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated November 8, 2017, Commission File No. 1-10499).
4.1(l)	Thirty-Eighth Supplemental Indenture, dated as of June 1, 2019, among NorthWestern Corporation and The Bank of New York Mellon and Beata Harvin, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated July 2, 2019, Commission File No. 1-10499).
4.1(m)	Thirty-Ninth Supplemental Indenture, dated as of September 1, 2019, among NorthWestern Corporation and The Bank of New York Mellon and Beata Harvin, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated September 20, 2019, Commission File No. 1-10499).
4.1(n)	Fortieth Supplemental Indenture, dated as of April 1, 2020, among NorthWestern Corporation and The Bank of New York Mellon and Beata Harvin, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated May 15, 2020, Commission File No. 1-10499).
4.2(a)	General Mortgage Indenture and Deed of Trust, dated as of August 1, 1993, from NorthWestern Corporation to The Chase Manhattan Bank (National Association), as Trustee (incorporated by reference to Exhibit 4(a) of NorthWestern Corporation's Current Report on Form 8-K, dated August 16, 1993, Commission File No. 1-10499).
4.2(b)	Supplemental Indenture, dated as of November 1, 2004, by and between NorthWestern Corporation (formerly known as Northwestern Public Service Company) and JPMorgan Chase Bank (successor by merger to The Chase Manhattan Bank (National Association)), as Trustee under the General Mortgage Indenture and Deed of Trust dated as of August 1, 1993 (incorporated by reference to Exhibit 4.5 of NorthWestern Corporation's Current Report on Form 8-K, dated November 1, 2004, Commission File No. 1-10499).
4.2(c)	Ninth Supplemental Indenture, dated as of May 1, 2010, by and between NorthWestern Corporation and The Bank of New York Mellon, as trustee under the General Mortgage Indenture and Deed of Trust dated as of August 1, 1993 (incorporated by reference to Exhibit 4.2 of NorthWestern Corporation’s Current Report on Form 10-Q for the quarter ended June 30, 2010, Commission File No. 1-10499).
4.2(d)	Tenth Supplemental Indenture, dated as of August 1, 2012, between NorthWestern Corporation and The Bank of New York Mellon, as trustees under the General Mortgage Indenture and Deed of Trust dated as of August 1, 1993 (incorporated by reference to Exhibit 4.2 of NorthWestern Corporation's Current Report on Form 8-K, dated August 10, 2012, Commission File No. 1-10499).
4.2(e)	Eleventh Supplemental Indenture, dated as of December 1, 2013, among NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.2 of NorthWestern Corporation’s Current Report on Form 8-K, dated December 19, 2013, Commission File No. 1-10499).
4.2(f)	Twelfth Supplemental Indenture, dated as of December 1, 2014, among NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation’s Current Report on Form 8-K, dated December 19, 2014, Commission File No. 1-10499).
4.2(g)	Thirteenth Supplemental Indenture, dated as of September 1, 2015, among NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation’s Current Report on Form 8-K, dated September 29, 2015, Commission File No. 1-10499).
4.2(h)	Fourteenth Supplemental Indenture, dated as of June 1, 2016, between the NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated June 21, 2016, Commission File No. 1-10499).
4.2(i)	Fifteenth Supplemental Indenture, dated as of September 1, 2016, among NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation’s Current Report on Form 8-K, dated October 6, 2016, Commission File No. 1-10499).
4.2(j)	Sixteenth Supplemental Indenture, dated as of April 1, 2020, among NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.2 of NorthWestern Corporation's Current Report on Form 8-K, dated May 15, 2020, Commission File No. 1-10499).
4.3(a)	Indenture, dated as of August 1, 2016, between City of Forsyth, Rosebud County, Montana and U.S. Bank National Association, as trustee agent (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated August 16, 2016, Commission File No. 1-10499).
4.3(b)	Loan Agreement, dated as of August 1, 2016, between NorthWestern Corporation and the City of Forsyth, Montana, related to the issuance of City of Forsyth Pollution Control Revenue Bonds Series 2016 (incorporated by reference to Exhibit 4.2 of the Company's Report on Form 8-K, dated August 16, 2016, Commission File No. 1-10499).
4.3(c)	Bond Delivery Agreement, dated as of August 1, 2016, between NorthWestern Corporation and U.S. Bank National Association, as trustee agent (incorporated by reference to Exhibit 4.3 of NorthWestern Corporation's Current Report on Form 8-K, dated August 16, 2016, Commission File No. 1-10499).

4.3(d)	Thirty-Sixth Supplemental Indenture, dated as of August 1, 2016, among NorthWestern Corporation and The Bank of New York Mellon and Beata Harvin, as trustees (incorporated by reference to Exhibit 4.4 of NorthWestern Corporation's Current Report on Form 8-K, dated August 16, 2016, Commission File No. 1-10499).
4.3(e)	Forty-First Supplemental Indenture, dated as of March 1, 2021, among NorthWestern Corporation and The Bank of New York Mellon and Beata Harvin, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated March 26, 2021, Commission File No. 1-10499).
4.5*	Description of Securities
10.1(a) †	NorthWestern Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, as amended April 21, 2010 (incorporated by reference to Exhibit 10.3 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, Commission File No. 1-10499).
10.1(b) †	NorthWestern Corporation 2009 Officers Deferred Compensation Plan, as amended April 21, 2010 (incorporated by reference to Exhibit 10.4 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, Commission File No. 1-10499).
10.1(c) †	Form of NorthWestern Corporation Executive Retirement/Retention Program Restricted Share Unit Award Agreement (incorporated by reference to Exhibit 99.2 of NorthWestern Corporation's Current Report on Form 8-K, dated December 5, 2011, Commission File No. 1-10499).
10.1(d) †	Form of NorthWestern Corporation Executive Retirement/Retention Program Restricted Share Unit Award Agreement (incorporated by reference to Exhibit 99.2 of NorthWestern Corporation's Current Report on Form 8-K, dated December 12, 2012, Commission File No. 1-10499).
10.1(e) †	Form of NorthWestern Corporation Executive Retirement/Retention Program Restricted Share Unit Award Agreement (incorporated by reference to Exhibit 99.2 of NorthWestern Corporation's Current Report on Form 8-K, dated December 10, 2013, Commission File No. 1-10499).
10.1(f) †	Form of NorthWestern Corporation Performance Unit Award Agreement (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Current Report on Form 8-K, dated February 18, 2014, Commission File No. 1-10499).
10.1(g) †	NorthWestern Corporation Amended and Restated Equity Compensation Plan, as amended effective July 1, 2014 (incorporated by reference to Appendix A to NorthWestern Corporation's Proxy Statement for the 2014 Annual Meeting of Shareholders filed on March 7, 2014, Commission File No. 1-10499).
10.1(h) †	Form of NorthWestern Corporation Executive Retirement/Retention Program Restricted Share Unit Award Agreement (incorporated by reference to Exhibit 99.2 of NorthWestern Corporation's Current Report on Form 8-K, dated December 22, 2014, Commission File No. 1-10499).
10.1(i) †	NorthWestern Corporation Key Employee Severance Plan 2016 (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated October 25, 2016, Commission File No. 1-10499).
10.1(j) †	Form of NorthWestern Corporation Executive Retirement/Retention Program Restricted Share Unit Award Agreement (incorporated by reference to Exhibit 99.2 of NorthWestern Corporation's Current Report on Form 8-K, dated December 13, 2016, Commission File No. 1-10499).
10.1(k) †	Form of NorthWestern Corporation Performance Unit Award Agreement (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Current Report on Form 8-K, dated February 23, 2017, Commission File No. 1-10499).
10.1(l) †	Form of NorthWestern Corporation Performance Unit Award Agreement (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Current Report on Form 8-K, dated February 16, 2018, Commission File No. 1-10499).
10.1(m) †	Form of NorthWestern Corporation Executive Retirement/Retention Program Restricted Share Unit Award Agreement (incorporated by reference to Exhibit 99.2 of NorthWestern Corporation's Current Report on Form 8-K, dated December 19, 2018, Commission File No. 1-10499).
10.1(n) †	Form of NorthWestern Corporation Performance Unit Award Agreement (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Current Report on Form 8-K, dated February 15, 2019, Commission File No. 1-10499).
10.1(o) †	NorthWestern Energy 2020 Annual Incentive Plan (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Current Report on Form 8-K, dated December 23, 2019, Commission File No. 1-10499).
10.1(p) †	Form of NorthWestern Corporation Executive Retirement/Retention Program Restricted Share Unit Award Agreement (incorporated by reference to Exhibit 99.2 of NorthWestern Corporation's Current Report on Form 8-K, dated December 23, 2019, Commission File No. 1-10499).
10.1(q) †	NorthWestern Energy 2021 Annual Incentive Plan (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Current Report on Form 8-K, dated December 22, 2020, Commission File No. 1-10499).

10.1(r) †	Form of NorthWestern Corporation Executive Retirement/Retention Program Restricted Share Unit Award Agreement (incorporated by reference to Exhibit 99.2 of NorthWestern Corporation's Current Report on Form 8-K, dated December 22, 2020, Commission File No. 1-10499).
10.1(s) †	Form of NorthWestern Corporation Performance Unit Award Agreement (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Current Report on Form 8-K, dated February 11, 2021, Commission File No. 1-10499).
10.1(t) †	NorthWestern Corporation Amended and Restated Equity Compensation Plan, as amended effective May 1, 2021 (incorporated by reference to Appendix A to NorthWestern Corporation's Proxy Statement for the 2014 Annual Meeting of Shareholders filed on March 5, 2021, Commission File No. 1-10499).
10.1(u) †	NorthWestern Energy 2022 Annual Incentive Plan (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Current Report on Form 8-K, dated December 22, 2021, Commission File No. 1-10499).
10.1(v) †	Form of NorthWestern Corporation Executive Retirement/Retention Program Restricted Share Unit Award Agreement (incorporated by reference to Exhibit 99.2 of NorthWestern Corporation's Current Report on Form 8-K, dated December 22, 2021, Commission File No. 1-10499).
10.2(a)	Commercial Paper Dealer Agreement between NorthWestern Corporation and Merrill Lynch, Pierce, Fenner & Smith Incorporated, dated as of February 3, 2011 (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated February 8, 2011, Commission File No. 1-10499).
10.2(b)	Bond Purchase Agreement, dated as of October 31, 2017, between NorthWestern Corporation and initial purchasers (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Current Report on form 10-Q, dated November 2, 2017, Commission File No. 1-10499).
10.2(c)	Credit Agreement, dated September 2, 2020, among NorthWestern Corporation, as borrower; the several banks and other financial institutions or entities from time to time parties to the agreement, as lenders; BofA Securities, Inc., Credit Suisse Securities (USA) LLC, and U.S. Bank National Association as joint lead arrangers; Credit Suisse Securities (USA) LLC, and U.S. Bank National Association as co-syndication agents; Keybank National Association as documentation agent; and Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated September 4, 2020, Commission File No. 1-10499).
10.3(a)	Equity Distribution Agreement, dated April 23, 2021, between NorthWestern Corporation and J.P. Morgan Securities LLC, BofA Securities, Inc., CIBC World Markets Corp. and Credit Suisse Securities (USA) LLC, as sales agents and forward sellers; and JPMorgan Chase Bank, National Association, Bank of America N.A, Canadian Imperial Bank of Commerce and Credit Suisse Capital LLC, as forward purchasers. (incorporated by reference to Exhibit 1.1 of NorthWestern Corporation's Current Report on Form 8-K, dated April 23, 2021, Commission File No. 1-10499).
10.3(b)	Form of Master Forward Sale Confirmation (incorporated by reference to Exhibit 1.2 of Northwestern Corporation's Current Report on Form 8-K, dated April 23, 2021, Commission File No. 1-10499)
10.3(c)	Forward Sale Agreement, dated November 16, 2021, between NorthWestern Corporation and Bank of America, N.A., as forward purchaser (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated November 15, 2021, Commission File No. 1-10499).
10.3(d)	Additional Forward Sale Agreement, dated November 17, 2021, between NorthWestern Corporation and Bank of America, N.A., as forward purchaser (incorporated by reference to Exhibit 10.2 of NorthWestern Corporation's Current Report on Form 8-K, dated November 15, 2021, Commission File No. 1-10499).
10.4(a)	Engineering, Procurement, and Construction Contract, dated April 19, 2021, between Northwestern Energy and Burns & McDonnell Engineering Company, Inc (incorporated by reference to Exhibit 10.3 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2021, Commission File No. 1-10499).
10.4(b)	Procurement Contract, dated April 19, 2021, between Northwestern Energy and Caterpillar Power Generation Systems, LLC (incorporated by reference to Exhibit 10.4 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2021, Commission File No. 1-10499).
21*	Subsidiaries of NorthWestern Corporation.
23*	Consent of Independent Registered Public Accounting Firm
24*	Power of Attorney (included on the signature page of this Annual Report on Form 10-K)
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes Oxley Act of 2002
32.1*	Certification of Robert C. Rowe pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Crystal Lail pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
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.
101.SCH*	Inline XBRL Taxonomy Extension Schema Document

101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	Inline XBRL Taxonomy Label Linkbase Document
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104 Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)	

† Management contract or compensatory plan or arrangement.
* Filed herewith.

All schedules for which provision is made in the applicable accounting regulations of the SEC are not required under the related instructions or are not applicable, and, therefore, have been omitted.

ITEM 16. FORM 10-K SUMMARY

Not applicable.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Annual Report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized.

NORTHWESTERN CORPORATION

February 11, 2022	By:	/s/ ROBERT C. ROWE
		Robert C. Rowe
		Chief Executive Officer

POWER OF ATTORNEY

We, the undersigned directors and/or officers of NorthWestern Corporation, hereby severally constitute and appoint Robert C. Rowe and Crystal D. Lail, and each of them with full power to act alone, our true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution and revocation, for each of us and in our name, place, and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file or cause to be filed the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, and hereby grant unto such attorneys-in-fact and agents, and each of them, the full power and authority to do each and every act and thing requisite and necessary to be done in and about the foregoing, as fully to all intents and purposes as each of us might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, or their respective substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual Report on Form 10-K has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ DANA J. DYKHOUSE Dana J. Dykhouse	Chairman of the Board	February 11, 2022
/s/ ROBERT C. ROWE Robert C. Rowe	Chief Executive Officer and Director (Principal Executive Officer)	February 11, 2022
/s/ CRYSTAL D. LAIL Crystal D. Lail	Vice President and Chief Financial Officer (Principal Financial Officer)	February 11, 2022
/s/ JEFFREY B. BERZINA Jeffrey B. Berzina	Controller (Principal Accounting Officer)	February 11, 2022
/s/ ANTHONY T. CLARK Anthony T. Clark	Director	February 11, 2022
/s/ JAN R. HORSFALL Jan R. Horsfall	Director	February 11, 2022
/s/ BRITT E. IDE Britt E. Ide	Director	February 11, 2022
/s/ LINDA G. SULLIVAN Linda G. Sullivan	Director	February 11, 2022
/s/ MAHVASH YAZDI Mahvash Yazdi	Director	February 11, 2022
/s/ JEFFREY W. YINGLING Jeffrey W. Yingling	Director	February 11, 2022

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of NorthWestern Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of NorthWestern Corporation and subsidiaries (the "Company") as of December 31, 2021 and 2020, the related consolidated statements of income, comprehensive income, cash flows and common shareholders' equity, for each of the three years in the period ended December 31, 2021, and the related notes (collectively, referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 10, 2022, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Matters - Impact of Rate Regulation on the Financial Statements-Refer to Notes 2, 3, and 4 to the financial statements

Critical Audit Matter Description

The Company is subject to rate regulation by federal and state utility regulatory agencies (collectively, the “Commissions”), which have jurisdiction over the Company’s electric and natural gas distribution rates in Montana, South Dakota and Nebraska. Management has determined regulated accounting is appropriate provided that (i) rates are established by or subject to approval by independent, third-party regulators, (ii) rates are designed to recover the specific enterprise's cost of service, and (iii) in view of demand for service, it is reasonable to assume that rates are set at levels that will recover costs and can be charged to and collected from customers. Accounting for the economics of rate regulation affects multiple financial statement line items and disclosures, including property, plant, and equipment; regulatory assets and liabilities; operating revenues and expenses; depreciation expense; income taxes; and multiple disclosures in the notes to the financial statements.

Rates are determined and approved in regulatory proceedings based on an analysis of the Company’s costs to provide utility service and a return on, and recovery of, the Company’s capital investment in its utility operations. The economic effects of regulation can result in regulated companies recording costs that have been, or are deemed probable to be, allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this occurs, costs are deferred as regulatory assets and recorded as expenses in the periods when those same amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers (regulatory liabilities). The Commissions' regulation of rates is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital. While the Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that the Commissions will not approve: (1) full recovery of the costs of providing utility service or (2) full recovery of all amounts invested in the utility business and a reasonable return on that investment.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about affected account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, (2) a disallowance of capital expenditures or operating costs that management believes were prudently incurred, and (3) refunds to be provided to customers. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the Commissions, auditing these judgments requires specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commissions included the following, among others:

- We tested the effectiveness of management's controls over the evaluation of the likelihood of (1) the recovery in future rates of costs incurred as regulatory assets, and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We also tested the effectiveness of management's controls over the recognition of amounts as property, plant, and equipment; regulatory assets or liabilities; and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.

- We evaluated the Company's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.

- We read relevant regulatory orders issued by the Commissions, regulatory statutes, interpretations, procedural memorandums, filings made by intervenors, filings made by the Company, and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions' treatment of similar costs under similar circumstances. We evaluated the external information and compared to management's recorded regulatory asset and liability balances for completeness.

- We evaluated regulatory filings and testimony for any evidence that intervenors are challenging full recovery of the cost of any capital projects or operating costs. If full recovery of project costs is being challenged by intervenors, we evaluated management's assessment of the probability of a disallowance.

- We assessed management's conclusion regarding probability of recovery for regulatory assets or refund or future reduction in rates for regulatory liabilities not yet addressed in a regulatory order to assess management's assertion that amounts are probable of recovery or a future reduction in rates.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota

February 10, 2022

We have served as the Company's auditor since 2002.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of NorthWestern Corporation

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of NorthWestern Corporation and subsidiaries (the "Company") as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2021, of the Company and our report dated February 10, 2022, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying "Management's Annual Report on Internal Control over Financial Reporting." Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota

February 10, 2022

NORTHWESTERN CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

(in thousands, except per share amounts)

	Year Ended December 31,		
	2021	**2020**	**2019**
Revenues			
Electric	$ 1,052,182	$ 940,815	$ 981,178
Gas	320,134	257,855	276,732
Total Revenues	1,372,316	1,198,670	1,257,910
Operating Expenses			
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	425,548	306,190	318,020
Operating and maintenance	208,303	202,991	209,052
Administrative and general	101,873	94,124	109,177
Property and other taxes	173,444	179,517	171,888
Depreciation and depletion	187,467	179,644	172,923
Total Operating Expenses	1,096,635	962,466	981,060
Operating Income	275,681	236,204	276,850
Interest Expense, net	(93,674)	(96,812)	(95,068)
Other Income, net	8,252	4,853	413
Income Before Income Taxes	190,259	144,245	182,195
Income Tax (Expense) Benefit	(3,419)	10,970	19,925
Net Income	$ 186,840	$ 155,215	$ 202,120
Average Common Shares Outstanding	51,709	50,559	50,429
Basic Earnings per Average Common Share	$ 3.61	$ 3.07	$ 4.01
Diluted Earnings per Average Common Share	$ 3.60	$ 3.06	$ 3.98

See Notes to Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in thousands)

	Year Ended December 31,		
	2021	**2020**	**2019**
Net Income	$ 186,840	$ 155,215	$ 202,120
Other comprehensive (loss) income, net of tax:			
Reclassification of net losses on derivative instruments	452	452	452
Postretirement medical liability adjustment	(436)	1,840	(131)
Foreign currency translation	(57)	87	(35)
Total Other Comprehensive (Loss) Income	(41)	2,379	286
Comprehensive Income	$ 186,799	$ 157,594	$ 202,406

See Notes to Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONSOLIDATED BALANCE SHEETS

(in thousands, except per share amounts)

	Year Ended December 31,	
	2021	**2020**
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 2,820	$ 5,811
Restricted cash	15,942	11,285
Accounts receivable, net	198,671	168,229
Inventories	80,614	61,010
Regulatory assets	115,541	44,973
Prepaid expenses and other	24,207	17,372
Total current assets	**437,795**	**308,680**
Property, plant, and equipment, net	5,247,232	4,952,935
Goodwill	357,586	357,586
Regulatory assets	690,686	701,444
Other noncurrent assets	47,144	68,804
Total Assets	**$ 6,780,443**	**$ 6,389,449**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current maturities of finance leases	$ 2,875	$ 2,668
Short-term borrowings	—	100,000
Accounts payable	115,237	100,388
Accrued expenses	233,351	207,514
Regulatory liabilities	28,179	55,853
Total current liabilities	**379,642**	**466,423**
Long-term finance leases	11,897	14,771
Long-term debt	2,541,478	2,315,261
Deferred income taxes	499,634	471,777
Noncurrent regulatory liabilities	638,760	631,419
Other noncurrent liabilities	369,319	410,703
Total Liabilities	**4,440,730**	**4,310,354**
Commitments and Contingencies (Note 18)		
Shareholders' Equity:		
Common stock, par value $0.01; authorized 200,000,000 shares; issued and outstanding 57,606,252 and 54,060,608, respectively; Preferred stock, par value $0.01; authorized 50,000,000 shares; none issued	576	541
Treasury stock at cost	(98,248)	(98,075)
Paid-in capital	1,716,227	1,513,787
Retained earnings	728,468	670,111
Accumulated other comprehensive loss	(7,310)	(7,269)
Total Shareholders' Equity	**2,339,713**	**2,079,095**
Total Liabilities and Shareholders' Equity	**$ 6,780,443**	**$ 6,389,449**

See Notes to Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31,		
	2021	**2020**	**2019**
OPERATING ACTIVITIES:			
Net Income	$ 186,840	$ 155,215	$ 202,120
Items not affecting cash:			
Depreciation and depletion	187,467	179,644	172,923
Amortization of debt issuance costs, discount and deferred hedge gain	5,250	4,911	4,648
Stock-based compensation costs	5,350	4,149	8,007
Equity portion of allowance for funds used during construction	(11,092)	(6,895)	(5,768)
(Gain) loss on disposition of assets	(47)	37	(188)
Deferred income taxes	525	(7,574)	(13,864)
Changes in current assets and liabilities:			
Accounts receivable	(30,442)	(824)	(5,032)
Inventories	(19,604)	(7,085)	(3,110)
Other current assets	(6,835)	(3,477)	(3,140)
Accounts payable	7,494	16,043	(1,821)
Accrued expenses	26,055	5,909	(16,023)
Regulatory assets	(69,616)	14,749	(16,028)
Regulatory liabilities	(27,674)	22,773	(7,796)
Other noncurrent assets	2,313	(5,396)	(22,841)
Other noncurrent liabilities	(36,006)	(20,030)	4,633
Cash Provided by Operating Activities	219,978	352,149	296,720
INVESTING ACTIVITIES:			
Property, plant, and equipment additions	(434,328)	(405,762)	(316,016)
Investment in equity securities	(1,505)	(42)	(135)
Cash Used in Investing Activities	(435,833)	(405,804)	(316,151)
FINANCING ACTIVITIES:			
Dividends on common stock	(128,483)	(120,350)	(115,127)
Proceeds from issuance of common stock, net	196,246	—	—
Issuance of long-term debt	99,915	150,000	150,000
Repayments on long-term debt	(955)	—	—
Line of credit borrowings (repayments), net	151,000	(67,000)	(19,000)
(Repayments) issuances of short-term borrowings	(100,000)	100,000	—
Treasury stock activity	707	(1,391)	1,432
Financing costs	(909)	(2,578)	(1,115)
Cash Provided by Financing Activities	217,521	58,681	16,190
Net Increase (Decrease) in Cash, Cash Equivalents, and Restricted Cash	1,666	5,026	(3,241)
Cash, Cash Equivalents, and Restricted Cash, beginning of period	17,096	12,070	15,311
Cash, Cash Equivalents, and Restricted Cash, end of period	**$ 18,762**	**$ 17,096**	**$ 12,070**

See Notes to Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY

(in thousands, except per share data)

	Number of Common Shares	Number of Treasury Shares	Common Stock	Paid in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Total Shareholders' Equity
Balance at December 31, 2018	**53,889**	**3,566**	**$ 539**	**$1,499,070**	**$ (95,546)**	**$ 548,253**	**$ (9,934)**	**$ 1,942,382**
Net income	—	—	—	—	—	202,120	—	202,120
Foreign currency translation adjustment, net of tax	—	—	—	—	—	—	(35)	(35)
Reclassification of net gains on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	452	452
Postretirement medical liability adjustment, net of tax	—	—	—	—	—	—	(131)	(131)
Stock based compensation	110	25	2	7,964	(1,657)	—	—	6,309
Issuance of shares	—	(44)	—	1,936	1,188	—	—	3,124
Dividends on common stock ($2.30 per share)	—	—	—	—	—	(115,127)	—	(115,127)
Balance at December 31, 2019	**53,999**	**3,547**	**$ 541**	**$1,508,970**	**$ (96,015)**	**$ 635,246**	**$ (9,648)**	**$ 2,039,094**
Net income	—	—	—	—	—	155,215	—	155,215
Foreign currency translation adjustment, net of tax	—	—	—	—	—	—	87	87
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	452	452
Postretirement medical liability adjustment, net of tax	—	—	—	—	—	—	1,840	1,840
Stock based compensation	146	35	—	4,100	(2,741)	—	—	1,359
Issuance of shares	—	(24)	—	717	681	—	—	1,398
Dividends on common stock ($2.40 per share)	—	—	—	—	—	(120,350)	—	(120,350)
Balance at December 31, 2020	**54,145**	**3,558**	**$ 541**	**$1,513,787**	**$ (98,075)**	**$ 670,111**	**$ (7,269)**	**$ 2,079,095**
Net income	—	—	—	—	—	186,840	—	186,840
Foreign currency translation adjustment, net of tax	—	—	—	—	—	—	(57)	(57)
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	452	452
Postretirement medical liability adjustment, net of tax	—	—	—	—	—	—	(436)	(436)
Stock based compensation	93	17	1	5,298	(971)	—	—	4,328
Issuance of shares	3,368	(29)	34	197,142	798	—	—	197,974
Dividends on common stock ($2.48 per share)	—	—	—	—	—	(128,483)	—	(128,483)
Balance at December 31, 2021	**57,606**	**3,546**	**$ 576**	**$1,716,227**	**$ (98,248)**	**$ 728,468**	**$ (7,310)**	**$ 2,339,713**

See Notes to Consolidated Financial Statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(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. We have generated and distributed electricity in South Dakota and distributed natural gas in South Dakota and Nebraska since 1923 and have generated and distributed electricity and distributed natural gas in Montana since 2002.

The Consolidated Financial Statements for the periods included herein have been prepared by NorthWestern Corporation (NorthWestern, we or us), pursuant to the rules and regulations of the SEC. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that may affect the reported amounts of assets, liabilities, revenues and expenses during the reporting period. Actual results could differ from those estimates. The accompanying Consolidated Financial Statements include our accounts together with those of our wholly and majority-owned or controlled subsidiaries. All intercompany balances and transactions have been eliminated from the Consolidated Financial Statements. Events occurring subsequent to December 31, 2021, have been evaluated as to their potential impact to the Consolidated Financial Statements through the date of issuance.

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.

Variable Interest Entities

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

Certain long-term purchase power and tolling contracts may be considered variable interests. We have various long-term purchase power contracts with other utilities and certain QF plants. We identified one QF contract that may constitute a VIE. We entered into a power purchase contract in 1984 with this 35 MW coal-fired QF to purchase substantially all of the facility's capacity and electrical output over a substantial portion of its estimated useful life. We absorb a portion of the facility's variability through annual changes to the price we pay per MWH (energy payment). After making exhaustive efforts, we have been unable to obtain the information from the facility necessary to determine whether the facility is a VIE or whether we are the primary beneficiary of the facility. The contract with the facility contains no provision which legally obligates the facility to release this information. We have accounted for this QF contract as an executory contract. Based on the current contract terms with this QF, our estimated gross contractual payments aggregate to approximately $67.6 million through 2024. For further discussion of our gross QF liability, see Note 18 - Commitments and Contingencies. During the years ended December 31, 2021, 2020 and 2019 purchases from this QF were approximately $26.1 million, $22.2 million, and $23.4 million, respectively.

(2) Significant Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Estimates are used for such items as long-lived asset values and impairment charges, long-lived asset useful lives, tax provisions, uncertain tax position reserves, asset retirement obligations, regulatory assets and liabilities, allowances for uncollectible accounts, our QF liability, environmental liabilities, unbilled revenues and actuarially determined benefit costs and liabilities. We revise the recorded estimates when we receive better information or when we can determine actual amounts. Those revisions can affect operating results.

Revenue Recognition

The Company recognizes revenue as customers obtain control of promised goods and services in an amount that reflects consideration expected in exchange for those goods or services. Generally, the delivery of electricity and natural gas results in the transfer of control to customers at the time the commodity is delivered and the amount of revenue recognized is equal to the amount billed to each customer, including estimated volumes delivered when billings have not yet occurred.

Cash Equivalents

We consider all highly liquid investments with maturities of three months or less at the time of purchase to be cash equivalents.

Restricted Cash

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

Accounts Receivable, Net

Accounts receivable are net of allowances for uncollectible accounts of $2.3 million and $5.6 million at December 31, 2021 and December 31, 2020. Receivables include unbilled revenues of $98.1 million and $80.5 million at December 31, 2021 and December 31, 2020, respectively.

Inventories

Inventories are stated at average cost. Inventory consisted of the following (in thousands):

	December 31,	
	2021	**2020**
Materials and supplies	$ 54,137	$ 44,311
Storage gas and fuel	26,477	16,699
Total Inventories	$ 80,614	$ 61,010

Regulation of Utility Operations

Our regulated operations are subject to the provisions of ASC 980, Regulated Operations. Regulated accounting is appropriate provided that (i) rates are established by or subject to approval by independent, third-party regulators, (ii) rates are designed to recover the specific enterprise's cost of service, and (iii) in view of demand for service, it is reasonable to assume that rates are set at levels that will recover costs and can be charged to and collected from customers.

Our Consolidated Financial Statements reflect the effects of the different rate making principles followed by the jurisdictions regulating us. The economic effects of regulation can result in regulated companies recording costs that have been, or are deemed probable to be, allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this occurs, costs are deferred as regulatory assets and recorded as expenses in the periods when those same amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers (regulatory liabilities).

If we were required to terminate the application of these provisions to our regulated operations, all such deferred amounts would be recognized in the Consolidated Statements of Income at that time. This would result in a charge to earnings and accumulated other comprehensive loss (AOCL), net of applicable income taxes, which could be material. In addition, we would determine any impairment to the carrying costs of deregulated plant and inventory assets.

Derivative Financial Instruments

We account for derivative instruments in accordance with ASC 815, Derivatives and Hedging. All derivatives are recognized in the Consolidated Balance Sheets at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales exception. Additionally, derivatives that qualify and are designated for hedge accounting are classified as either hedges of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair-value hedge) or hedges of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash-flow hedge). For fair-value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash-flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in AOCL and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For other derivative contracts that do not qualify or are not designated for hedge accounting, changes in the fair value of the derivatives are recognized in earnings each period. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing cash flows in the Consolidated Statements of Cash Flows, depending on the underlying nature of the hedged items.

Revenues and expenses on contracts that are designated as normal purchases and normal sales are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but on an accrual basis of accounting. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time, and price is not tied to an unrelated underlying derivative. As part of our regulated electric and gas operations, we enter into contracts to buy and sell energy to meet the requirements of our customers. These contracts include short-term and long-term commitments to purchase and sell energy in the retail and wholesale markets with the intent and ability to deliver or take delivery. If it were determined that a transaction designated as a normal purchase or a normal sale no longer met the exceptions, the fair value of the related contract would be reflected as an asset or liability and immediately recognized through earnings. See Note 8 - Risk Management and Hedging Activities, for further discussion of our derivative activity.

Property, Plant and Equipment

Property, plant and equipment are stated at original cost, including contracted services, direct labor and material, AFUDC, and indirect charges for engineering, supervision and similar overhead items. All expenditures for maintenance and repairs of utility property, plant and equipment are charged to the appropriate maintenance expense accounts. A betterment or replacement of a unit of property is accounted for as an addition and retirement of utility plant. At the time of such a retirement, the accumulated provision for depreciation is charged with the original cost of the property retired and also for the net cost of removal. Also included in plant and equipment are assets under finance lease, which are stated at the present value of minimum lease payments.

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. While cash is not realized currently from such allowance, it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to interest expense, while the equity component is included in other income. This rate averaged 6.6%, 6.7%, and 6.9% for Montana for 2021, 2020, and 2019, respectively. This rate averaged 6.4%, 6.7%, and 6.6% for South Dakota for 2021, 2020, and 2019, respectively. AFUDC capitalized totaled $15.9 million, $9.8 million, and $8.2 million for the years ended December 31, 2021, 2020, and 2019, respectively, for Montana and South Dakota combined.

We record provisions for depreciation at amounts substantially equivalent to calculations made on a straight-line method by applying various rates based on useful lives of the various classes of properties (ranging from 2 to 96 years) determined from engineering studies. As a percentage of the depreciable utility plant at the beginning of the year, our provision for depreciation of utility plant was approximately 2.8% for 2021, 2020, and 2019.

Depreciation rates include a provision for our share of the estimated costs to decommission our jointly owned plants at the end of the useful life. The annual provision for such costs is included in depreciation expense, while the accumulated provisions are included in noncurrent regulatory liabilities.

Pension and Postretirement Benefits

We have liabilities under defined benefit retirement plans and a postretirement plan that offers certain health care and life insurance benefits to eligible employees and their dependents. The costs of these plans are dependent upon numerous factors, assumptions and estimates, including determination of discount rate, expected return on plan assets, rate of future compensation increases, age and mortality and employment periods. In determining the projected benefit obligations and costs, assumptions can change from period to period and may result in material changes in the cost and liabilities we recognize.

Accrued Expenses

Accrued expenses consisted of the following (in thousands):

	December 31,	
	2021	2020
Property taxes	$ 86,168	$ 89,425
Employee compensation, benefits, and withholdings	44,743	40,538
Customer advances	29,013	16,015
Interest	18,568	18,074
Other (none of which is individually significant)	54,859	43,462
Total Accrued Expenses	$ 233,351	$ 207,514

Other Noncurrent Liabilities

Other noncurrent liabilities consisted of the following (in thousands):

	December 31,	
	2021	2020
Pension and other employee benefits	$ 96,151	$ 136,632
Customer advances	80,780	65,186
Future QF obligation, net	64,943	81,379
Asset retirement obligations	38,350	45,355
Environmental	23,395	25,049
Other (none of which is individually significant)	65,700	57,102
Total Noncurrent Liabilities	$ 369,319	$ 410,703

Income Taxes

We follow the liability method in accounting for income taxes. Deferred income tax assets and liabilities represent the future effects on income taxes from temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to reverse. The probability of realizing deferred tax assets is based on forecasts of future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. We establish a valuation allowance when it is more likely than not that all, or a portion of, a deferred tax asset will not be realized.

Exposures exist related to various tax filing positions, which may require an extended period of time to resolve and may result in income tax adjustments by taxing authorities. We have reduced deferred tax assets or established liabilities based on our best estimate of future probable adjustments related to these exposures. On a quarterly basis, we evaluate exposures in light of any additional information and make adjustments as necessary to reflect the best estimate of the future outcomes. We believe our deferred tax assets and established liabilities are appropriate for estimated exposures; however, actual results may differ from these estimates. The resolution of tax matters in a particular future period could have a material impact on our Consolidated Income Statements and provision for income taxes.

Environmental Costs

We record environmental costs when it is probable we are liable for the costs and we can reasonably estimate the liability. We may defer costs as a regulatory asset if there is precedent for recovering similar costs from customers in rates. Otherwise, we expense the costs. If an environmental cost is related to facilities we currently use, such as pollution control equipment, then we may capitalize and depreciate the costs over the remaining life of the asset, assuming the costs are recoverable in future rates or future cash flows.

Our remediation cost estimates are based on the use of an environmental consultant, our experience, our assessment of the current situation and the technology currently available for use in the remediation. We regularly adjust the recorded costs as we revise estimates and as remediation proceeds. If we are one of several designated responsible parties, then we estimate and record only our share of the cost.

Supplemental Cash Flow Information

	Year Ended December 31,		
	2021	2020	2019
		(in thousands)	
Cash paid (received) for:			
Income taxes	$ 4,330	$ 115	$ (6,737)
Interest	87,221	84,922	83,776
Significant non-cash transactions:			
Capital expenditures included in trade accounts payable	29,034	21,430	33,473
NMTC debt extinguishment included in other noncurrent assets[1]	18,169	—	—
NMTC debt extinguishment included in property, plant and equipment, net[1]	6,594	—	—
NMTC debt extinguishment included in long-term debt[1]	1,259	—	—

(1) See Note 11 - Long-Term Debt and Finance Leases for further information regarding these non-cash transactions.

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

	December 31,		
	2021	2020	2019
Cash and cash equivalents	$ 2,820	$ 5,811	$ 5,145
Restricted cash	15,942	11,285	6,925
Total cash, cash equivalents, and restricted cash shown in the Consolidated Statements of Cash Flows	$ 18,762	$ 17,096	$ 12,070

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

Accounting Standards Issued

At this time, we are not expecting the adoption of recently issued accounting standards to have a material impact to our financial condition, results of operations, and cash flows.

(3) Regulatory Matters

Power Costs and Credits Adjustment Mechanism (PCCAM) - Montana

We track electric supply costs for our Montana electric utility, such as purchased power and fuel, against a forecast of costs approved by the MPSC. This forecast is referred to as the power costs and credits adjustment mechanism base (PCCAM Base). If our actual costs exceed the approved PCCAM Base revenues on an annual basis, we can recover 90% of the excess costs, with the non-recoverable 10% impacting net income. Our QF power purchase costs are recoverable through rates separate from the PCCAM Base. The MPSC reviews these costs annually, with NorthWestern receiving an automatic adjustment through interim rates, subject to refund, effective on October 1 of each year. During the twelve months ended December 31, 2021 we recognized $5.4 million of non-recoverable excess PCCAM supply costs, compared to $0.8 million of non-recoverable excess PCCAM supply costs for the twelve months ended December 31, 2020.

The current PCCAM Base, approved in 2019, no longer reflects an accurate current forecast of our fuel and power costs. In April 2021, we filed an application with the MPSC for approval to increase the PCCAM Base by approximately $17.0 million. On June 29, 2021, the MPSC approved interim rates reflecting our request, subject to refund. On August 2, 2021, the MCC filed a motion asking the MPSC to dismiss the application arguing that the MPSC issued a Final Order in 2018 prohibiting NorthWestern from requesting an update to the PCCAM Base, except in a general rate case. NorthWestern argued that the tariff, which the MPSC approved as implementing the Final Order, allows us to file an application outside of a general rate case. On October 5, 2021, the MPSC voted to grant the MCC's motion to dismiss. The MPSC issued the final written order on December 2, 2021, dismissing our application. As of December 31, 2021, we had deferred revenue of approximately $8.2 million, which we expect to refund in 2022, associated with these interim rates, including interest.

Montana Community Renewable Energy Projects (CREPs)

We were required to acquire, as of December 31, 2020, approximately 65 MW of CREPs. While we made progress towards meeting this obligation by acquiring approximately 50 MW of CREPs, we were unable to acquire the remaining MWs required for various reasons, including the fact that proposed projects fail to qualify as CREPs or do not meet the statutory cost cap. The MPSC granted us waivers for 2012 through 2016. The validity of the MPSC's action as it related to waivers granted for 2015 and 2016 has been challenged legally and was fully briefed before the Montana Supreme Court.

On May 14, 2021, the Montana Governor signed a bill that eliminated the state's Renewable Portfolio Standard, including repeal of the CREP requirement. We notified the Montana Supreme Court of the repeal. We also dismissed our pending application filed with the MPSC for a waiver from full compliance for years 2017 through 2020.

On September 7, 2021, the Montana Supreme Court remanded the case challenging the 2015 and 2016 waivers to the District Court to determine whether the repeal of the CREP requirement made the petition moot. The matter has been fully briefed before the District Court. In that briefing, the Montana Environmental Information Center requested the District Court to amend its previous judgment and penalize us $2.5 million for failure to comply with the CREP requirement in 2015 and 2016. We responded to this request arguing that it was unlawful for the District Court to penalize us. We expect a decision from the District Court in the first half of 2022.

If the Montana Courts and/or MPSC determine that the repeal should not be applied retroactively and find that waivers should not be granted, we could be liable for penalties. However, we do not believe any such penalties would be material.

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 has initiated a routine audit of NorthWestern Corporation for the period of January 1, 2018 to the present to evaluate our compliance with FERC accounting and financial reporting requirements. We have responded to several sets of data requests as part of the audit process. An audit report has not yet been received from FERC, but is expected during the first quarter of 2022. Management is unable to predict the outcome or timing of the final resolution of the audit.

(4) Regulatory Assets and Liabilities

We prepare our Consolidated Financial Statements in accordance with the provisions of ASC 980, as discussed in Note 2 - Significant Accounting Policies. Pursuant to this guidance, certain expenses and credits, normally reflected in income as incurred, are deferred and recognized when included in rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded based on management's assessment that it is probable that a cost will be recovered or that an obligation has been incurred. Accordingly, we have recorded the following major classifications of regulatory assets and liabilities that will be recognized in expenses and revenues in future periods when the matching revenues are collected or refunded. Of these regulatory assets and liabilities, energy supply costs are the only items earning a rate of return. The remaining regulatory items have corresponding assets and liabilities that will be paid for or refunded in future periods.

	Note Reference	Remaining Amortization Period	December 31, 2021	December 31, 2020
			(in thousands)	
Flow-through income taxes	12	Plant Lives	$ 464,663	$ 420,925
Excess deferred income taxes	12	Plant Lives	60,813	67,256
Pension	14	See Note 14	98,336	138,567
Deferred financing costs		Various	25,636	28,350
Employee related benefits	14	Various	21,648	22,516
Supply costs		18 months	88,329	8,116
State & local taxes & fees		Various	6,520	17,910
Environmental clean-up	18	Various	11,262	11,127
Other		Various	29,020	31,650
Total Regulatory Assets			**$ 806,227**	**$ 746,417**
Removal cost	6	Various	$ 479,294	$ 464,669
Excess deferred income taxes	12	Plant Lives	158,047	165,279
Supply costs		1 Year	16,430	13,847
Gas storage sales		18 years	7,466	7,887
Rates subject to refund		1 Year	1,971	32,496
State & local taxes & fees		1 Year	3,021	1,783
Environmental clean-up		Various	508	656
Other		Various	202	655
Total Regulatory Liabilities			**$ 666,939**	**$ 687,272**

Income Taxes

Flow-through income taxes primarily reflect the effects of plant related temporary differences such as flow-through of depreciation, repairs related deductions, and removal costs that we will recover or refund in future rates. We amortize these amounts as temporary differences reverse. Excess deferred income tax assets and liabilities are recorded as a result of the Tax Cuts and Jobs Act and will be recovered or refunded in future rates. See Note 12 - Income Taxes for further discussion.

Pension and Employee Related Benefits

We recognize the unfunded portion of plan benefit obligations in the Consolidated Balance Sheets, which is remeasured at each year end, with a corresponding adjustment to regulatory assets/liabilities as the costs associated with these plans are recovered in rates. The MPSC allows recovery of pension costs on a cash funding basis. The portion of the regulatory asset related to our Montana pension plan will amortize as cash funding amounts exceed accrual expense under GAAP. The SDPUC allows recovery of pension costs on an accrual basis. The MPSC allows recovery of postretirement benefit costs on an accrual basis.

Deferred Financing Costs

Consistent with our historical regulatory treatment, a regulatory asset has been established to reflect the remaining deferred financing costs on long-term debt that has been replaced through the issuance of new debt. These amounts are amortized over the life of the new debt.

Rates Subject to Refund

In May 2019, we submitted a filing with the FERC for our Montana transmission assets. In June 2019, the FERC issued an order accepting our filing, and granting interim rates (subject to refund) effective July 1, 2019. In November 2020, we filed a settlement and implemented settlement rates on December 1, 2020. In January 2021, the FERC approved our settlement and during the first quarter of 2021 we refunded approximately $20.5 million to our FERC regulated customers.

Revenues from FERC regulated customers associated with our Montana FERC assets are reflected in our MPSC jurisdictional rates as a credit to retail customers. In March 2021, we submitted a compliance filing with the MPSC adjusting the revenue credit in our Montana retail rates to reflect the FERC approved settlement rates and a refund to retail customers of the difference between the FERC interim rates and the FERC approved settlement rates that were collected during the period from July 1, 2019 through March 31, 2021. On May 19, 2021, the MPSC approved the proposed tariffs and rates on a final basis. During the second quarter of 2021, we recognized a $4.7 million favorable adjustment related to excess deferred revenues based on the final MPSC approval. As of December 31, 2021, we had cumulative deferred revenue remaining of approximately $2.0 million recorded as a regulatory liability on the Consolidated Balance Sheets.

Supply Costs

The MPSC, SDPUC and NPSC have authorized the use of electric and natural gas supply cost trackers that enable us to track actual supply costs and either recover the under collection or refund the over collection to our customers. Accordingly, we have recorded a regulatory asset and liability to reflect the future recovery of under collections and refunding of over collections through the ratemaking process. We earn interest on natural gas supply costs under collected, or apply interest to an over collection, of 7.0 percent in Montana; 7.2 percent and 7.8 percent for electric and natural gas, respectively, in South Dakota; and 8.5 percent for natural gas in Nebraska. We do not earn interest on our electric supply tracker, the PCCAM, in Montana.

State & Local Taxes & Fees (Montana Property Tax Tracker)

Under Montana law, we are allowed to track the changes in the actual level of state and local taxes and fees and recover the increase in rates, less the amount allocated to FERC jurisdictional customers and net of the related income tax benefit.

Environmental Clean-up

Environmental clean-up costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss the specific sites and clean-up requirements further in Note 18 - Commitments and Contingencies. Environmental clean-up costs are typically recoverable in customer rates when they are actually incurred. When cost projections become known and measurable, we coordinate with the appropriate regulatory authority to determine a recovery period.

Removal Cost

The anticipated costs of removing assets upon retirement are collected from customers in advance of removal activity as a component of depreciation expense. Our depreciation method, including cost of removal, is established by the respective regulatory commissions. Therefore, consistent with this regulated treatment, we reflect this accrual of removal costs for our regulated assets by increasing our regulatory liability. See Note 6 - Asset Retirement Obligations, for further information regarding this item.

Gas Storage Sales

A regulatory liability was established in 2000 and 2001 based on gains on cushion gas sales in Montana. This gain is being flowed to customers over a period that matches the depreciable life of surface facilities that were added to maintain deliverability from the field after the withdrawal of the gas. This regulatory liability is a reduction of rate base.

(5) Property, Plant and Equipment

The following table presents the major classifications of our property, plant and equipment (in thousands):

	Estimated Useful Life	December 31, 2021	December 31, 2020
	(years)	(in thousands)	
Transmission, distribution, and storage	15 – 95	$ 4,004,819	$ 3,771,023
Generation	23 – 72	1,287,517	1,252,805
Plant acquisition adjustment[1]	25 – 50	686,328	686,328
Building and improvements	23 – 73	296,955	303,099
Land, land rights and easements	53 – 96	161,585	157,379
Other	2 – 45	585,448	571,981
Construction work in process	—	294,617	173,492
Total property, plant and equipment		7,317,269	6,916,107
Less accumulated depreciation		(1,787,550)	(1,703,016)
Less accumulated amortization		(282,487)	(260,156)
Net property, plant and equipment		$ 5,247,232	$ 4,952,935

(1) The plant acquisition adjustment balance above includes our Beethoven wind project acquired in 2015, our hydro generating assets acquired in 2014, and the inclusion of our interest in Colstrip Unit 4 in rate base in 2009. The acquisition adjustment is amortized on a straight-line basis over the estimated remaining useful life of each related asset in depreciation expense.

Net plant and equipment under finance lease were $9.2 million and $11.3 million as of December 31, 2021 and 2020, respectively, which included $9.0 million and $11.1 million as of December 31, 2021 and 2020, respectively, related to a long-term power supply contract with the owners of a natural gas fired peaking plant, which has been accounted for as a finance lease.

Jointly Owned Electric Generating Plant

We have an ownership interest in four base-load electric generating plants, all of which are coal fired and operated by other companies. We have an undivided interest in these facilities and are responsible for our proportionate share of the capital and operating costs while being entitled to our proportionate share of the power generated. Our interest in each plant is reflected in the Consolidated Balance Sheets on a pro rata basis and our share of operating expenses is reflected in the Consolidated Statements of Income. The participants each finance their own investment.

Information relating to our ownership interest in these facilities is as follows (in thousands):

	Big Stone (SD)	Neal #4 (IA)	Coyote (ND)	Colstrip Unit 4 (MT)
December 31, 2021				
Ownership percentages	23.4 %	8.7 %	10.0 %	30.0 %
Plant in service	$ 154,375	$ 62,865	$ 51,652	$ 324,433
Accumulated depreciation	42,102	34,629	38,453	113,805
December 31, 2020				
Ownership percentages	23.4 %	8.7 %	10.0 %	30.0 %
Plant in service	$ 153,632	$ 62,927	$ 51,586	$ 317,438
Accumulated depreciation	40,665	33,942	37,980	105,738

(6) Asset Retirement Obligations

We are obligated to dispose of certain long-lived assets upon their abandonment. We recognize a liability for the legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event. We measure the liability at fair value when incurred and capitalize a corresponding amount as part of the book value of the related assets, which increases our property, plant and equipment and other noncurrent liabilities. The increase in the capitalized cost is included in determining depreciation expense over the estimated useful life of these assets. Since the fair value of the asset retirement obligation (ARO) is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period and recorded as a regulatory asset until the settlement of the liability. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates, and changes in the estimated timing of abandonment. If the obligation is settled for an amount other than the carrying amount of the liability, we will recognize a regulatory asset or liability for the difference, which will be surcharged/refunded to customers through the rate making process. We record regulatory assets and liabilities for differences in timing of asset retirement costs recovered in rates and AROs recorded since asset retirement costs are recovered through rates charged to customers.

Our AROs relate to the reclamation and removal costs at our jointly-owned coal-fired generation facilities, U.S. Department of Transportation requirements to cut, purge and cap retired natural gas pipeline segments, our obligation to plug and abandon oil and gas wells at the end of their life, and to remove all above-ground wind power facilities and restore the soil surface at the end of their life. The following table presents the change in our ARO (in thousands):

	December 31,		
	2021	2020	2019
Liability at January 1,	$ 45,355	$ 42,449	$ 40,659
Accretion expense	2,233	2,070	2,051
Liabilities incurred	—	—	—
Liabilities settled	(2,906)	(4,061)	(46)
Revisions to cash flows	(4,051)	4,897	(215)
Liability at December 31,	$ 40,631	$ 45,355	$ 42,449

During the twelve months ended December 31, 2021 our ARO liability decreased $2.9 million for partial settlement of the legal obligations at our jointly-owned coal-fired generation facilities. Additionally, during the twelve months ended December 31, 2021, our ARO liability decreased $4.1 million related to changes in both the timing and amount of retirement cost estimates.

In addition, we have identified removal liabilities related to our electric and natural gas transmission and distribution assets that have been installed on easements over property not owned by us. The easements are generally perpetual and only require remediation action upon abandonment or cessation of use of the property for the specified purpose. The ARO liability is not estimable for such easements as we intend to utilize these properties indefinitely. In the event we decide to abandon or cease the use of a particular easement, an ARO liability would be recorded at that time. We also identified AROs associated with our hydroelectric generating facilities; however, due to the indeterminate removal date, the fair value of the associated liabilities currently cannot be estimated and no amounts are recognized in the Consolidated Financial Statements.

We collect removal costs in rates for certain transmission and distribution assets that do not have associated AROs. Generally, the accrual of future non-ARO removal obligations is not required; however, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. The recorded amounts of costs collected from customers through depreciation rates are classified as a regulatory liability in recognition of the fact that we have collected these amounts that will be used in the future to fund asset retirement costs and do not represent legal retirement obligations. See Note 4 - Regulatory Assets and Liabilities for removal costs recorded as regulatory liabilities on the Consolidated Balance Sheets as of December 31, 2021 and 2020.

(7) Goodwill

We completed our annual goodwill impairment test as of April 1, 2021 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.

Goodwill by segment is as follows (in thousands):

	December 31,	
	2021	2020
Electric	$ 243,558	$ 243,558
Natural gas	114,028	114,028
Total Goodwill	$ 357,586	$ 357,586

(8) Risk Management and Hedging Activities

Nature of Our Business and Associated Risks

We are exposed to certain risks related to the ongoing operations of our business, including the impact of market fluctuations in the price of electricity and natural gas commodities and changes in interest rates. We rely on market purchases to fulfill a portion of our electric and natural gas supply requirements. Several factors influence price levels and volatility. These factors include, but are not limited to, seasonal changes in demand, weather conditions, available generating assets within regions, transportation availability and reliability within and between regions, fuel availability, market liquidity, and the nature and extent of current and potential federal and state regulations.

Objectives and Strategies for Using Derivatives

To manage our exposure to fluctuations in commodity prices we routinely enter into derivative contracts. These types of contracts are included in our electric and natural gas supply portfolios and are used to manage price volatility risk by taking advantage of fluctuations in market prices. While individual contracts may be above or below market value, the overall portfolio approach is intended to provide greater price stability for consumers. We do not maintain a trading portfolio, and our derivative transactions are only used for risk management purposes consistent with regulatory guidelines.

In addition, we may use interest rate swaps to manage our interest rate exposures associated with new debt issuances or to manage our exposure to fluctuations in interest rates on variable rate debt.

Accounting for Derivative Instruments

We evaluate new and existing transactions and agreements to determine whether they are derivatives. The permitted accounting treatments include: normal purchase normal sale (NPNS); cash flow hedge; fair value hedge; and mark-to-market. Mark-to-market accounting is the default accounting treatment for all derivatives unless they qualify, and we specifically designate them, for one of the other accounting treatments. Derivatives designated for any of the elective accounting treatments must meet specific, restrictive criteria both at the time of designation and on an ongoing basis. The changes in the fair value of recognized derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction and the type of hedge transaction.

Normal Purchases and Normal Sales

We have applied the NPNS scope exception to our contracts involving the physical purchase and sale of gas and electricity at fixed prices in future periods. During our normal course of business, we enter into full-requirement energy contracts, power purchase agreements and physical capacity contracts, which qualify for NPNS. All of these contracts are accounted for using the accrual method of accounting; therefore, there were no unrealized amounts recorded in the Consolidated Financial

Statements at December 31, 2021 and 2020. Revenues and expenses from these contracts are reported on a gross basis in the appropriate revenue and expense categories as the commodities are received or delivered.

Credit Risk

Credit risk is the potential loss resulting from counterparty non-performance under an agreement. We manage credit risk with policies and procedures for, among other things, counterparty analysis and exposure measurement, monitoring and mitigation. We limit credit risk in our commodity and interest rate derivatives activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis.

We are exposed to credit risk through buying and selling electricity and natural gas to serve customers. We may request collateral or other security from our counterparties based on the assessment of creditworthiness and expected credit exposure. It is possible that volatility in commodity prices could cause us to have material credit risk exposures with one or more counterparties. We enter into commodity master enabling agreements with our counterparties to mitigate credit exposure, as these agreements reduce the risk of default by allowing us or our counterparty the ability to make net payments. The agreements generally are: (1) Western Systems Power Pool agreements – standardized power purchase and sales contracts in the electric industry; (2) International Swaps and Derivatives Association agreements – standardized financial gas and electric contracts; (3) North American Energy Standards Board agreements – standardized physical gas contracts; and (4) Edison Electric Institute Master Purchase and Sale Agreements – standardized power sales contracts in the electric industry.

Many of our forward purchase contracts contain provisions that require us to maintain an investment grade credit rating from each of the major credit rating agencies. If our credit rating were to fall below investment grade, the counterparties could require immediate payment or demand immediate and ongoing full overnight collateralization on contracts in net liability positions.

Interest Rate Swaps Designated as Cash Flow Hedges

We have previously used interest rate swaps designated as cash flow hedges to manage our interest rate exposures associated with new debt issuances. We have no interest rate swaps outstanding. These swaps were designated as cash flow hedges with the effective portion of gains and losses, net of associated deferred income tax effects, recorded in AOCL. We reclassify these gains from AOCL into interest expense during the periods in which the hedged interest payments occur. The following table shows the effect of these interest rate swaps previously terminated on the Consolidated Financial Statements (in thousands):

Cash Flow Hedges	Location of Amount Reclassified from AOCL to Income	Amount Reclassified from AOCL into Income during the Year Ended December 31, 2021
Interest rate contracts	Interest Expense	$ 614

A pre-tax loss of approximately $14.0 million is remaining in AOCL as of December 31, 2021, and we expect to reclassify approximately $0.6 million of pre-tax losses from AOCL into interest expense during the next twelve months. These amounts relate to terminated swaps.

(9) Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (i.e., an exit price). Measuring fair value requires the use of market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, corroborated by market data, or generally unobservable. Valuation techniques are required to maximize the use of observable inputs and minimize the use of unobservable inputs.

Applicable accounting guidance establishes a hierarchy that prioritizes the inputs used to measure fair value, and requires fair value measurements to be categorized based on the observability of those inputs. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 inputs) and the lowest priority to unobservable inputs (Level 3 inputs). The three levels of the fair value hierarchy are as follows:

- Level 1 – Unadjusted quoted prices available in active markets at the measurement date for identical assets or liabilities;
- Level 2 – Pricing inputs, other than quoted prices included within Level 1, which are either directly or indirectly observable as of the reporting date; and
- Level 3 – Significant inputs that are generally not observable from market activity.

We classify assets and liabilities within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset and liability taken as a whole. Due to the short-term nature of cash and cash equivalents, accounts receivable, net, accounts payable, and short-term borrowings, the carrying amount of each such items approximates fair value. The table below sets forth by level within the fair value hierarchy the gross components of our assets and liabilities measured at fair value on a recurring basis. NPNS transactions are not included in the fair values by source table as they are not recorded at fair value. See Note 8 - Risk Management and Hedging Activities for further discussion.

We record transfers between levels of the fair value hierarchy, if necessary, at the end of the reporting period. There were no transfers between levels for the periods presented.

December 31, 2021	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Margin Cash Collateral Offset	Total Net Fair Value
			(in thousands)		
Restricted cash equivalents	$ 14,967	$ —	$ —	$ —	$ 14,967
Rabbi trust investments	18,234	—	—	—	18,234
Total	**$ 33,201**	**$ —**	**$ —**	**$ —**	**$ 33,201**
December 31, 2020					
Restricted cash equivalents	$ 10,055	$ —	$ —	$ —	$ 10,055
Rabbi trust investments	27,027	—	—	—	27,027
Total	**$ 37,082**	**$ —**	**$ —**	**$ —**	**$ 37,082**

Restricted cash equivalents represents amounts held in money market mutual funds. Rabbi trust investments represent assets held for non-qualified deferred compensation plans, which consist of our common stock and actively traded mutual funds with quoted prices in active markets.

Financial Instruments

The estimated fair value of financial instruments is summarized as follows (in thousands):

	December 31, 2021		December 31, 2020	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt	$ 2,541,478	$ 2,827,336	$ 2,315,261	$ 2,629,755

The estimated fair value amounts have been determined using available market information and appropriate valuation methodologies; however, considerable judgment is required in interpreting market data to develop estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we would realize in a current market exchange.

We determined fair value for long-term debt based on interest rates that are currently available to us for issuance of debt with similar terms and remaining maturities, except for publicly traded debt, for which fair value is based on market prices for the same or similar issues or upon the quoted market prices of U.S. treasury issues having a similar term to maturity, adjusted for our bond issuance rating and the present value of future cash flows. These are significant other observable inputs, or level 2 inputs, in the fair value hierarchy.

(10) Unsecured Credit Facilities

Credit Facility

We have a $425 million Credit Facility which matures September 2, 2023. The Credit Facility includes uncommitted features that allow us to request up to two one-year extensions to the maturity date and increase the size by an additional $75 million with the consent of the lenders. The facility does not amortize and is unsecured. Borrowings may be made at interest rates equal to the Eurodollar rate, plus a margin of 112.5 to 175.0 basis points, or a base rate, plus a margin of 12.5 to 75.0 basis points. A total of ten banks participate in the facility, with no one bank providing more than 16 percent of the total availability. Commitment fees for the Credit Facility were $0.4 million and $0.6 million for the years ended December 31, 2021 and 2020.

The availability under the facilities in place for the years ended December 31 is shown in the following table (in millions):

	2021	2020
Unsecured revolving line of credit, expiring September 2023	$ 425.0	$ 425.0
Unsecured revolving line of credit, expiring March 2023	25.0	25.0
	450.0	**450.0**
Amounts outstanding at December 31:		
Eurodollar borrowings	373.0	222.0
Letters of credit	—	—
	373.0	**222.0**
Net availability as of December 31	**$ 77.0**	**$ 228.0**

The Credit Facility includes covenants that require us to meet certain financial tests, including a maximum debt to capitalization ratio not to exceed 65 percent. The facility also contains covenants which, among other things, limit our ability to engage in any consolidation or merger or otherwise liquidate or dissolve, dispose of property, and enter into transactions with affiliates. A default on the South Dakota or Montana First Mortgage Bonds would trigger a cross default on the Credit Facility; however a default on the Credit Facility would not trigger a default on the South Dakota or Montana First Mortgage Bonds.

(11) Long-Term Debt and Finance Leases

Long-term debt and finance leases consisted of the following (in thousands):

	Due	December 31, 2021	December 31, 2020
Unsecured Debt:			
Unsecured Revolving Line of Credit	2023	$ 373,000	$ 222,000
Secured Debt:			
Mortgage bonds—			
South Dakota—5.01%	2025	64,000	64,000
South Dakota—4.15%	2042	30,000	30,000
South Dakota—4.30%	2052	20,000	20,000
South Dakota—4.85%	2043	50,000	50,000
South Dakota—4.22%	2044	30,000	30,000
South Dakota—4.26%	2040	70,000	70,000
South Dakota—3.21%	2030	50,000	50,000
South Dakota—2.80%	2026	60,000	60,000
South Dakota—2.66%	2026	45,000	45,000
Montana—5.71%	2039	55,000	55,000
Montana—5.01%	2025	161,000	161,000
Montana—4.15%	2042	60,000	60,000
Montana—4.30%	2052	40,000	40,000
Montana—4.85%	2043	15,000	15,000
Montana—3.99%	2028	35,000	35,000
Montana—4.176%	2044	450,000	450,000
Montana—3.11%	2025	75,000	75,000
Montana—4.11%	2045	125,000	125,000
Montana—4.03%	2047	250,000	250,000
Montana—3.98%	2049	150,000	150,000
Montana—3.21%	2030	100,000	100,000
Montana—1.00%	2024	100,000	—
Pollution control obligations—			
Montana—2.00%	2023	144,660	144,660
Other Long Term Debt:			
New Market Tax Credit Financing—1.146%	2046	—	26,977
Discount on Notes and Bonds and Debt Issuance Costs, Net	—	(11,182)	(13,376)
Total Long-Term Debt		$ 2,541,478	$ 2,315,261
Finance Leases:			
Total Finance Leases	Various	$ 14,772	$ 17,439
Less current maturities		(2,875)	(2,668)
Total Long-Term Finance Leases		$ 11,897	$ 14,771

Secured Debt

First Mortgage Bonds and Pollution Control Obligations

The South Dakota First Mortgage Bonds are a series of general obligation bonds issued under our South Dakota indenture. These bonds are secured by substantially all of our South Dakota and Nebraska electric and natural gas assets.

The Montana First Mortgage Bonds and Montana Pollution Control Obligations are secured by substantially all of our Montana electric and natural gas assets.

In May 2020, we issued $100 million principal amount of Montana First Mortgage Bonds and $50 million principal amount of South Dakota First Mortgage Bonds, each at a fixed interest rate of 3.21 percent maturing on May 15, 2030. These bonds were issued in a transaction exempt from the registration requirements of the Securities Act of 1933. Proceeds were used to repay a portion of our outstanding borrowings under our revolving credit facilities and for other general corporate purposes. The bonds are secured by our electric and natural gas assets in Montana and South Dakota.

In March 2021, we issued and sold $100.0 million aggregate principal amount of Montana First Mortgage Bonds (the bonds) at a fixed interest rate of 1.00 percent maturing on March 26, 2024. The net proceeds were used to repay in full our outstanding $100.0 million term loan that was due April 2, 2021. We may redeem some or all of the bonds at any time in whole, or from time to time in part, at our option, on or after March 26, 2022, at a redemption price equal to 100% of the principal amount of the bonds to be redeemed, plus accrued and unpaid interest on the principal amount of the bonds being redeemed to, but excluding, the redemption date. The bonds are secured by our electric and natural gas assets in Montana and Wyoming.

As of December 31, 2021, we were in compliance with our financial debt covenants.

Other Long-Term Debt

In July 2021, our two loans totaling $27.0 million associated with the New Market Tax Credit (NMTC) financing agreement were extinguished. These loans were satisfied with our $18.2 million investment in the entities created in relation to the NMTC transaction, investor forgiveness of $7.9 million for substantially all of the benefits derived from the tax credits, and cash payment of $0.9 million. In accordance with our last rate case filing in the state of Montana, the portion of the loan forgiven, less unamortized debt issuance costs of $1.3 million, was recorded as a reduction to the cost of the office building associated with the NMTC financing agreement. This cash payment is reflected within the financing activities section of our Consolidated Statement of Cash Flows for the year ended December 31, 2021; however, the remaining reduction to Long-term debt, Other noncurrent assets, and Property, plant and equipment are non-cash financing activities that are not reflected within our Consolidated Statement of Cash Flows for the year ended December 31, 2021.

Maturities of Long-Term Debt

The aggregate minimum principal maturities of long-term debt and finance leases, during the next five years are $2.9 million in 2022, $520.8 million in 2023, $103.3 million in 2024, $303.6 million in 2025 and $106.9 million in 2026.

(12) Income Taxes

Income tax expense (benefit) is comprised of the following (in thousands):

	Year Ended December 31,		
	2021	2020	2019
Federal			
Current	$ 722	$ (3,396)	$ (6,076)
Deferred	2,626	(4,006)	(15,169)
Investment tax credits	(130)	(3)	(12)
State			
Current	2,172	3	27
Deferred	(1,971)	(3,568)	1,305
Income Tax Expense (Benefit)	$ 3,419	$ (10,970)	$ (19,925)

Our effective tax rate typically differs from the federal statutory tax rate primarily 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 reconciles our effective income tax rate to the federal statutory rate:

	Year Ended December 31,		
	2021	2020	2019
Federal statutory rate	21.0 %	21.0 %	21.0 %
State income tax, net of federal provisions	0.1	(1.1)	0.7
Flow-through repairs deductions	(11.5)	(16.5)	(10.8)
Production tax credits	(6.1)	(9.1)	(6.3)
Plant and depreciation of flow through items	(0.6)	0.1	(2.2)
Amortization of excess DIT	(0.3)	(0.7)	(0.9)
Recognition of unrecognized tax benefit	—	—	(12.5)
Impact of Tax Cuts and Jobs Act	—	—	(0.1)
Prior year permanent return to accrual adjustments	0.0	(1.2)	0.3
Other, net	(0.8)	(0.1)	(0.1)
Effective tax rate	1.8 %	(7.6)%	(10.9)%

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

	Year Ended December 31,		
	2021	2020	2019
Income Before Income Taxes	$ 190,259	$ 144,245	$ 182,195
Income tax calculated at federal statutory rate	39,954	30,292	38,261
Permanent or flow through adjustments:			
State income, net of federal provisions	354	(1,477)	1,251
Flow-through repairs deductions	(21,888)	(23,828)	(19,706)
Production tax credits	(11,532)	(13,103)	(11,483)
Plant and depreciation of flow through items	(941)	121	(3,952)
Amortization of excess DIT	(635)	(968)	(1,688)
Prior year permanent return to accrual adjustments	(12)	(1,728)	559
Recognition of unrecognized tax benefit	—	—	(22,825)
Impact of Tax Cuts and Jobs Act	—	—	(198)
Other, net	(1,881)	(279)	(144)
	(36,535)	(41,262)	(58,186)
Income Tax Expense (Benefit)	$ 3,419	$ (10,970)	$ (19,925)

The income tax benefit during the twelve months ended December 31, 2019, reflects the release of approximately $22.8 million of unrecognized tax benefits, including approximately $2.7 million of accrued interest and penalties, net of tax, due to the lapse of statutes of limitation in the second quarter of 2019.

The components of the net deferred income tax liability recognized in our Consolidated Balance Sheets are related to the following temporary differences (in thousands):

	December 31,	
	2021	2020
Production tax credit	$ 75,092	$ 63,542
Pension / postretirement benefits	21,435	31,866
Customer advances	21,271	17,165
Unbilled revenue	10,704	14,429
Compensation accruals	10,612	11,748
Reserves and accruals	5,106	6,266
Environmental liability	5,704	6,039
Interest rate hedges	3,158	3,171
NOL carryforward	—	393
Other, net	1,738	2,490
Deferred Tax Asset	**154,820**	**157,109**
Excess tax depreciation	(425,202)	(412,774)
Goodwill amortization	(85,425)	(83,991)
Flow through depreciation	(94,616)	(83,545)
Regulatory assets and other	(49,211)	(48,576)
Deferred Tax Liability	**(654,454)**	**(628,886)**
Deferred Tax Liability, net	**$ (499,634)**	**$ (471,777)**

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. The change in unrecognized tax benefits is as follows (in thousands):

	2021	2020	2019
Unrecognized Tax Benefits at January 1	$ 33,491	$ 35,085	$ 56,150
Gross increases - tax positions in prior period	293	120	539
Gross increases - tax positions in current period	—	—	—
Gross decreases - tax positions in current period	(1,735)	(1,714)	(1,489)
Lapse of statute of limitations	—	—	(20,115)
Unrecognized Tax Benefits at December 31	$ 32,049	$ 33,491	$ 35,085

Our unrecognized tax benefits include approximately $28.1 million and $28.0 million related to tax positions as of December 31, 2021 and 2020, that if recognized, would impact our annual 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 December 31, 2021, we have accrued $0.5 million for the payment of interest and penalties in the Consolidated Balance Sheets. As of December 31, 2020, we did not have any amounts accrued for the payment of interest and penalties.

Tax years 2018 and forward remain subject to examination by the IRS and state taxing authorities.

(13) Comprehensive Income (Loss)

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

	December 31,								
	2021			2020			2019		
	Before-Tax Amount	Tax Expense (Benefit)	Net-of-Tax Amount	Before-Tax Amount	Tax Expense	Net-of-Tax Amount	Before-Tax Amount	Tax Expense	Net-of-Tax Amount
Foreign currency translation adjustment	$ (57)	$ —	$ (57)	$ 87	$ —	$ 87	$ (35)	$ —	$ (35)
Reclassification of net income (loss) on derivative instruments	614	(162)	452	614	(162)	452	614	(162)	452
Postretirement medical liability adjustment	(585)	149	(436)	2,463	(623)	1,840	(175)	44	(131)
Other comprehensive (loss) income	$ (28)	$ (13)	$ (41)	$ 3,164	$ (785)	$ 2,379	$ 404	$ (118)	$ 286

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

	December 31,	
	2021	2020
Foreign currency translation	$ 1,443	$ 1,500
Derivative instruments designated as cash flow hedges	(10,277)	(10,729)
Postretirement medical plans	1,524	1,960
Accumulated other comprehensive loss	$ (7,310)	$ (7,269)

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

	Affected Line Item in the Consolidated Statements of Income	Year Ended December 31, 2021 Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (10,729)	$ 1,960	$ 1,500	$ (7,269)
Other comprehensive loss before reclassifications		—	—	(57)	(57)
Amounts reclassified from AOCL	Interest Expense	452	—	—	452
Amounts reclassified from AOCL		—	(436)	—	(436)
Net current-period other comprehensive income (loss)		452	(436)	(57)	(41)
Ending Balance		$ (10,277)	$ 1,524	$ 1,443	$ (7,310)

	Affected Line Item in the Consolidated Statements of Income	Year Ended December 31, 2020 Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (11,181)	$ 120	$ 1,413	$ (9,648)
Other comprehensive income before reclassifications		—	—	87	87
Amounts reclassified from AOCL	Interest Expense	452	—	—	452
Amounts reclassified from AOCL		—	1,840	—	1,840
Net current-period other comprehensive income		452	1,840	87	2,379
Ending Balance		$ (10,729)	$ 1,960	$ 1,500	$ (7,269)

(14) Employee Benefit Plans

Pension and Other Postretirement Benefit Plans

We sponsor and/or contribute to pension and postretirement health care and life insurance benefit plans for eligible employees. The pension plan for our South Dakota and Nebraska employees is referred to as the NorthWestern Corporation plan, and the pension plan for our Montana employees is referred to as the NorthWestern Energy plan, and collectively they are referred to as the Plans. We utilize a number of accounting mechanisms that reduce the volatility of reported pension costs. Differences between actuarial assumptions and actual plan results are deferred and are recognized into earnings only when the accumulated differences exceed 10 percent of the greater of the projected benefit obligation or the market-related value of plan assets. If necessary, the excess is amortized over the average remaining service period of active employees. The Plans' funded status is recognized as an asset or liability in our Consolidated Financial Statements. See Note 4 - Regulatory Assets and Liabilities, for further discussion on how these costs are recovered through rates charged to our customers.

Benefit Obligation and Funded Status

Following is a reconciliation of the changes in plan benefit obligations and fair value of plan assets, and a statement of the funded status (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2021	2020	2021	2020
Change in benefit obligation:				
Obligation at beginning of period	$ 820,979	$ 735,564	$ 19,146	$ 20,272
Service cost	12,994	11,116	407	370
Interest cost	18,759	22,840	317	492
Actuarial loss	(28,905)	84,479	415	123
Settlements(1)	(93,488)	—	—	390
Benefits paid	(33,537)	(33,020)	(2,977)	(2,501)
Benefit Obligation at End of Period	$ 696,802	$ 820,979	$ 17,308	$ 19,146
Change in Fair Value of Plan Assets:				
Fair value of plan assets at beginning of period	$ 688,456	$ 609,000	$ 23,096	$ 21,479
Return on plan assets	33,868	101,075	3,349	2,723
Employer contributions	10,200	11,401	1,821	1,395
Settlements(1)	(93,488)	—	—	—
Benefits paid	(33,537)	(33,020)	(2,977)	(2,501)
Fair value of plan assets at end of period	$ 605,499	$ 688,456	$ 25,289	$ 23,096
Funded Status	$ (91,303)	$ (132,523)	$ 7,981	$ 3,950
Amounts Recognized in the Balance Sheet Consist of:				
Noncurrent asset	8,297	7,001	11,914	8,436
Total Assets	8,297	7,001	11,914	8,436
Current liability	(11,200)	(11,200)	(1,575)	(1,712)
Noncurrent liability	(88,400)	(128,324)	(2,358)	(2,774)
Total Liabilities	(99,600)	(139,524)	(3,933)	(4,486)
Net amount recognized	$ (91,303)	$ (132,523)	$ 7,981	$ 3,950
Amounts Recognized in Regulatory Assets Consist of:				
Prior service credit	—	—	1,870	3,857
Net actuarial loss	(62,448)	(115,987)	1,366	(497)
Amounts recognized in AOCL consist of:				
Prior service cost	—	—	(95)	(246)
Net actuarial gain	—	—	2,500	3,246
Total	$ (62,448)	$ (115,987)	$ 5,641	$ 6,360

(1) In December 2021, we entered into a group annuity contract from an insurance company to provide for the payment of pension benefits to 1,062 NorthWestern Energy Pension Plan participants. We purchased the contract with $93.5 million of plan assets. The insurance company took over the payments of these benefits starting January 1, 2022. This transaction settled $93.5 million of our NorthWestern Energy Pension Plan obligation. As a result of this transaction, during the twelve months ended December 31, 2021, we recorded a non-cash, non-operating settlement charge of $11.3 million. This charge is recorded within other income, net on the Consolidated Statements of Income. As discussed within Note 4 – Regulatory Assets and Liabilities, this charge was deferred as a regulatory asset on the Consolidated Balance Sheets, with a corresponding decrease to operating and maintenance expense on the Consolidated Statements of Income.

The actuarial gain/loss is primarily due to the change in discount rate assumption and actual asset returns compared with expected amounts. The total projected benefit obligation and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets were as follows (in millions):

	NorthWestern Energy Pension Plan	
	December 31,	
	2021	2020
Projected benefit obligation	$ 636.3	$ 757.4
Accumulated benefit obligation	636.3	757.4
Fair value of plan assets[(1)]	537.9	619.1

As of December 31, 2021, the fair value of the NorthWestern Corporation pension plan assets exceed the total projected and accumulated benefit obligation and are therefore excluded from this table.

(1) Fair value of plan assets was impacted by the group annuity contract discussed above.

Net Periodic Cost (Credit)

The components of the net costs (credits) for our pension and other postretirement plans are as follows (in thousands):

	Pension Benefits			Other Postretirement Benefits		
	December 31,			December 31,		
	2021	2020	2019	2021	2020	2019
Components of Net Periodic Benefit Cost						
Service cost	$ 12,994	$ 11,116	$ 9,637	$ 407	$ 370	$ 331
Interest cost	18,759	22,840	26,488	327	492	609
Expected return on plan assets	(27,061)	(26,162)	(25,443)	(919)	(983)	(869)
Amortization of prior service cost (credit)	—	—	—	(1,835)	(1,882)	(1,882)
Recognized actuarial loss (gain)	6,536	5,028	6,544	(898)	(61)	(96)
Settlement loss recognized[(1)]	11,291	—	198	—	390	390
Net Periodic Benefit Cost (Credit)	$ 22,519	$ 12,822	$ 17,424	$ (2,918)	$ (1,674)	$ (1,517)
Regulatory deferral of net periodic benefit cost[(2)]	(13,308)	(2,100)	(7,510)	—	—	—
Previously deferred costs recognized[(2)]	—	71	728	709	861	931
Amount Recognized in Income	$ 9,211	$ 10,793	$ 10,642	$ (2,209)	$ (813)	$ (586)
Income Statement Presentation						
Operating and maintenance	(313)	9,016	2,125	407	370	331
Other income (expense), net	9,524	1,777	8,517	(2,616)	(1,183)	(917)
Amount Recognized in Income	$ 9,211	$ 10,793	$ 10,642	$ (2,209)	$ (813)	$ (586)

(1) Settlement loss is related to partial annuitization of NorthWestern Energy Pension Plan effective December 1, 2021.

(2) Net periodic benefit costs for pension and postretirement benefit plans are recognized for financial reporting based on the authorization of each regulatory jurisdiction in which we operate. A portion of these costs are recorded in regulatory assets and recognized in the Consolidated Statements of Income as those costs are recovered through customer rates.

For purposes of calculating the expected return on pension plan assets, the market-related value of assets is used, which is based upon fair value. The difference between actual plan asset returns and estimated plan asset returns are amortized equally over a period not to exceed five years.

Actuarial Assumptions

The measurement dates used to determine pension and other postretirement benefit measurements for the plans are December 31, 2021 and 2020. The actuarial assumptions used to compute net periodic pension cost and postretirement benefit cost are based upon information available as of the beginning of the year, specifically, market interest rates, past experience and management's best estimate of future economic conditions. Changes in these assumptions may impact future benefit costs and obligations. In computing future costs and obligations, we must make assumptions about such things as employee mortality and turnover, expected salary and wage increases, discount rate, expected return on plan assets, and expected future cost increases. Two of these assumptions have the most impact on the level of cost: (1) discount rate and (2) expected rate of return on plan assets.

On an annual basis, we set the discount rate using a yield curve analysis. This analysis includes constructing a hypothetical bond portfolio whose cash flow from coupons and maturities matches the year-by-year, projected benefit cash flow from our plans. The increase in the discount rate during 2021 decreased our projected benefit obligation by approximately $45.1 million.

In determining the expected long-term rate of return on plan assets, we review historical returns, the future expectations for returns for each asset class weighted by the target asset allocation of the pension and postretirement portfolios, and long-term inflation assumptions. Based on the target asset allocation for our pension assets and future expectations for asset returns, we increased our long term rate of return on assets assumption for NorthWestern Energy Pension Plan to 4.26 percent and decreased our assumption on the NorthWestern Corporation Pension Plan to 2.66 percent for 2022.

The weighted-average assumptions used in calculating the preceding information are as follows:

	Pension Benefits			Other Postretirement Benefits		
	December 31,			December 31,		
	2021	2020	2019	2021	2020	2019
Discount rate	2.65-2.75 %	2.20-2.30 %	3.10-3.20 %	2.35-2.40 %	1.80 %	2.80 %
Expected rate of return on assets	3.01-4.17	3.45-4.49	4.23-5.06	4.08	4.71	4.79
Long-term rate of increase in compensation levels (non-union)	2.84	2.84	2.84	2.84	2.84	2.84
Long-term rate of increase in compensation levels (union)	2.00	2.00	2.00	2.00	2.00	2.00
Interest crediting rate	3.30-6.00	3.30-6.00	3.60-6.00	N/A	N/A	N/A

The postretirement benefit obligation is calculated assuming that health care costs increase by a 5.00 percent fixed rate. The company contribution toward the premium cost is capped, therefore future health care cost trend rates are expected to have a minimal impact on company costs and the accumulated postretirement benefit obligation.

Investment Strategy

Our investment goals with respect to managing the pension and other postretirement assets are to meet current and future benefit payment needs while maximizing total investment returns (income and appreciation) after inflation within the constraints of diversification, prudent risk taking, Prudent Man Rule of the Employee Retirement Income Security Act of 1974 and liability-based considerations. Each plan is diversified across asset classes to achieve optimal balance between risk and return and between income and growth through capital appreciation. Our investment philosophy is based on the following:

- Each plan should be substantially invested as long-term cash holdings reduce long-term rates of return;
- Pension Plan portfolio risk is described by volatility in the funded status of the Plans;
- It is prudent to diversify each plan across the major asset classes;
- Equity investments provide greater long-term returns than fixed income investments, although with greater short-term volatility;
- Fixed income investments of the plans should strongly correlate with the interest rate sensitivity of the plan's aggregate liabilities in order to hedge the risk of change in interest rates negatively impacting the pension plans overall funded status, (such assets will be described as Liability Hedging Fixed Income assets);

- Allocation to foreign equities increases the portfolio diversification and thereby decreases portfolio risk while providing for the potential for enhanced long-term returns;
- Active management can reduce portfolio risk and potentially add value through security selection strategies;
- A portion of plan assets should be allocated to passive, indexed management funds to provide for greater diversification and lower cost; and
- It is appropriate to retain more than one investment manager, provided that such managers offer asset class or style diversification.

Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

The most important component of an investment strategy is the portfolio asset mix, or the allocation between the various classes of securities available. The mix of assets is based on an optimization study that identifies asset allocation targets in order to achieve the maximum return for an acceptable level of risk, while minimizing the expected contributions and pension and postretirement expense. In the optimization study, assumptions are formulated about characteristics, such as expected asset class investment returns, volatility (risk), and correlation coefficients among the various asset classes, and making adjustments to reflect future conditions expected to prevail over the study period. Based on this, the target asset allocation established, within an allowable range of plus or minus 5 percent, is as follows:

	NorthWestern Energy Pension		NorthWestern Corporation Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2021	2020	2021	2020	2021	2020
Fixed income securities	55.0 %	55.0 %	90.0 %	80.0 %	40.0 %	40.0 %
Non-U.S. fixed income securities	4.0	4.0	1.0	2.0	—	—
Global equities	41.0	41.0	9.0	18.0	60.0	60.0

The actual allocation by plan is as follows:

	NorthWestern Energy Pension		NorthWestern Corporation Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2021	2020	2021	2020	2021	2020
Cash and cash equivalents	0.1 %	— %	0.4 %	0.7 %	0.1 %	1.0 %
Fixed income securities	53.8	52.7	89.5	77.3	33.7	37.9
Non-U.S. fixed income securities	3.9	3.8	0.9	2.6	—	—
Global equities	42.2	43.5	9.2	19.4	66.2	61.1
	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %

Generally, the asset mix will be rebalanced to the target mix as individual portfolios approach their minimum or maximum levels. Debt securities consist of U.S. and international instruments. Core domestic portfolios can be invested in government, corporate, asset-backed and mortgage-backed obligation securities. While the portfolio may invest in high yield securities, the average quality must be rated at least “investment grade" by rating agencies. Performance of fixed income investments is measured by both traditional investment benchmarks as well as relative changes in the present value of the plan's liabilities. Equity investments consist primarily of U.S. stocks including large, mid and small cap stocks, which are diversified across investment styles such as growth and value. We also invest in global equities with exposure to developing and emerging markets. Derivatives, options and futures are permitted for the purpose of reducing risk but may not be used for speculative purposes.

Our plan assets are primarily invested in common collective trusts (CCTs), which are invested in equity and fixed income securities. In accordance with our investment policy, these pooled investment funds must have an adequate asset base relative to their asset class and be invested in a diversified manner and have a minimum of three years of verified investment performance experience or verified portfolio manager investment experience in a particular investment strategy and have management and oversight by an investment advisor registered with the SEC. Investments in a collective investment vehicle are valued by multiplying the investee company’s net asset value per share with the number of units or shares owned at the valuation date. Net asset value per share is determined by the trustee. Investments held by the CCT, including collateral invested for securities on loan, are valued on the basis of valuations furnished by a pricing service approved by the CCT's investment manager, which determines valuations using methods based on quoted closing market prices on national securities exchanges, or at fair value as determined in good faith by the CCT's investment manager if applicable. The funds do not contain any redemption restrictions. The direct holding of NorthWestern Corporation stock is not permitted; however, any holding in a diversified mutual fund or collective investment fund is permitted. During 2019, due to proposed changes in the John Hancock participating group annuity contract held by the NorthWestern Corporation plan, we elected to discontinue the contract effective January 1, 2020.

Cash Flows

In accordance with the Pension Protection Act of 2006 (PPA), and the relief provisions of the Worker, Retiree, and Employer Recovery Act of 2008 (WRERA), we are required to meet minimum funding levels in order to avoid required contributions and benefit restrictions. We have elected to use asset smoothing provided by the WRERA, which allows the use of asset averaging, including expected returns (subject to certain limitations), for a 24-month period in the determination of funding requirements. Additional funding relief was passed in the American Rescue Plan Act of 2021, providing for longer amortization and interest rate smoothing, which we elected to use. We expect to continue to make contributions to the pension plans in 2022 and future years that reflect the minimum requirements and discretionary amounts consistent with the amounts recovered in rates. Additional legislative or regulatory measures, as well as fluctuations in financial market conditions, may impact our funding requirements.

Due to the regulatory treatment of pension costs in Montana, pension expense for 2021, 2020 and 2019 was based on actual contributions to the plan. Annual contributions to each of the pension plans are as follows (in thousands):

	2021	2020	2019
NorthWestern Energy Pension Plan (MT)	$ 9,000	$ 10,201	$ 9,000
NorthWestern Corporation Pension Plan (SD and NE)	1,200	1,200	1,200
	$ 10,200	$ 11,401	$ 10,200

We estimate the plans will make future benefit payments to participants as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
2022	$ 28,842	$ 2,579
2023	30,368	2,296
2024	31,933	1,952
2025	33,410	1,435
2026	34,692	1,381
2027-2031	183,671	5,352

Defined Contribution Plan

Our defined contribution plan permits employees to defer receipt of compensation as provided in Section 401(k) of the Internal Revenue Code. Under the plan, employees may elect to direct a percentage of their gross compensation to be contributed to the plan. We contribute various percentage amounts of the employee's gross compensation contributed to the plan. Matching contributions for the years ended December 31, 2021, 2020 and 2019 were $11.8 million, $11.1 million, and $11.0 million, respectively.

(15) Stock-Based Compensation

We grant stock-based awards through our Amended and Restated Equity Compensation Plan (ECP), which includes restricted stock awards and performance share awards. As of December 31, 2021, there were 828,486 shares of common stock remaining available for grants. The remaining vesting period for awards previously granted ranges from one to five years if the service and/or performance requirements are met. Nonvested shares do not receive dividend distributions. The long-term incentive plan provides for accelerated vesting in the event of a change in control.

We account for our share-based compensation arrangements by recognizing compensation costs for all share-based awards over the respective service period for employee services received in exchange for an award of equity or equity-based compensation. The compensation cost is based on the fair value of the grant on the date it was awarded.

Performance Unit Awards

Performance unit awards are granted annually under the ECP. These awards vest at the end of the three-year performance period if we have achieved certain performance goals and the individual remains employed by us. The exact number of shares issued will vary from 0 percent to 200 percent of the target award, depending on actual company performance relative to the performance goals. These awards contain both market- and performance-based components. The performance goals are independent of each other and equally weighted, and are based on two metrics: (i) EPS growth level and average return on equity; and (ii) total shareholder return (TSR) relative to a peer group.

Fair value is determined for each component of the performance unit awards. The fair value of the earnings per share component is estimated based upon the closing market price of our common stock as of the date of grant less the present value of expected dividends, multiplied by an estimated performance multiple determined on the basis of historical experience, which is subsequently trued up at vesting based on actual performance. The fair value of the TSR portion is estimated using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. The following summarizes the significant assumptions used to determine the fair value of performance shares and related compensation expense as well as the resulting estimated fair value of performance shares granted:

	2021	2020
Risk-free interest rate	0.19 %	1.42 %
Expected life, in years	3	3
Expected volatility	28.2% to 38.5%	14.9% to 19.7%
Dividend yield	4.3 %	3.1 %

The risk-free interest rate was based on the U.S. Treasury yield of a three-year bond at the time of grant. The expected term of the performance shares is three years based on the performance cycle. Expected volatility was based on the historical volatility for the peer group. Both performance goals are measured over the three-year vesting period and are charged to compensation expense over the vesting period based on the number of shares expected to vest.

A summary of nonvested shares as of and changes during the year ended December 31, 2021, are as follows:

	Performance Unit Awards	
	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	130,571	$ 66.27
Granted	104,927	50.53
Vested	(69,867)	60.41
Forfeited	(3,108)	59.14
Remaining nonvested grants	162,523	$ 58.76

We recognized compensation expense of $3.9 million, $2.2 million, and $6.5 million for the years ended December 31, 2021, 2020, and 2019, respectively, and related income tax (benefit) expense of $(0.2) million, $(0.6) million, and $0.2 million for the years ended December 31, 2021, 2020, and 2019, respectively. As of December 31, 2021, we had $5.7 million of unrecognized compensation cost related to the nonvested portion of outstanding awards, which is reflected as nonvested stock as a portion of additional paid in capital in our Statements of Common Shareholders' Equity. The cost is expected to be recognized over a weighted-average period of 2 years. The total fair value of shares vested was $4.2 million, $5.1 million, and $4.2 million for the years ended December 31, 2021, 2020 and 2019, respectively.

Retirement/Retention Restricted Share Awards

In December 2011, an executive retirement / retention program was established that provides for the annual grant of restricted share units. These awards are subject to a five-year performance and vesting period. The performance measure for these awards requires net income for the calendar year of at least three of the five full calendar years during the performance period to exceed net income for the calendar year the awards are granted. Once vested, the awards will be paid out in shares of common stock in five equal annual installments after a recipient has separated from service. The fair value of these awards is measured based upon the closing market price of our common stock as of the date of grant less the present value of expected dividends.

A summary of nonvested shares as of and changes during the year ended December 31, 2021, are as follows:

	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	77,967	$ 50.86
Granted	24,385	43.29
Vested	(15,033)	45.78
Forfeited	—	—
Remaining nonvested grants	87,319	$ 49.63

Director's Deferred Compensation

Nonemployee directors may elect to defer up to 100 percent of any qualified compensation that would be otherwise payable to him or her, subject to compliance with our 2005 Deferred Compensation Plan for Nonemployee Directors and Section 409A of the Internal Revenue Code. The deferred compensation may be invested in NorthWestern stock or in designated investment funds. Compensation deferred in a particular month is recorded as a deferred stock unit (DSU) on the first of the following month based on the closing price of NorthWestern stock or the designated investment fund. The DSUs are marked-to-market on a quarterly basis with an adjustment to director’s compensation expense. Based on the election of the nonemployee director, following separation from service on the Board, other than on account of death, he or she shall be paid a distribution either in a lump sum or in approximately equal installments over a designated number of years (not to exceed 10 years).

Following is a summary of the components of DSUs issued and compensation expense attributable to the DSUs (in millions, except DSU amounts):

	December 31,		
	2021	2020	2019
DSUs Issued	18,741	21,434	19,027
Compensation expense	$ 1.1	$ 1.5	$ 1.3
Change in value of shares	1.3	(2.9)	2.4
Total compensation (benefit) expense	$ 2.4	$ (1.4)	$ 3.7
DSUs withdrawn	186,137	613	3,708
Value of DSUs withdrawn	$ 12.1	$ 0.1	$ 0.3

(16) Common Stock

We have 250,000,000 shares authorized consisting of 200,000,000 shares of common stock with a $0.01 par value and 50,000,000 shares of preferred stock with a $0.01 par value. Of these shares, 2,865,957 shares of common stock are reserved for the incentive plan awards. For further detail of grants under this plan see Note 15 - Stock-Based Compensation.

Repurchase of Common Stock

Shares tendered by employees to us to satisfy the employees' tax withholding obligations in connection with the vesting of restricted stock awards totaled 16,880 and 35,378 during the years ended December 31, 2021 and 2020, respectively, and are reflected in treasury stock. These shares were credited to treasury stock based on their fair market value on the vesting date.

Issuance of Common Stock

In April 2021, we entered into an Equity Distribution Agreement with BofA Securities, Inc., CIBC World Markets Corp, Credit Suisse Securities (USA) LLC, and J.P. Morgan Securities LLC, collectively the sales agents, pursuant to which we may offer and sell shares of our common stock from time to time, having an aggregate gross sales price of up to $200.0 million, through an At-the-Market (ATM) offering program, including an equity forward sales component. This is a three-year agreement, expiring on February 11, 2024. During the twelve months ended December 31, 2021, we issued 1,966,117 shares of our common stock under the ATM program at an average price of $63.81, for net proceeds of $124.2 million, which is net of sales commissions and other fees paid of approximately $1.3 million. We do not anticipate needing to issue equity through the ATM program during 2022.

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, $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 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.

At December 31, 2021, we could have settled the forward sale agreement with physical delivery of 5,584,113 shares of common stock to the counterparty in exchange for cash of $286.1 million. The forward sale could have also been settled at December 31, 2021, with delivery of approximately $24.2 million of cash or approximately 435,522 shares of common stock to the counterparty, if we had elected to net cash or net share settle, respectfully.

The forward sale agreement has been classified as an equity transaction because it is indexed to our common stock, physical settlement is within our control, and the other requirements necessary for equity classification are met. As a result of the equity classification, no gain or loss will be recognized within earnings due to subsequent changes in the fair value of the forward sales agreement. If the average price of our common stock exceeds the adjusted forward sales price during a quarterly period, the forward sales agreement could have a dilutive effect on earnings per share.

(17) Earnings Per Share

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

	December 31,		
	2021	2020	2019
Basic computation	51,709,229	50,559,208	50,428,560
Dilutive effect of			
Performance and restricted share awards[1]	111,940	145,181	323,298
Forward equity sale	51,057	—	—
Diluted computation	51,872,226	50,704,389	50,751,858

(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.

As of December 31, 2021, there were 77,856 shares from performance and restricted share awards which were antidilutive and excluded from the earnings per share calculations.

(18) Commitments and Contingencies

Qualifying Facilities Liability

Our QF liability primarily consists of unrecoverable costs associated with three contracts covered under the PURPA. These contracts require us to purchase minimum amounts of energy at prices ranging from $64 to $136 per MWH through 2029. As of December 31, 2021, our estimated gross contractual obligation related to these contracts was approximately $466.9 million through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $388.4 million through 2029. As contractual obligations are settled, the related purchases and sales are recorded within Fuel, purchased power and direct transmission expense and Electric revenues in our Consolidated Statements of Income. The present value of the remaining liability is recorded in Other noncurrent liabilities in our Consolidated Balance Sheets. The following summarizes the change in the liability (in thousands):

	December 31,	
	2021	2020
Beginning QF liability	$ 81,379	$ 92,937
Settlements[1]	(22,497)	(18,665)
Interest expense	6,061	7,107
Ending QF liability	$ 64,943	$ 81,379

(1) The settlements amount includes (i) a higher periodic adjustment of $4.3 million due to actual price escalation, which was more than previously modeled; (ii) lower costs of approximately $1.7 million, due to a $2.6 million reduction in costs for the adjustment to actual output and pricing for the current contract year as compared with a $0.9 million reduction in costs in the prior period; and (iii) a favorable adjustment of approximately $7.0 million decreasing the QF liability associated with a one-time clarification in contract term.

The following summarizes the estimated gross contractual obligation less amounts recoverable through rates (in thousands):

	Gross Obligation	Recoverable Amounts	Net
2022	$ 80,355	$ 60,639	$ 19,716
2023	82,452	61,280	21,172
2024	75,113	60,706	14,407
2025	60,360	52,950	7,410
2026	55,393	46,274	9,119
Thereafter	113,199	106,563	6,636
Total[1]	$ 466,872	$ 388,412	$ 78,460

(1) This net unrecoverable amount represents the undiscounted difference between the total gross obligations and recoverable amounts. The ending QF liability in the table above represents the present value of this net unrecoverable amount.

Long Term Supply and Capacity Purchase Obligations

We have entered into various commitments, largely purchased power, electric transmission, coal and natural gas supply and natural gas transportation contracts. These commitments range from one to 24 years. Costs incurred under these contracts are included in Fuel, purchased power and direct transmission expense in the Consolidated Statements of Income and were approximately $286.7 million, $206.6 million and $222.5 million for the years ended December 31, 2021, 2020, and 2019, respectively. As of December 31, 2021, our commitments under these contracts were $283.2 million in 2022, $269.7 million in 2023, $221.8 million in 2024, $219.4 million in 2025, $172.2 million in 2026, and $1.5 billion thereafter. These commitments are not reflected in our Consolidated Financial Statements.

Hydroelectric License Commitments

With the 2014 purchase of hydroelectric generating facilities and associated assets located in Montana, we assumed two Memoranda of Understanding (MOUs) existing with state, federal and private entities. The MOUs are periodically updated and renewed and require us to implement plans to mitigate the impact of the projects on fish, wildlife and their habitats, and to increase recreational opportunities. The MOUs were created to maximize collaboration between the parties and enhance the possibility to receive matching funds from relevant federal agencies. Under these MOUs, we have a remaining commitment to spend approximately $26.7 million between 2022 and 2040. These commitments are not reflected in our Consolidated Financial Statements.

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 $24.1 million to $30.7 million. As of December 31, 2021, we had a reserve of approximately $26.9 million, which has not been discounted. Environmental costs are recorded when it is probable we are liable for the remediation and we can reasonably estimate the liability. We use a combination of site investigations and monitoring to formulate an estimate of environmental remediation costs for specific sites. Our monitoring procedures and development of actual remediation plans depend not only on site specific information but also on coordination with the different environmental regulatory agencies in our respective jurisdictions; therefore, while remediation exposure exists, it may be many years before costs are incurred.

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

The following summarizes the change in our environmental liability (in thousands):

	December 31,		
	2021	2020	2019
Liability at January 1,	$ 28,895	$ 30,276	$ 29,741
Deductions	(2,799)	(2,977)	(2,232)
Charged to costs and expense	770	1,596	2,767
Liability at December 31,	$ 26,866	$ 28,895	$ 30,276

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

Manufactured Gas Plants - Approximately $22.1 million of our environmental reserve accrual is related to the following manufactured gas plants.

South Dakota - A formerly operated manufactured gas plant located in Aberdeen, South Dakota, has been identified on the Federal Comprehensive Environmental Response, Compensation, and Liability Information System list as contaminated with coal tar residue. We are currently conducting feasibility studies, implementing remedial actions pursuant to work plans approved by the South Dakota Department of Agriculture and Natural Resources, and conducting ongoing monitoring and operation and maintenance activities. As of December 31, 2021, the reserve for remediation costs at this site was approximately $8.1 million, and we estimate that approximately $3.0 million of this amount will be incurred through 2025.

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

Montana - We own or have responsibility for sites in Butte, Missoula, and Helena, Montana on which former manufactured gas plants were located. The Butte and Helena sites, both listed as high priority sites on Montana's state superfund list, were placed into the Montana Department of Environmental Quality (MDEQ) voluntary remediation program for cleanup due to soil and groundwater impacts. Soil and coal tar were removed at the sites in accordance with the MDEQ requirements. Groundwater monitoring is conducted semiannually at both sites. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of additional remedial actions and/or investigations, if any, at the Butte site.

In August 2016, the MDEQ sent us a Notice of Potential Liability and Request for Remedial Action regarding the Helena site. In October 2019, we submitted a third revised Remedial Investigation Work Plan (RIWP) for the Helena site addressing MDEQ comments. The MDEQ approved the RIWP in March 2020 and we expect work at the Helena site to continue into 2022.

MDEQ has indicated it expects to proceed in listing the Missoula site as a Montana superfund site. After researching historical ownership, we have identified another potentially responsible party with whom we have entered into an agreement allocating third-party costs to be incurred in addressing the site. The other party has assumed the lead role at the site and has submitted a voluntary remediation plan for the Missoula site to MDEQ. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of risk-based remedial action, if any, at the Missoula site.

Global Climate Change - National and international actions have been initiated to address global climate change and the contribution of greenhouse gas (GHG) including, most significantly, carbon dioxide (CO_2). These actions include legislative proposals, Executive and Environmental Protection Agency (EPA) actions at the federal level, 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. In 2019, the EPA finalized the Affordable Clean Energy Rule (ACE), which repealed the 2015 Clean Power Plan (CPP) in regulating GHG emissions from coal-fired plants. The U.S. Court of Appeals for the District of Columbia Circuit issued an opinion on January 19, 2021, vacating the ACE and remanding it to EPA for further action. The United States Supreme Court agreed to review the case in October 2021 and oral argument regarding the scope of EPA's authority to regulate GHG emissions is scheduled to take place February 28, 2022, with a decision expected the following summer. It also is widely expected that the Biden Administration will develop an alternative plan for reducing GHG emissions from coal-fired plants, and in a memorandum dated February 12, 2021, EPA stated its belief that the January 19, 2021 opinion left neither the ACE nor the CPP rules in place.

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

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

Clean Air Act Rules and Associated Emission Control Equipment Expenditures - The EPA has proposed or issued a number of rules under different provisions of the Clean Air Act (CAA) that could require the installation of emission control equipment at the generation plants in which we have joint ownership. Air emissions at our thermal generating plants are managed by the use of emissions and combustion controls and monitoring, and sulfur dioxide allowances. These measures are anticipated to be sufficient to permit the facilities to continue to meet current air emissions compliance requirements.

Regional Haze Rules - In January 2017, the EPA published amendments to the requirements under the CAA for state plans for protection of visibility - regional haze rules. Among other things, these amendments revised the process and requirements for the state implementation plans and extended the due date for the next periodic comprehensive regional haze state implementation plan revisions from 2018 to 2021.

The states of Montana, North Dakota and South Dakota are expected to develop and submit to EPA, for its approval, their respective State Implementation Plans (SIP) for Regional Haze compliance. While these states, among others, did not meet the EPA's July 31, 2021 submission deadline, we still expect each state to submit its SIP in 2022. The draft Montana SIP does not require any additional controls at Colstrip Units 3 and 4. The draft North Dakota SIP does not require any additional controls at the Coyote generating facility, however the EPA, following a preliminary review, has asked North Dakota to reassess its determination regarding Coyote. The draft South Dakota SIP does not require any additional controls at the Big Stone generating facility. Until these SIPs are submitted and approved by EPA, the potential remains that installation of additional emissions controls might be required at these facilities.

Jointly Owned Plants - We have joint ownership in generation plants located in South Dakota, North Dakota, Iowa, and Montana that are or may become subject to the various regulations discussed above that have been or may be issued or proposed.

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

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

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

LEGAL PROCEEDINGS

Pacific Northwest Solar Litigation

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

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

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

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

In August 2017, 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 was reduced to approximately $8 million for the alleged breach of the four power purchase agreements. We participated in an unsuccessful mediation on January 24, 2019 and subsequent settlement efforts also have been unsuccessful.

On August 31, 2021, the Court ruled that the four agreements are valid and enforceable contracts and that NorthWestern 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 $0.4 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 judgement set aside. On February 9, 2022, the judge denied our post-trial motion. We have 30 days from February 9, 2022 to appeal the judgement to the Ninth Circuit Court of Appeals if we decide to do so. The plaintiff did not seek any post-trial relief and the deadline for doing so has passed.

State of Montana - Riverbed Rents

On April 1, 2016, the State of Montana (State) filed a complaint on remand (the State's Complaint) with the Montana First Judicial District Court (State District Court), naming us, along with Talen Montana, LLC (Talen) as defendants. The State claimed it owns the riverbeds underlying 10 of our, 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. The parties must submit amended findings of fact and conclusions of law, along with post-trial briefing, by April 29, 2022. A decision on navigability is expected following such submissions. Damages were bifurcated by agreement and will be tried separately, should the Federal District Court find any segments navigable.

We dispute the State's claims and intend 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 Montana Environmental Information Center against the owners and operator of Colstrip, the owners of Units 1 and 2 agreed to shut down those units no later than July 2022. In January 2020, the owners of Units 1 and 2 closed those two units. We do not have ownership in Units 1 and 2, and decisions regarding 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 expect to experience a negative impact on our transmission revenue due to reduced amounts of energy transmitted across our transmission lines. We expect to incorporate any reduction in revenue in our next general electric rate filing, resulting in lower revenue credits to certain customers.

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. As a result of the Washington legislation, four of the six joint owners of Units 3 and 4 requested the operator prepare a 2021 budget reflecting closure of Units 3 and 4 by 2025, and alternately a closure of Unit 3 by 2025 and a closure of Unit 4 by 2027. Differing viewpoints on closure dates delayed approval of the 2021 budget, until it was approved on March 22, 2021. Budgeting for 2022 was also delayed, with the same four joint owners demanding substantial budget reductions, but was ultimately approved on January 21, 2022. Such budgeting pressures may result in future budgets that may not be sufficient to maintain the reliability of Units 3 and 4.

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 Arbitration has given rise to three lawsuits concerning the number of arbitrators, the venue and the applicable arbitration laws. The four joint owners from the Pacific Northwest assert 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 Montana Senate Bill 265 (SB 265), which requires the Arbitration be conducted, with three arbitrators, in Montana and pursuant to the Montana Uniform Arbitration Act. The three initiated lawsuits do not make direct financial demands, and instead, are intended to address issues related to process for the 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 Montana, LLC, the operator of the Colstrip Steam Plant, 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 the Colstrip Steam Plant. 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 the Colstrip Steam Plant, 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.

Since this lawsuit is in its early stages, we are unable 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 the opinion of management, the amount of ultimate liability with respect to these other actions will not materially affect our financial position, results of operations, or cash flows.

(19) Revenue from Contracts with Customers

Accounting Policy

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

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

Nature of Goods and Services

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

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

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

Disaggregation of Revenue

The following tables disaggregate our revenue for the twelve months ended by major source and customer class (in millions):

December 31, 2021	Electric	Natural Gas	Total
Montana	334.6	126.0	460.6
South Dakota	65.4	26.6	92.0
Nebraska	—	21.0	21.0
Residential	**400.0**	**173.6**	**573.6**
Montana	356.7	64.7	421.4
South Dakota	102.5	19.1	121.6
Nebraska	—	11.4	11.4
Commercial	**459.2**	**95.2**	**554.4**
Industrial	37.9	1.1	39.0
Lighting, Governmental, Irrigation, and Interdepartmental	32.1	1.4	33.5
Total Customer Revenues	**929.2**	**271.3**	**1,200.5**
Other Tariff and Contract Based Revenues	89.5	36.8	126.3
Total Revenue from Contracts with Customers	**1,018.7**	**308.1**	**1,326.8**
Regulatory amortization	33.5	12.0	45.5
Total Revenues	**$ 1,052.2**	**$ 320.1**	**$ 1,372.3**

December 31, 2020	Electric	Natural Gas	Total
Montana	320.8	103.5	424.3
South Dakota	66.6	21.5	88.1
Nebraska	—	16.9	16.9
Residential	**387.4**	**141.9**	**529.3**
Montana	338.3	51.3	389.6
South Dakota	101.1	14.3	115.4
Nebraska	—	8.1	8.1
Commercial	**439.4**	**73.7**	**513.1**
Industrial	36.8	0.9	37.7
Lighting, Governmental, Irrigation, and Interdepartmental	31.8	0.9	32.7
Total Customer Revenues	**895.4**	**217.4**	**1,112.8**
Other Tariff and Contract Based Revenues	58.5	35.5	94.0
Total Revenue from Contracts with Customers	**953.9**	**252.9**	**1,206.8**
Regulatory amortization	(13.1)	5.0	(8.1)
Total Revenues	**$ 940.8**	**$ 257.9**	**$ 1,198.7**

December 31, 2019	Electric	Natural Gas	Total
Montana	308.8	109.4	418.2
South Dakota	62.5	25.8	88.3
Nebraska	—	20.2	20.2
Residential	**371.3**	**155.4**	**526.7**
Montana	348.1	55.7	403.8
South Dakota	97.1	19.3	116.4
Nebraska	—	10.5	10.5
Commercial	**445.2**	**85.5**	**530.7**
Industrial	43.6	1.0	44.6
Lighting, Governmental, Irrigation, and Interdepartmental	30.6	1.0	31.6
Total Customer Revenues	**890.7**	**242.9**	**1,133.6**
Other Tariff and Contract Based Revenues	61.7	35.8	97.5
Total Revenue from Contracts with Customers	**952.4**	**278.7**	**1,231.1**
Regulatory amortization	28.8	(2.0)	26.8
Total Revenues	**$ 981.2**	**$ 276.7**	**$ 1,257.9**

(20) Segment and Related 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 management for internal reporting purposes and involves estimates and assumptions.

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

December 31, 2021	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 1,052,182	$ 320,134	$ —	$ —	$ 1,372,316
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	294,820	130,728	—	—	425,548
Utility Margin	757,362	189,406	—	—	946,768
Operating and maintenance	156,383	51,920	—	—	208,303
Administrative and general	72,641	27,550	1,682	—	101,873
Property and other taxes	134,910	38,526	8	—	173,444
Depreciation and depletion	154,626	32,841	—	—	187,467
Operating income (loss)	238,802	38,569	(1,690)	—	275,681
Interest expense, net	(82,678)	(6,083)	(4,913)	—	(93,674)
Other income, net	3,676	3,046	1,530	—	8,252
Income tax (expense) benefit	(2,512)	(2,640)	1,733	—	(3,419)
Net income (loss)	$ 157,288	$ 32,892	$ (3,340)	$ —	$ 186,840
Total assets	$ 5,432,578	$ 1,342,031	$ 5,834	$ —	$ 6,780,443
Capital expenditures	$ 354,775	$ 79,553	$ —	$ —	$ 434,328

December 31, 2020	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 940,815	$ 257,855	$ —	$ —	$ 1,198,670
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	236,581	69,609	—	—	306,190
Utility margin	704,234	188,246	—	—	892,480
Operating and maintenance	149,220	53,771	—	—	202,991
Administrative and general	69,602	26,311	(1,789)	—	94,124
Property and other taxes	140,621	38,887	9	—	179,517
Depreciation and depletion	147,968	31,676	—	—	179,644
Operating income	196,823	37,601	1,780	—	236,204
Interest expense, net	(85,487)	(6,341)	(4,984)	—	(96,812)
Other income (expense), net	4,867	2,704	(2,718)	—	4,853
Income tax benefit (expense)	11,282	(2,426)	2,114	—	10,970
Net income (loss)	$ 127,485	$ 31,538	$ (3,808)	$ —	$ 155,215
Total assets[(1)]	$ 5,126,589	$ 1,251,240	$ 11,620	$ —	$ 6,389,449
Capital expenditures	$ 324,369	$ 81,393	$ —	$ —	$ 405,762

(1) Subsequent to the issuance of our Annual Report on Form 10-K for the year ended December 31, 2020, we determined that Total Assets - Electric and Total Assets - Gas had been incorrectly reported due to an error in the allocation methodology utilized to calculate assets by segment. As a result, the December 31, 2020 Total Assets - Electric and Total Assets - Gas amounts have been corrected from the amounts previously reported to reflect an increase of Total Assets - Electric and a decrease of Total Assets - Gas of $488.3 million. The correction had no impact on net income or the presentation of total assets on the consolidated balance sheets and was determined not to be material.

December 31, 2019	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 981,178	$ 276,732	$ —	$ —	$ 1,257,910
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	239,589	78,431	—	—	318,020
Utility margin	741,589	198,301	—	—	939,890
Operating and maintenance	155,285	53,767	—	—	209,052
Administrative and general	77,139	28,965	3,073	—	109,177
Property and other taxes	134,686	37,192	10	—	171,888
Depreciation and depletion	143,262	29,661	—	—	172,923
Operating income (loss)	231,217	48,716	(3,083)	—	276,850
Interest expense, net	(78,809)	(6,218)	(10,041)	—	(95,068)
Other (expense) income, net	(1,365)	(814)	2,592	—	413
Income tax (expense) benefit	(6,079)	493	25,511	—	19,925
Net income	$ 144,964	$ 42,177	$ 14,979	$ —	$ 202,120
Total assets	$ 4,808,011	$ 1,270,811	$ 4,664	$ —	$ 6,083,486
Capital expenditures	$ 241,190	$ 74,826	$ —	$ —	$ 316,016

(21) Fourth Quarter Financial Data (Unaudited)

Our fourth quarter financial information has not been audited, but, in management's opinion, includes all adjustments necessary for a fair presentation. Amounts presented are in thousands, except per share data:

	Three Months Ended December 31,	
	2021	2020
Operating revenues	$ 347,341	$ 313,445
Operating income	79,990	66,496
Net income	$ 51,336	$ 53,551
Average common shares outstanding	53,293	50,583
Income per average common share:		
Basic	$ 0.96	$ 1.06
Diluted	$ 0.96	$ 1.06

DESCRIPTION OF SECURITIES

The following description of the common stock of NorthWestern Corporation, a Delaware corporation is a summary of the general terms thereof and is qualified in its entirety by the provisions of our certificate of incorporation, as amended and restated (the "certificate of incorporation"), and bylaws, as amended and restated (the "bylaws"), copies of both of which have been filed as exhibits to our most recent Annual Report on Form 10-K filed with the Securities and Exchange Commission, and the laws of the state of Delaware.

Our certificate of incorporation authorizes us to issue 250,000,000 shares of stock, divided into two classes: (1) 200,000,000 shares of common stock, $0.01 par value per share, and (2) 50,000,000 shares of preferred stock, $0.01 par value per share. Our common stock is our only security registered under Section 12 of the Securities Exchange Act of 1934.

As of February 4, 2022, we had no preferred stock outstanding. However, our board of directors is authorized, subject to any limitations imposed by law, without the approval of our stockholders, to issue from time to time up to a total of 50,000,000 shares of our preferred stock, $0.01 par value per share, in one or more series, with each such series having such powers, including voting powers, preferences, and relative participating optional or other special rights and any qualifications, limitations or restrictions thereof, as our board of directors may determine at the time of issuance. Thus, without seeking stockholder approval, our board may issue preferred stock with voting and other rights that could adversely affect the voting power of the holders of our common stock.

The issuance of our preferred stock, while potentially providing us with flexibility in connection with possible acquisitions and other corporate purposes, could have the effect of making it more difficult for a third party to acquire, or delay or deter a third party from attempting to acquire, a majority of our outstanding voting stock.

Dividend Rights

Subject only to any prior rights and preferences of any shares of our preferred stock that may in the future be issued and outstanding, the holders of our common stock are entitled to receive dividends when, as and if declared by our board of directors out of legally available funds. There can be no assurance that funds will be legally available to pay dividends at any given time or that, if funds are available, the board of directors will declare a dividend.

Voting Rights

The holders of our common stock are entitled to one vote per share on all matters to be voted on by stockholders. Under our certificate of incorporation, the voting rights, if any, of our preferred stock may differ from the voting rights of our common stock. The holders of our common stock do not have cumulative voting rights. Our bylaws provide for a plurality voting standard for the election of directors.

Liquidation Rights

If we were to liquidate, subject to the terms of any outstanding series of preferred stock, the holders of our common stock are entitled to receive pro rata our assets legally available for distribution to stockholders.

Other Rights

Our common stock is not liable to further calls or assessment. The holders of our common stock have no preemptive rights. Our common stock cannot be redeemed, and it does not have any conversion rights or sinking fund provisions.

Effects on Our Common Stock if We Issue Preferred Stock

As discussed above, our board of directors has the authority, without further action by the stockholders, to issue up to 50,000,000 shares of preferred stock in one or more series. If we issue any preferred stock, it may negatively affect the holders of our common stock. These possible negative effects include diluting the voting power of shares of our common stock and affecting the market price of our common stock. In addition, the ability of our board of directors to issue preferred stock may delay or prevent a change in control of NorthWestern Corporation.

Provisions of our Certificate of Incorporation and our Bylaws That Could Delay or Prevent a Change in Control

Our certificate of incorporation and bylaws contain provisions which will make it difficult to obtain control of NorthWestern Corporation if our board of directors does not approve the transaction. The provisions include the following:

Number of Directors, Vacancies, Removal of Directors

Our bylaws provide that our board of directors will have at least five and at most 11 directors. A majority of the continuing directors decide the exact number of directors at a given time and fill any new directorships and vacancies.

Our certificate of incorporation and bylaws provide that our directors may be removed, with or without cause, by a majority of the shares then entitled to vote in an election of directors. In addition, our certificate of incorporation provides that any action required or permitted to be taken by our stockholders, including the removal of directors, must be effected at a duly called annual or special meeting of stockholders and may not be effected by any consent in writing by such stockholders. Our bylaws permit stockholders to call a special meeting if called by 25% or more of the outstanding shares of voting capital stock of the company.

No Cumulative Voting. Our certificate of incorporation does not provide for cumulative voting.

Advance Notice Provisions. Our bylaws require that for a stockholder to nominate a director or bring other business before an annual meeting, the stockholder must give written notice not later than 90 days nor earlier than 120 days prior to the first anniversary of the preceding year's annual meeting. However, if the annual meeting is more than 30 days before or more than 70 days after such anniversary date, the stockholder must give notice not earlier than 120 days prior to such annual meeting, nor later than the later of 90 days prior to such annual meeting or 10 days after the day on which the public announcement of the date of the meeting was first made. In addition, if the number of directors to be elected to the board at an annual meeting is increased and there is no public announcement naming the nominees for the additional directorships at least 100 days prior to the first anniversary of the preceding year's annual meeting, a stockholder must give notice, but only with respect to nominees for the additional directorships, so it is delivered not later than 10 days after the day on which such public announcement is first made.

All such notices must be received by our Corporate Secretary by the close of business on the specified date to be deemed to have been delivered on that date. The public announcement of an adjournment or postponement of an annual meeting does not commence a new time period or extend the foregoing time period.

No Stockholder Action by Written Consent. Our certificate of incorporation and bylaws provide that all action by stockholders must be taken at an annual or special meeting. The stockholders may not act by written consent. This provision prevents our stockholders from initiating or effecting any action by written consent, thereby limiting the ability of our stockholders to take actions opposed by our board of directors.

Special Meetings of Stockholders. Our bylaws provide that special meetings of stockholders may be called by the chairman of the board of directors, the board of directors acting pursuant to a resolution adopted by a majority of the whole board of directors, or upon written notice to the board of directors by holders of 25% or more of our outstanding voting stock.

Provisions Relating to the Authorization of Business Combinations. Our certificate of incorporation requires that certain mergers, consolidations, sales or other dispositions of substantial assets, issuances of company securities and certain other Business Combinations involving us and any Interested Stockholder of our voting stock be approved by a majority of our Disinterested Directors or by the holders of at least 66 2/3% of the outstanding shares of capital stock of the company entitled to vote generally, excluding any shares beneficially owned by the Interested Stockholder or any Affiliate of any Interested Stockholder (as such terms are defined in the certificate of incorporation). This provision may be amended only by the approval of the holders of at least two-thirds of the outstanding shares of our voting stock.

Provisions of Delaware Law That Could Delay or Prevent a Change in Control

We are subject to the provisions of Section 203 of the Delaware General Corporation Law. In general, this law prohibits us from engaging in any "business combination" with any interested stockholder for a three-year period after such interested stockholder acquires the stock, unless:

- prior to the time that the person became an interested stockholder, the board of directors of the corporation approved either the business combination or the transaction which resulted in the stockholder becoming an interested stockholder;

- upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of the voting stock of the corporation outstanding at the time the transaction commenced, excluding for the purpose of determining the number of shares outstanding (but not the outstanding voting stock owned by the interested stockholder) those shares owned by (i) the corporation's officers and directors and (ii) employee stock plans in which employee participants do not have the right to determine confidentially whether shares held subject to the plan will be tendered in a tender or exchange offer; or

- at or subsequent to the time the business combination is approved by the corporation's board of directors and authorized at an annual or special meeting of its stockholders, and not by written consent, by the affirmative vote of at least 66-2/3% of its outstanding voting stock that is not owned by the interested stockholder.

The term "business combination" is broadly defined to include mergers, consolidations, and sales and other dispositions of assets having an aggregate market value equal to 10% or more of the consolidated assets of the corporation, and other specified transactions resulting in financial benefits to the interested stockholder. An "interested stockholder" is a person who, together with affiliates and associates, owns (or within three years did own) 15% or more of the corporation's voting stock.

The restrictions on business combinations with interested stockholders contained in Section 203 of the Delaware General Corporation Law do not apply to a corporation whose certificate of incorporation or bylaws contains a provision expressly electing not to be governed by the statute. Neither our certificate of incorporation nor our bylaws contains a provision electing to "opt-out" of Section 203. Section 203 of the Delaware General Corporation Law could prohibit or delay mergers or other takeover or change in control attempts and, accordingly, may discourage attempts to acquire us.

Listing

Our common stock is listed on the Nasdaq Stock Market LLC.

Transfer Agent and Registrar

The transfer agent and registrar for our capital stock is Computershare, Inc., Providence, Rhode Island.

Exhibit 21

SUBSIDIARIES OF THE REGISTRANT

Name	State of Jurisdiction of Incorporation or Limited Partnership
The Clark Fork and Blackfoot, L.L.C.	Montana
NorthWestern Services, LLC	Delaware
Canadian-Montana Pipe Line Corporation	Canada
Risk Partners Assurance, Ltd.	Bermuda
Lodge Creek Pipelines, LLC	Nevada
Willow Creek Gathering, LLC	Nevada
Havre Pipeline Company, LLC	Texas
NorthWestern Energy Solutions, Inc.	Delaware

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-122428, 333-124624, 333-149388, 333-158731, 333-175813, and 333-197627 on Form S-8 and Registration Statement Nos. 333-253047, and 333-257950 on Form S-3 of our reports dated February 10, 2022, relating to the financial statements of NorthWestern Corporation (the “Company”) and the effectiveness of the Company’s internal control over financial reporting appearing in this Annual Report on Form 10-K for the year ended December 31, 2021.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 10, 2022

EXHIBIT 31.1

CERTIFICATION

I, Robert C. Rowe, certify that:

1. I have reviewed this annual report on Form 10-K of NorthWestern Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 11, 2022

/s/ ROBERT C. ROWE

Robert C. Rowe

Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Crystal D. Lail, certify that:

1. I have reviewed this annual report on Form 10-K of NorthWestern Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 11, 2022

/s/ CRYSTAL D. LAIL

Crystal D. Lail

Vice President and Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of NorthWestern Corporation (the "Company") on Form 10-K for the period ended December 31, 2021, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Robert C. Rowe, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

1) The Report fully complies with the requirements of Sections 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 11, 2022

/s/ ROBERT C. ROWE

Robert C. Rowe
Chief Executive Officer

Exhibit 32.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of NorthWestern Corporation (the “Company”) on Form 10-K for the period ended December 31, 2021, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Crystal D. Lail, Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

1) The Report fully complies with the requirements of Sections 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 11, 2022

/s/ CRYSTAL D. LAIL

Crystal D. Lail

Vice President and Chief Financial Officer