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, 2024
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 No. 333-212006

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.
(Exact name of registrant as specified in its charter)

Colorado	**84-0464189**
(State or other jurisdiction of incorporation or organization)	(I.R.S. employer identification number)
1100 West 116th Avenue	
Westminster , Colorado	**80234**
(Address of principal executive offices)	(Zip Code)

(303) 452-6111
(Registrant's telephone number, including area code)

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
None	None	None

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 (Note: The registrant is not subject to the filing requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934 (the "Exchange Act"), but voluntarily files reports with the Securities and Exchange Commission).

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

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

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

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

Indicate by check mark whether the registrant 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 accounting firm that prepared or issued its audit report. ☐

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant: **NONE.**

Indicate the number of shares outstanding of each of the registrant's classes of common stock. **The registrant is a membership corporation and has no authorized or outstanding equity securities.**

Documents incorporated by reference: **NONE.**

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

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GLOSSARY

The following abbreviations and acronyms used in this annual report on Form 10-K are defined below:

Abbreviations or Acronyms	Definition
2022 Revolving Credit Agreement	Amended and Restated Credit Agreement, dated as of April 25, 2022, between us and CFC, as administrative agent, as amended
2023 ERP	our 2023 Electric Resource Plan filed with the COPUC
AQCC	Colorado Air Quality Control Commission
Basin	Basin Electric Power Cooperative
Basin Eastern WPC	Amended and Restated Wholesale Power Contract for the Eastern Interconnection, between us and Basin
Board	Board of Directors
BYOR	Bring Your Own Resource
CAISO	California Independent System Operator
CERCLA, or Superfund	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CFC	National Rural Utilities Cooperative Finance Corporation
Clean Water Act	Federal Water Pollution Control Act, as amended
CO_2	carbon dioxide
CoBank	CoBank, ACB
Colowyo Coal	Colowyo Coal Company L.P., a subsidiary of ours
COPUC	Colorado Public Utilities Commission
Corps	U.S. Army Corps of Engineers
Craig Station	Craig Generating Station
D.C. Circuit Court of Appeals	U.S. Court of Appeals for the District of Columbia Circuit
DM/NFR	Denver Metropolitan/North Front Range
DSR	Debt Service Ratio (as defined in our Master Indenture)
ECR	Equity to Capitalization Ratio (as defined in our Master Indenture)
Elk Ridge	Elk Ridge Mining and Reclamation, LLC, a subsidiary of ours
EMS	Environmental Management System
EPA	Environmental Protection Agency
ESA	Endangered Species Act
Escalante Station	Escalante Generating Station
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings Inc.
FPA	Federal Power Act, as amended
GAAP	accounting principles generally accepted in the United States
IRA	Inflation Reduction Act of 2022
IRS	Internal Revenue Service
kWh	kilowatt hour
LAP	Loveland Area Projects
LIBOR	London Interbank Offered Rate
LPEA	La Plata Electric Association, Inc.
MACT	maximum achievable control technology
Master Indenture	Master First Mortgage Indenture, Deed of Trust and Security Agreement, dated effective as of December 15, 1999, between us and U.S. Bank Trust Company, National Association, as successor trustee
MBPP	Missouri Basin Power Project
Members	our Utility Members and Non-Utility Members

Moody’s	Moody’s Investors Services, Inc.
MPEI	Mountain Parks Electric, Inc.
MRO	Midwestern Reliability Organization
MW	megawatt
MWh	megawatt hour
NAAQS	National Ambient Air Quality Standard
NERC	North American Electric Reliability Corporation
New ERA Program	USDA's Empowering Rural America Program
Non-Utility Members	our non-utility members
NO_X	nitrogen oxide
NPDES	National Pollutant Discharge Elimination System
NRECA	National Rural Electric Cooperative Association
NRPPD	Northwest Rural Public Power District
OATT	Open Access Transmission Tariff
PCB	polychlorinated biphenyl
PFAS	per- and polyfluoroalkyl substances
PNM	Public Service Company of New Mexico
ppb	parts per billion
PSCO	Public Service Company of Colorado
PURPA	Public Utility Regulatory Policies Act of 1978, as amended
RES	Renewable Energy Standard
RPS	Renewable Portfolio Standard
RS Plan	National Rural Electric Cooperative Association Retirement Security Plan
RUS	Rural Utilities Service
S&P	S & P Global Ratings
Salt River Project	Salt River Project Agricultural Improvement and Power District
SEC	Securities and Exchange Commission
SIP	State Implementation Plan
SLCAIP	Salt Lake City Area/Integrated Projects
SO_2	sulfur dioxide
SPP	Southwest Power Pool, Inc.
Springerville Partnership	Springerville Unit 3 Partnership LP, a subsidiary of ours
Springerville Unit 3	Springerville Generating Station Unit 3
TEP	Tucson Electric Power Company
Term SOFR	the implied rate on the future movement in the Secured Overnight Financing Rate (or “SOFR") over a future reference period
Tri-State, We, Our, Us, the Association	Tri-State Generation and Transmission Association, Inc.
United Power	United Power, Inc.
USDA	United States Department of Agriculture
USFWS	U.S. Fish and Wildlife Service
Utility Members	our electric distribution member systems, consisting of both Class A members and Class B members
WACM	Western Area Colorado Missouri
WAPA	Western Area Power Administration (a power marketing agency of the U.S. Department of Energy)
WECC	Western Electricity Coordinating Council
WOTUS	Waters of the United States
Yampa Project	Craig Station Units 1 and 2 and related common facilities

FORWARD-LOOKING STATEMENTS

This annual report on Form 10-K contains “forward–looking statements.” All statements, other than statements of historical facts, that address activities, events or developments that we expect or anticipate to occur in the future, including matters such as the timing of various regulatory and other actions, future capital expenditures, future resources and generation portfolio, future use of deferred revenue, business strategy, member withdrawals, and development, construction, operation, or closure of facilities (often, but not always, identified through the use of words or phrases such as “will likely result,” “is expected to,” “planned,” “will continue,” “is anticipated,” “estimated,” “forecasted,” “projection,” “target” and “outlook”) are forward–looking statements.

Although we believe that in making these forward–looking statements our expectations are based on reasonable assumptions, any forward–looking statement involves uncertainties and there are important factors that could cause actual results to differ materially from those expressed or implied by these forward–looking statements.

PART I

ITEM 1. BUSINESS

OVERVIEW

Our Business

Tri–State Generation and Transmission Association, Inc. is a taxable wholesale electric power generation and transmission cooperative operating on a not–for–profit basis. We were incorporated under the laws of the State of Colorado in 1952 as a cooperative corporation. We were formed by our Utility Members for the purpose of providing wholesale power and transmission services to our Utility Members for their resale of the power to their retail consumers. Our Utility Members serve large portions of Colorado, Nebraska, New Mexico and Wyoming. We currently have forty Utility Members after the withdrawal of United Power in May 2024 and MPEI in February 2025 from membership in us.

We are owned entirely by our forty-three Members. Thirty-six of our Members are not-for-profit, electric distribution cooperative associations. Four Members are public power districts, which are political subdivisions of the State of Nebraska. We also have three Non-Utility Members. The retail service territories of our Utility Members cover approximately 182,000 square miles and their customers include suburban and rural residences, farms and ranches, and large and small businesses and industries. Our Utility Members serve approximately 522,000 retail electric meters. Our Utility Members are the sole state-certified providers of electric service to retail (residential and business) customers within their designated service territories.

Our principal executive offices are located at 1100 West 116th Avenue, Westminster, Colorado 80234. Our telephone number is (303) 452-6111. Our website is www.tristate.coop. Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports are made available on our website as soon as reasonably practicable after the material is filed with the SEC. Information contained on our website is not incorporated by reference into and should not be considered to be part of this annual report.

Cooperative Structure

A cooperative is a business entity owned by its members. As organizations acting on a not-for-profit basis, cooperatives provide or purchase property, products or services to their members on a cost-effective basis, in part by eliminating the need to produce profits or a return on equity in excess of required margins. Cooperatives generally establish rates to recover their costs and to collect a portion of revenues in excess of expenses, which constitute margins. Margins not yet distributed to members in cash constitute patronage capital, a cooperative's principal source of equity. Patronage capital is held for the account of the members without interest and returned when the board of directors deems it appropriate to do so. The timing and amount of any actual return of capital to the members depends on the financial goals of the cooperative, current and projected capital expenditures, and the cooperative's loan and security agreements.

Electric distribution cooperatives form generation and transmission cooperatives, such as us, to acquire power supply resources, typically through the construction of facilities or the development of other power purchase arrangements, at a lower cost than if they were acquiring those resources alone. Electric cooperatives usually have no equity securities or stock.

FERC Jurisdictional

On September 3, 2019, we became regulated as a public utility under Part II of the FPA when we admitted a Non-Utility Member, MIECO, Inc. (a non-governmental/non-electric cooperative entity), as a new Member/owner.

In September 2021, we filed as a rate schedule with FERC our modified contract termination payment methodology associated with a Utility Member terminating its wholesale electric service contract with us. FERC accepted our modified contract termination payment methodology, subject to refund. In December 2023, FERC issued an order adopting a modified balance sheet approach for the contract termination payment methodology. In February 2025, we filed our fourth compliance filing with a revised rate schedule with FERC based upon FERC's December 2024 order on our latest compliance filings.

In May 2024, United Power withdrew from membership in us and terminated its wholesale electric service contract pursuant to its April 2022 non-conditional notice of intent to withdraw. In February 2025, MPEI withdrew from membership in us and terminated its wholesale electric service contract pursuant to its January 2023 non-conditional notice of intent to withdraw. LPEA provided us a non-conditional notice of intent to withdraw in March 2024, with an April 1, 2026, withdrawal effective date. NRPPD did not comply with the rate schedule arising out of its April 2022 non-conditional notice of intent to withdraw and made no contract termination payment to us and thus remains a Class A member of us. NRPPD provided us a second non-conditional notice of intent to withdraw in December 2024, with a January 1, 2027, withdrawal effective date. See "— MEMBERS – Contract Termination Payment and Relationship with Members."

In May 2024, we filed with FERC a request to adopt a new Class A wholesale rate schedule (A-41) for electric power sales to our Utility Members. The wholesale rate maintains our postage stamp rate, with the same rate components for all our Utility Members, and incorporated a new formulary rate, which can be adjusted annually based on the budgets approved by our Board, including an annual true-up mechanism. In July 2024, FERC issued an order accepting our A-41 wholesale rate schedule, effective August 1, 2024, subject to refund. FERC further set our rate filing for settlement and hearing procedures. See " — RATE REGULATION."

New ERA Program

In September 2023, we submitted a Letter of Interest to apply for a funding award of low-cost loans and grants through the New ERA Program, a $9.7 billion USDA program that is funded by the IRA. Our portfolio proposed in our Letter of Interest was the result of resource and financial modeling performed in connection with our preferred IRA scenario as part of Phase I of our 2023 ERP. In March 2024, we received an Invitation to Proceed from the USDA to complete the New ERA Program Application, and in June 2024, we submitted our Application. We have signed award commitment letters from USDA for $679 million in budget authority to fund approximately $2.49 billion of new electric generation and refinancing projects to enhance the reliability and affordability of our system. The vast majority of our award is in low-interest loans that will be repaid to the United States.

We believe that once funds from our New ERA Program award are dispersed that the New ERA Program award will allow us to promote rural economic growth and domestic energy development. Our existing and future resource mix, as outlined in our 2023 ERP, reflects an all-of-the-above strategy that ensures reliable power for our rural consumers by capitalizing on the abundant natural resources in the western region. We plan to use the New ERA award to invest in new generation and lessens the financial burden of stranded assets. The release of the funding from the USDA is subject to the availability of the funds and the impact of potential government action on the availability as well as the satisfaction of certain conditions, including execution of a loan/grant agreement and applicable security agreement, development and/or implementation of program regarding community support and engagement, where applicable, environmental approvals dependent on the type of project, and submittal of certain information, documents and certifications dependent on the type of project.

Power Supply and Transmission

We supply and transmit our Utility Members' electric power requirements through a portfolio of resources, including generation and transmission facilities, long-term purchase contracts and short-term energy purchases. We own, lease, have undivided percentage interests in, or have long-term purchase contracts with respect to various generating facilities. As of December 31, 2024, our diverse generation portfolio provides us with maximum available power of 4,661 MWs and is summarized in the table below:

Generation Portfolio (as of December 31, 2024)	Capacity (MW)	Percentage (%)
Renewables-contracts, including WAPA	1,698	36
Coal-fired base load facilities	1,550	33
Gas/oil-fired facilities	822	18
Other contracts, including Basin	591	13

We have three solar-based power purchase contracts totaling 340 MWs for facilities that achieved commercial operation in 2024. In the first half of 2024, we executed asset purchase agreements, along with engineering, procurement and construction contracts, for two solar-based facilities totaling 255 MWs that are expected to achieve commercial operation in 2025.

In December 2023, we filed Phase I of our 2023 ERP with the COPUC. In June 2024, we filed a settlement agreement for Phase I of our 2023 ERP that forecasted the need for approximately 1,500 MWs of new resources during the resource acquisition period of 2026-2031, the early retirement of Craig Station by September 2028, and, if we are awarded federal funding and reach agreements with the applicable parties, the early retirement of Springerville Unit 3 in 2031. In September 2024, as part of Phase II of our 2023 ERP, we issued three requests for proposals seeking bids for new dispatchable, renewable, and storage resources for the resource acquisition period of 2026-2031. See "— POWER SUPPLY RESOURCES" and "PROPERTIES" for a description of our long-term purchase contracts and our generating facilities, including retirements of our generating facilities, and our resource plan.

After the retirement of Craig Station and the addition of new resources, as of December 31, 2030, based upon Phase I of our 2023 ERP, our generation portfolio could be as set forth below. However, Phase II of our 2023 ERP is on-going and the results of Phase II is expected to change our anticipated generation portfolio as of December 31, 2029.

Potential Generation Portfolio (as of December 31, 2030) (1)	Capacity (MW)	Percentage (%)
Renewables, including WAPA	2,701	49
Gas/oil-fired facilities	1,112	20
Coal-fired base load facilities	902	16
Other contracts, including Basin	608	11
Energy storage	210	4

(1) 600 MWs of renewables, 290 MWs of natural gas-fired, and 210 MWs of energy storage resources needed through 2030, based upon Phase I of our 2023 ERP.

In addition to our diverse generation portfolio, as permitted by our wholesale electric service contracts with our Utility Members, as of December 31, 2024, our Utility Members own or control through long-term purchase power contracts approximately 89 MWs of operating distributed or renewable capacity that is used to deliver energy to our Utility Members' customers.

We transmit power to our Utility Members through resources that we own, lease or have undivided percentage interests in, or by wheeling power across lines owned by other transmission providers. As of December 31, 2024, we had ownership or capacity interests in approximately 5,819 miles of transmission lines and own or have major equipment ownership in 407 substations and switchyards. See "PROPERTIES" for a description of our transmission facilities.

Human Capital Resources

Employees are our most valuable resource and we endeavor to attract, develop, motivate and retain a diverse workforce and to develop, implement and support policies and programs that assist in this effort. We encourage superior performance by recognition and reward for employee ability and performance. As a cooperative, we do not have publicly traded stock and as a result do not have equity-based compensation programs. We compensate our employees through use of a total rewards package that includes base salary or hourly wages, retirement benefits, and health and welfare programs. Base salary and hourly wages are based upon performance and national salary data provided by various surveys, which include data from the labor market for positions with similar responsibilities.

We are committed to helping employees grow by offering training and development opportunities that support their progress. We encourage life-long learning and support this through on-the-job training, tuition reimbursement, apprenticeships and summer internships. We are also committed to the Cooperative Principle of Commitment to Community and provide opportunities for employees to contribute to various community programs and events as well as offer a paid volunteer day-off for employees to give back in their own communities.

We are committed to providing a respectful, safe and welcoming workplace where all employees' unique ideas and experiences are recognized. We facilitate this environment through open, honest communication and compliance with our Ethical Conduct and Conflict of Interest program.

Safety is one of our core values. We attend to the safety of our employees, our contractors, and our communities before all other priorities. We strive to emphasize that safety is everyone's responsibility, regardless of job or work location. We aspire to prevent all fatalities and serious injuries. We put the protection of human life and the prevention of injuries above all else. We believe injuries and illnesses are preventable and have committed to supporting our employees with the tools, knowledge, and empowerment to complete their work safely and successfully. We regularly review and update our safety and health programs and safety management systems and implement actions with the goal of continually improving our safety and health performance. We have established an Executive Safety Council to review new initiatives, ideas, and protocols, encourage the sharing of safety moments at all organized meetings with five or more employees, and constantly work to educate all employees on the importance of safety.

Our average employee tenure across our organization was 10 years. In 2024, our turnover was 14.87 percent, an increase from 10.13 percent in 2023. Retirements accounted for 2.4 percent of the turnover.

Including our subsidiaries, as of December 31, 2024, we employed 1,092 people, of which 174 were subject to collective bargaining agreements. As of December 31, 2024, none of these collective bargaining agreements will expire within one year. Since 2016, our number of employees has decreased by approximately 31 percent due to the closure of certain facilities, cost reduction efforts and other factors. We expect the number of employees to further decrease materially by 2028 with the closure of additional facilities by 2028. We supplement our workforce as needed through use of contingent workers.

MEMBERS

General

We have three classes of membership: Class A - utility full requirements members, Class B - utility partial requirements members, and Non-Utility Members. We currently have no Class B members, and therefore all our Utility Members are currently Class A members. Our Utility Members provide electric services, consisting of power supply and distribution services, to residential, commercial, industrial and agricultural customers primarily in Colorado, Nebraska, New Mexico and Wyoming. Our Utility Members' businesses involve the operation of substations, transformers and electric lines that deliver power to their customers. We currently have forty Utility Members. Our Utility Members and the states within which they primarily provide electric service are as follows:

Colorado:	
Empire Electric Association, Inc.	San Isabel Electric Association, Inc.
Gunnison County Electric Association	San Luis Valley Rural Electric Cooperative, Inc.
Highline Electric Association	San Miguel Power Association, Inc.
K.C. Electric Association	Sangre de Cristo Electric Association, Inc.
La Plata Electric Association, Inc.	Southeast Colorado Power Association
Morgan County Rural Electric Association	White River Electric Association, Inc.
Mountain View Electric Association, Inc.	Y-W Electric Association, Inc.
Poudre Valley Rural Electric Association, Inc.	

Nebraska:	
Chimney Rock Public Power District	Panhandle Rural Electric Membership Association
The Midwest Electric Cooperative Corporation	Roosevelt Public Power District
Northwest Rural Public Power District	Wheat Belt Public Power District

New Mexico:	
Central New Mexico Electric Cooperative, Inc.	Otero County Electric Cooperative, Inc.
Columbus Electric Cooperative, Inc.	Sierra Electric Cooperative, Inc.
Continental Divide Electric Cooperative, Inc.	Socorro Electric Cooperative, Inc.
Jemez Mountains Electric Cooperative, Inc.	Southwestern Electric Cooperative, Inc.
Mora-San Miguel Electric Cooperative, Inc.	Springer Electric Cooperative, Inc.
Northern Rio Arriba Electric Cooperative, Inc.	

Wyoming:	
Big Horn Rural Electric Company	High West Energy, Inc.
Carbon Power & Light, Inc.	Niobrara Electric Association, Inc.
Garland Light & Power Company	Wheatland Rural Electric Association
High Plains Power, Inc.	Wyrulec Company

We also currently have three Non-Utility Members: Ellgen Ranch Company, MIECO, Inc., and Olson's Greenhouses of Colorado, LLC. Ellgen Ranch Company is located in Colorado and is a party to ranch leases with Colowyo Coal. MIECO, Inc. is a California-based company that markets natural gas nationwide and is a major supplier of gas to our natural gas-fired generating facilities. Olson’s Greenhouses of Colorado, LLC is headquartered in Utah and conducts business in Colorado. Olson’s Greenhouses of Colorado, LLC has a contract to purchase thermal energy from us and reuses the waste steam that is generated from the J.M. Shafer Generating Station to heat its greenhouses.

Bylaws and Classes of Membership

Our Bylaws require each Utility Member, unless otherwise specified in a written agreement or the terms of our Bylaws, to purchase from us electric power and energy as provided in the Utility Member's contract with us. This contract is the wholesale electric service contract with each Utility Member, which is an all-requirements contract. Each wholesale electric service contract obligates us to sell and deliver to the Utility Member, and obligates the Utility Member to purchase and receive from us, all energy and capacity required for the operation of the Utility Member's system, as further modified by programs set out in tariffs filed with FERC. See "— Wholesale Electric Service Contracts (Full Requirements) - Class A members" and "— Bring Your Own Resource Program" for additional discussion regarding these programs.

Our Bylaws allow our Board to establish one or more classes of membership in addition to the all-requirements class of membership. However, the representation on our Board of any additional classes of membership would be determined by a vote of the Members at a membership meeting. Our Board established a non-utility membership class and authorized entering into membership agreements with Non-Utility Members. Non-Utility Members, as set forth in the membership agreements with such Non-Utility Members, have a right to vote at membership meetings, have rights to patronage capital, and have rights to liquidation proceeds, but have waived and have no right to representation on our Board. The non-utility membership class is intended to consist of entities that do not purchase power and energy from us and do not operate electric distribution systems. Our Bylaws limit the number of Non-Utility Members to no greater than ten. We currently have three Non-Utility Members. We may add new members in the future.

Our Board also established the Class B - utility partial requirements membership class and named the existing all requirements membership class the Class A - utility full requirements members. Both classes of membership are full-requirements transmission members. We currently have 40 Class A members and no Class B members. Class B members have representation on our Board if such Class B member purchases at least 65 percent of capacity from us.

Pursuant to our Bylaws, a Member may only withdraw from membership in us upon compliance with such equitable terms and conditions as our Board may prescribe, provided, however, that no Member shall be permitted to withdraw until it has met all its contractual obligations to us. See "— Contract Termination Payment and Relationship with Members." for additional discussion regarding Member withdrawals.

Wholesale Electric Service Contracts (Full Requirements) - Class A members

Our revenues are derived primarily from the sale of wholesale electric service to our Utility Members pursuant to long-term wholesale electric service contracts. These substantially similar contracts with our forty Utility Members extend through 2050. The wholesale electric service contracts are subject to automatic extension thereafter until either party provides at least two years’ notice of its intent to terminate. Each contract obligates us to sell and deliver to the Utility Member, and obligates the Utility Member to purchase and receive from us, all energy and capacity required for the operation of its system, except for sources such as photovoltaic cells, fuel cells, or others that are not connected to such Utility Member’s distribution or transmission system, and as further modified by programs set out in tariffs filed with FERC. Each Utility Member may elect to provide up to 5 percent of its requirements from distributed or renewable generation owned or controlled by the Utility Member and the Utility Member may also propose projects that it will own or control under our BYOR Program, subject to certain capacity limitations within that program. As of December 31, 2024, 21 Utility Members have enrolled in this 5 percent self-supply provision with capacity totaling approximately 94 MWs, of which 89 MWs are in operation.

Our Utility Members’ demand for energy is influenced by seasonal weather conditions. Historically, our peak load conditions have occurred during the months of June through August, when irrigation load is the highest. Our summer peak load conditions depend on summer temperatures and the amount of precipitation during the growing season (generally May through September). Relatively higher summer or lower winter temperatures tend to increase the demand and usage of electricity for heating, air conditioning and irrigation. Mild weather generally reduces the demand and usage of electricity because heating, air conditioning and irrigation systems are operated less frequently.

The table below shows our Utility Members’ aggregate coincident peak demand for the years 2020 through 2024 and the amount of energy that we supplied them. Our Utility Members’ 2024 peak demand decreased 16.4 percent compared to

2023 and the annual amount of energy we sold to our Utility Members in 2024 decreased 9.5 percent compared to 2023, primarily related to United Power's withdrawal on May 1, 2024.

Year	Utility Members' Peak Demand (MW) (1)	Amount of Energy Sold (MWh) (1)
2024	2,533	14,959,159
2023	3,030	16,530,385
2022	3,071	16,525,315
2021	2,974	15,676,830
2020	2,896	15,884,777

(1) Includes peak demand of and energy sales to Delta-Montrose Electric Association through June 30, 2020 and United Power through April 30, 2024.

Subject to certain force majeure conditions, we are required under the wholesale electric service contracts to use reasonable diligence to provide a constant and uninterrupted supply of electric service to our Utility Members. If our generation and other sources of supply are inadequate to serve all of our Utility Members' demand and we are unable to secure additional sources of supply, we are permitted to interrupt service to our Utility Members in accordance with a written policy established by our Board. We are currently able to provide all the requirements of our Utility Members and expect to continue to do so.

The wholesale electric service contracts we have with our Utility Members provide that our Utility Members shall pay us for electric service at rates and on the terms and conditions established by our Board at levels sufficient to produce revenues, together with revenues from all other sources, to meet our cost of operation, including reasonable reserves, debt and lease service, and development of our equity. Revenues from wholesale electric power sales to our Utility Members are primarily from our Class A wholesale rate schedule established by our Board, but such rate schedules are subject to FERC acceptance or approval. See "— RATE REGULATION." Revenue from one Utility Member, Poudre Valley Rural Electric Association, comprised 10.3 percent of our Utility Member revenue and 7.0 percent of our operating revenue in 2024. No other Utility Member exceeded 10 percent of our Utility Member revenue or our operating revenue in 2024. Our Utility Members are obligated to pay us monthly for the power, energy and transmission service we supply to them. Payments due to us under the wholesale electric service contracts are pledged and assigned to secure the obligations secured under our Master Indenture. A Utility Member cannot resell at wholesale any of the electric energy delivered to it under the wholesale electric service contract, unless such resale is approved by our Board or provided for in a schedule to the wholesale electric service contract.

The wholesale electric service contracts also provide for us to establish a committee every 5 years to review the wholesale electric service contracts for the purposes of making recommendations to our Board concerning any suggested modifications. The current contract committee began in March 2024 and is currently discussing various contract provisions, including extending the term of the wholesale electric service contract beyond 2050. The contract committee consists of a representative from each Utility Member that has elected to participate in the discussions.

We and our Utility Members are subject to regulations issued by FERC pursuant to PURPA with respect to the purchase of electricity from, and the sale of electricity to, qualifying facilities and co-generators. Our Board policy sets forth the terms for us to bill the Utility Member for fixed cost equalization to make up for the lost revenue that we forego as a result of the qualifying facilities sales to the Utility Member in excess of the 5 percent self-supply provision of the wholesale electric service contract. As part of the waiver of applicable FERC regulations approved by FERC involving us and 29 of our Utility Members, we will stand in place of those Utility Members to purchase capacity and energy from qualifying facilities that interconnect to distribution systems of those Utility Members who are participating in the waiver filing. We will make such purchase at a rate equal to our full avoided cost. As part of the waiver program, those participating Utility Members will sell supplementary, back-up, and maintenance power to the qualifying facilities.

Bring Your Own Resource Program

During 2024, we developed our BYOR Program, which is designed to provide our Utility Members with the flexibility to build, own or contract for power supply projects while avoiding cost shifts amongst our Utility Members. Under the BYOR Program, Utility Members interested in participating in the BYOR Program will propose projects that they will own or control and that do not exceed 40 percent of their 2022 peak load during our peak period and which projects will not have an adverse impact on our reliability, overall system costs or compliance with environmental objectives. If a Utility Member-proposed resource is accepted following the program evaluation process, a Utility Member will enter into an agreement enabling us to purchase the output of the BYOR project and that output will be deemed to serve the Utility Member's load. The Utility Member will pay us at our Class A wholesale rate schedule, including the output deemed to serve the Utility Member's load, and we will provide the Utility Member a credit on its wholesale electric service invoice for the output we purchase from the Utility Member.

In June 2024, we filed with FERC a tariff describing the parameters of the BYOR Program. In August 2024, FERC accepted our tariff and the inaugural BYOR Program cycle was initiated in the third quarter of 2024. Collectively 11 Utility Members brought four projects totaling 330 MWs in the inaugural BYOR Program cycle, with execution of agreements with us and the participating Utility Members expected in 2025.

Demand Response Program

During 2024, we engaged collaboratively with our Utility Members in developing a wholesale-led Demand Response Program anticipated to be filed with FERC in 2025. This program will enable us to work with our Utility Members to enroll the end-use devices of their customers, allow us to call upon the enrolled devices to modify load during peak load or high-cost periods. We expect this program to provide a benefit to all Utility Members through the reduction of our operational costs while allowing us to increase reliability and planning reserve margins, without building new generation or storage resources and avoiding the associated potential transmission upgrades.

Utility Members' Service Territories

Our Utility Members' service territories are diverse, covering large portions of Colorado, Nebraska, New Mexico and Wyoming and very small portions of Arizona, Montana, and Utah. In accordance with state regulations, our Utility Members have exclusive rights to provide electric service to retail customers within designated service territories. In Colorado, our Utility Members' service territories extend throughout the state and encompass suburban, rural, industrial, agricultural and mining areas. In Nebraska, our Utility Members' service territories are comprised primarily of rural residential and farm customers in the western part of the state. In New Mexico, our Utility Members' service territories extend throughout the northern, southern, central and western parts of the state, serving agricultural, rural residential, suburban, small commercial and mining customers. In Wyoming, our Utility Members' service territories extend from the north central to the southeastern part of the state and encompass rural residential, agricultural and mining areas. The differences in customer bases, economic sectors, climates and weather patterns of our Utility Members' service territories creates diversity within our system.

Eastern and Western Interconnection

North America is comprised of three major power grids, including the Western Interconnection and the Eastern Interconnection. The Western and Eastern Interconnection operate almost independently of each other with multiple direct current ties between the two grids. We have transmission facilities and serve our Utility Members' load in both the Western and Eastern Interconnection. In 2024, approximately 3.9 percent of our total load is located in the Eastern Interconnection. Our generating facilities are located in the Western Interconnection and generally isolated from our Utility Members' load in the Eastern Interconnection. We purchase, under a long-term Basin Eastern WPC, almost all the power which we require to serve our Utility Members' load in the Eastern Interconnection. See "— POWER SUPPLY RESOURCES — Purchased Power."

Contract Termination Payment and Relationship with Members

We are a cooperative corporation, and our Members are not our subsidiaries. We have no legal interest in, or obligation with respect to, any of the assets, liabilities, equity, revenue or margins of our Members except with respect to the obligations of our Members under their respective agreements with us. We have no control over or the right, ability or authority to control the electric facilities, operations, or maintenance practices of our Utility Members. Pursuant to our Bylaws, we and our Members disclaim any intent or agreement to be a partnership, joint venture, single or joint enterprise, or any other business form, except that of a cooperative corporation and member. The revenues of our Members are not pledged to us.

Pursuant to our Bylaws, a Member may only withdraw from membership in us upon compliance with such equitable terms and conditions as our Board may prescribe provided, however, that no Member shall be permitted to withdraw until it has met all its contractual obligations to us. In September 2021, we filed with FERC a modified contract termination payment methodology tariff as Rate Schedule 281 that provides a process should a Utility Member elect to withdraw from membership in us and terminate its wholesale electric service contract. The modified methodology was designed to protect the financial interests of our remaining Utility Members if a Utility Member elects to withdraw from membership in us. Our September 2021 Rate Schedule 281 included requirements for a two-year non-conditional notice and the payment of a contract termination payment. In simple terms, our modified contract termination payment amount as filed in September 2021 is the greater of (i) the withdrawing Utility Member's debt covenant obligation, and (ii) our lost revenue, which is the projected revenue the withdrawing Utility Member contractually agreed to pay over the remaining term of its wholesale electric service contract, less certain offsetting revenues we could earn by reselling the withdrawing Utility Member's share of energy and capacity and the net present value of the withdrawing Utility Member's patronage capital.

In October 2021, FERC accepted our modified contract termination payment methodology, effective November 1, 2021, subject to refund. FERC set the matter for hearing and instituted a concurrent FPA section 206 proceeding to determine the justness and reasonableness of our modified methodology.

A hearing on our modified contract termination payment methodology occurred in May 2022 before an administrative law judge at FERC. We, United Power, certain of our Utility Members, other parties, and FERC trial staff all presented different contract termination payment methodologies or adjustments thereto. In September 2022, the administrative law judge issued an initial decision and endorsed the FERC trial staff balance sheet methodology, with significant adjustments suggested by us. In October 2022, we, United Power, certain other Utility Members, and other parties filed exceptions to the initial decision.

In December 2023, FERC issued an order on the initial decision and adopted a further modified balance sheet approach for the contract termination payment methodology, which differs from the methodology we filed in September 2021. In January 2024, we, United Power, MPEI, and others filed requests for rehearing with FERC of its December 2023 order on the contract termination payment methodology. We and United Power filed petitions for review of FERC's December 2023 order. Our petition for review includes disputing FERC's rejection of our lost revenue approach. See "Note 14—Commitments and Contingencies—Legal" to the Consolidated Financial Statements in Item 8 for further information on the petition for review of FERC's December 2023 order.

In January 2024, we filed a revised Rate Schedule 281 with FERC with the contract termination methodology based upon FERC's December 2023 order that adopted a further modified balance sheet approach for the contract termination payment methodology. In March 2024, FERC issued an order accepting our January revised Rate Schedule 281 subject to further compliance filing, and established hearing and settlement judge procedures related to our sleeving administrative fee methodology set forth in our revised Rate Schedule 281. In April and June 2024, we submitted further revised versions of Rate Schedule 281 as directed by applicable FERC orders. In December 2024, FERC issued an order accepting both our April and June 2024 versions of Rate Schedule 281 subject to further compliance filing. FERC's December 2024 compliance filing order primarily addressed the calculation of the contract termination payment for Utility Members served in the Eastern Interconnection and the calculation of a transmission credit for withdrawing Utility Members in the Western Interconnection. In February 2025, we filed a revised Rate Schedule 281 with FERC as directed by FERC's December 2024 compliance filing order. We have reached an agreement in principle related to the sleeving administrative fee methodology.

The February 2025 revised Rate Schedule 281 uses our FERC financials and distinguishes between Utility Members served in the Western and Eastern Interconnection. For withdrawing Utility Members served solely on the Western Interconnection, their contract termination payment is equal to the withdrawing Utility Member's pro rata share, based upon Utility Member billing, of our long-term debt and certain other liabilities and also the withdrawing Utility Member's pro rata share of our power purchase obligations in the Western Interconnection. The power purchase obligations are based upon the difference between the weighted average contracted-for prices and the projected market prices for each category of power purchase contracts, with the withdrawing Utility Member's option to remarket, broker, or sleeve certain of our power purchase contracts. For withdrawing Utility Members in the Western Interconnection, we will create a regulatory liability for the transmission related long-term debt portion of the contract termination payment and provide a transmission credit, plus interest at FERC's proscribed interest rate, on the withdrawing Utility Member's post-withdrawal OATT transmission service bills from us, as the transmission provider.

For withdrawing Utility Members served solely in the Eastern Interconnection, the February 2025 revised Rate Schedule 281 provides their contract termination payment is our estimate of the amount we are required to pay Basin under the Basin Eastern WPC as a result of the Utility Member's withdrawal, subject to true-up after the amount is agreed to with Basin. The withdrawing Utility Member's payment also includes the negotiated amount of any radial facilities used to serve such Utility Member, which that Utility Member is required to purchase from us. For withdrawing Utility Members served in both the Western and Eastern Interconnection, the contract termination payment includes both parts of the calculation for Western and Eastern Interconnection Utility Members.

Withdrawing Utility Members may either choose to continue receiving accrued allocated patronage capital from us after its withdrawal when our Board retires patronage capital or take a discounted lump sum payment of its allocated patronage capital. If the Utility Member chooses the discounted lump sum option, the contract termination payment is reduced by such lump sum amount.

In April 2022, both United Power and NRPPD provided us non-conditional notices to withdraw from membership in us, with a May 1, 2024, withdrawal effective date. In January 2023, MPEI provided us a non-conditional notice to withdraw from membership in us, with a February 1, 2025, withdrawal effective date. In March 2024, LPEA provided us a non-conditional notice to withdraw from membership in us, with an April 1, 2026, withdrawal effective date.

On May 1, 2024, United Power withdrew from membership in us and terminated its wholesale electric service contract with us pursuant to the January 2024 Rate Schedule 281 on-file with FERC and a Membership Withdrawal Agreement with United Power. United Power’s contract termination payment amount was $709.4 million. United Power paid us an exit fee in cash of $627.2 million, after a regulatory liabilities credit and relinquishing its right to any patronage capital in us resulting in a discounted patronage capital credit of $82.2 million. Such amounts remain subject to true up in accordance with Rate Schedule 281 and United Power's Membership Withdrawal Agreement. Our Board deferred as a regulatory liability $530.1 million of United Power's $709.4 million contract termination payment amount. The remaining $179.3 million was related to a transmission credit for the portion of transmission debt allocated to United Power and required to be deferred pursuant to FERC's December 2023 order and Rate Schedule 281. The portion of the contract termination payment allocated to the transmission credit is subject to increase based upon FERC's December 2024 compliance filing order and FERC's acceptance of our February 2025 revised Rate Schedule 281.

NRPPD did not comply with the January 2024 Rate Schedule 281 on-file with FERC and made no contract termination payment to us. NRPPD’s wholesale electric service contract with us remains in effect and NRPPD remains a Class A member of us. NRPPD’s April 2022 notice of intent to withdraw was deemed null and void. In FERC's December 2024 compliance filing order, FERC confirmed NRPPD remains a Utility Member of us. In December 2024, NRPPD provided us a second non-conditional notice to withdraw from membership in us, with a January 1, 2027, withdrawal effective date. NRPPD is served solely in the Eastern Interconnection.

On February 1, 2025, MPEI withdrew from membership in us and terminated its wholesale electric service contract with us pursuant to the June 2024 Rate Schedule 281 on-file with FERC and a Membership Withdrawal Agreement with MPEI. MPEI’s contract termination payment amount was $86 million, including MPEI's pro rata share of our power purchase obligations in the Western Interconnection. MPEI paid us an exit fee in cash of $71.6 million and relinquished its right to any patronage capital in us resulting in a discounted patronage capital credit of $14.5 million. Such amounts remain subject to true up in accordance with Rate Schedule 281 and MPEI's Membership Withdrawal Agreement. Pursuant to FERC's December 2023 order and Rate Schedule 281, $19.7 million of MPEI's $86 million contract termination payment amount was related to a transmission credit for the portion of transmission debt allocated to MPEI and is required to be deferred. Consistent with prior withdrawals of Utility Members, we anticipate that some or all MPEI's remaining $66.3 million contract termination payment amount may be deferred as regulatory liabilities, subject to our Board's discretion. The portion of the contract termination payment allocated to the transmission credit is subject to increase based upon FERC's December 2024 compliance filing order and FERC's acceptance of our February 2025 revised Rate Schedule 281.

In March 2024, NRPPD filed a FPA section 206 complaint with FERC against us and Basin seeking, among other things, for FERC to hold that NRPPD's withdrawal from us is permissible under the Basin Eastern WPC. In December 2024, FERC denied NRPPD's complaint but held that NRPPD's withdrawal from us does not cause a breach of the Basin Eastern WPC as the Basin Eastern WPC allows us to transfer our Eastern Interconnection assets so long as we pay Basin the pro rata share of Basin's outstanding debt and other obligations and commitments. In January 2025, Basin filed a request for rehearing with FERC of its December 2024 order related to FERC's interpretation of the Basin Eastern WPC that NRPPD's withdrawal from us is not a breach of the Basin Eastern WPC. Basin's request for rehearing was denied by operation of law. Basin filed a petition for review of FERC's December 2024 order. See "Note 14—Commitments and Contingencies—Legal" to the Consolidated Financial Statements in Item 8 for further information.

In November 2023, LPEA filed a complaint for declaratory judgement and damages against us alleging, among other things, that we have breached our Bylaws and our wholesale electric service contract with LPEA. In November 2024, we and LPEA executed a settlement Term Sheet and, in January 2025, we filed a stipulation of dismissal of the lawsuit with prejudice. The court issued an order in January 2025 dismissing the lawsuit. See "Note 14—Commitments and Contingencies—Legal" to the Consolidated Financial Statements in Item 8 for further information.

Competition

In accordance with state regulations, our Utility Members have exclusive rights to provide electric service to retail customers within designated service territories. States in which our Utility Members’ service territories are located have not enacted retail competition legislation. Federal legislation could mandate retail choice in every state. Our Utility Members are subject to customer conservation and energy efficiency activities, as well as initiatives to utilize alternative energy sources, including self-generation, or otherwise bypass our Utility Members’ systems. Our Utility Members are also subject to competition for attracting new load as potential customers may locate their facilities in our Utility Member's designated service territory or the service territory of a neighboring utility.

In 1992, we entered into an agreement expiring in December 2025 with PSCO and PacifiCorp, two of the principal investor-owned utilities adjacent to our Utility Members' service territories in Wyoming and Colorado, that provides, among other things, that each of PSCO, PacifiCorp and us will:

- not make any hostile or unfriendly attempt to acquire or take over any stock or assets of any member served by another party to the agreement;
- respect all certificates of convenience and necessity and not attempt to serve any consumers within another's certified area; and
- seek to preserve territorial boundaries when threatened by municipal annexations.

We and our Utility Members are subject to competition from third party energy remarketing companies. Energy remarketing companies are targeting our Utility Members and the communities our Utility Members serve by claiming to be able to offer lower priced and cleaner wholesale electric power. This includes assisting our Utility Members in seeking to withdraw from membership in us and financing the withdrawal payment by our Utility Members. It also includes assisting some municipalities and tribes that our Utility Members serve by helping them create electric utilities.

RATE REGULATION

New Rate Developments

In May 2024, we filed with FERC a request to adopt a new Class A wholesale rate schedule (A-41) for electric power sales to our Utility Members. The filing included a 6.4 percent increase in our average wholesale rate. The wholesale rate maintains our postage stamp rate, with the same rate components for all our Utility Members, and incorporated a new formulary rate, which can be adjusted annually based on the budgets approved by our Board, including an annual true-up mechanism. In July 2024, FERC issued an order accepting our A-41 wholesale rate schedule, effective August 1, 2024, subject to refund. FERC further set our rate filing for settlement and hearing procedures and confirmed our accounting treatment, including amortization, and creation of regulatory assets for Escalante Station, Rifle Generating Station, Craig Station Units 2 and 3, and the New Horizon Mine environmental obligation. However, FERC did not authorize us to recover the regulatory assets that represent "acquisition costs/goodwill" for J.M. Shafer Generating Station and Colowyo Coal. These costs were on our books prior to us becoming subject to FERC's jurisdiction. We wrote off the J.M. Shafer Generating Station and Colowyo Coal "acquisition costs/goodwill" in 2024. Settlement discussions on our A-41 wholesale rate schedule are ongoing and the hearing is held in abeyance.

Rate Regulation

Our electric sales revenues are derived from wholesale electric service sales to our Utility Members and non-member purchasers. Revenues from wholesale electric power sales to our Utility Members are primarily from our Class A wholesale rate schedule established by our Board, but such rate schedule is subject to FERC acceptance or approval. Our wholesale electric service contracts with our Utility Members provide that rates paid by our Utility Members for the wholesale electric service we supply to them must be set at levels sufficient to produce revenues, together with revenues from all other sources, to meet our cost of operation, including reasonable reserves, debt and lease service, and development of equity.

On September 3, 2019, we became FERC jurisdictional for our Utility Member rates, transmission service, and our market-based rates. In December 2019, we filed with FERC our tariff filings, including our stated rate cost of service filing (A-40), market-based rate authorization, and transmission OATT. In March 2020, FERC issued orders generally accepting our tariff filings, subject to refund for sales after March 26, 2020. In August 2021, FERC approved our settlement agreement related to our Utility Members stated rate (A-40) that provided for us to implement a two-stage, graduated reduction in the charges making up our A-40 rate of 2 percent starting from March 1, 2021 until the first anniversary and 4 percent reduction (additional 2 percent reduction) on March 1, 2022 until the date a new Class A wholesale rate schedule goes into effect, which was August 1, 2024.

As part of the 2021 settlement agreement for our Utility Members' stated rate, we also agreed to file a new Class A rate schedule with FERC before September 1, 2023. We established a rate design committee to oversee the development of the new rate. In June 2023, we filed with FERC the new Class A rate schedule (A-41) that used a formula rate. In March 2024, FERC rejected our Class A formula rate resulting in our Class A rate schedule (A-40) remaining in effect. In May 2024, we filed with FERC a request to adopt a new revised Class A wholesale rate schedule (A-41) for electric power sales to our Utility Members that also uses a formula rate. In July 2024, FERC issued an order accepting our A-41 wholesale rate schedule, effective August 1, 2024, subject to refund.

Our Class A rate schedule (A-40) for electric power sales to our Utility Members that was in effect through July 2024 consisted of three billing components: an energy rate and two demand rates. Our new Class A formula rate schedule (A-41) for electric power sales to our Utility Members consists of eleven rate components, with three energy-based and eight demand-based and became effective in August 2024. For our A-41 rate schedule, our budget used to set our Utility Member formula rate is set by our Board, consistent with the provision of reliable cost-based supply of electricity over the long term to our Utility Members. Energy is the physical electricity delivered to our Utility Members. The energy-based rates are billed based upon a price per kWh of physical energy delivered and the demand-based rates are billed based on the Utility Member's highest thirty-minute integrated total demand measured in each monthly billing period during our peak period, Monday through Saturday, with the exception of six holidays.

We also provide wholesale electric power to non-members at contractual rates under long-term arrangements and at market prices in short-term transactions in the WACM, PSCO and PNM balancing authority areas, subject to FERC market-based rate authority. In July 2024, we filed with FERC a notice of change in status based upon changes in our system and stated that we failed FERC's market share analysis indicative screen in the WACM balancing authority area in just one of the four seasons. As part of our filing, we provided additional analysis and information that continues to support continued market-based rate authority in the WACM balancing authority area. FERC has not issued any orders or commenced any proceeding related to our notice of change in status.

Rate Policy

Under our Master Indenture, we are required to establish rates annually that are reasonably expected to achieve a DSR of at least 1.10 on an annual basis, and we are also required to maintain an ECR of at least 18 percent at the end of each fiscal year. Our Board Policy for Financial Goals and Capital Credits, approved and subject to change or waiver by our Board, sets guidelines to achieve margins and retain patronage capital sufficient to maintain a sound financial position and to allow for the orderly retirement of capital credits allocated to our Members.

Our Board Policy for Financial Goals and Capital Credits, approved in connection with our Board's approval of our new Class A rate schedule (A-41), includes three financial ratio goals for which Tri-State will set rates based upon an annual budget and true-up from the actual results of the previous fiscal year. The three financial goals are: (i) a minimum DSR of at least 1.15, (ii) a minimum ECR of at least 20 percent, and (iii) a minimum net margin attributable to us in each fiscal year of at least $20 million. Our management proposes rates that are expected to adequately recover our annual Utility Member revenue requirements contingent upon load projections and a budget approved annually by our Board. Our Board reviews the budget and our underlying rates on an annual basis in accordance with our financial goals and rate objectives, and in accordance with the financial covenants contained in our debt instruments. Our Master Indenture also requires that we review rates promptly at any point during the year upon any material change in circumstances which was not contemplated during the annual review of Utility Member rates. Any changes to our Class A rate schedule will be filed at FERC for their acceptance.

The following table shows our average Utility Member revenue/kWh for the years 2020 through 2024. The average Utility Member revenue/kWh is our total Utility Members' electric sales revenue in a given year divided by the total kilowatt hours sold to our Utility Members in that given year. The average Utility Member revenue/kWh does not represent the actual energy and demand rate components established by our Board and paid by our Utility Members for the years 2020 through 2024.

Year	Average Utility Member Revenue (Cents/kWh)
2024	7.392
2023	7.310
2022	7.342
2021	7.408
2020	7.531

Other FERC Regulation

In addition to FERC's jurisdiction over our wholesale rates to our Utility Members, cost-based rate tariff and market-based rate authority, FERC also regulates the issuance of securities and assumption of liabilities by us, as well as mergers, consolidations, the acquisitions of securities of other utilities, and the disposition of property subject to FERC jurisdiction. Under FERC regulations, we are prohibited from selling, leasing, or otherwise disposing of the whole of our facilities subject to

FERC jurisdiction, or any part of such facilities having a value in excess of $10 million without having FERC approval. We are also required to seek FERC approval prior to merging or consolidating our facilities with those of any other entity having a value in excess of $10 million. FERC also regulates certain of our transmission and generation operations, including reliability, transmission of electricity, and transmission planning. See "— TRANSMISSION."

POWER SUPPLY RESOURCES

We provide electric power to our Utility Members through a combination of generating facilities that we own, lease, or have undivided percentage interests in, and through the purchase of electric power pursuant to power purchase contracts and purchases on the open market.

In 2024, 39.6 percent of our energy available for sale was provided by our generation and 60.4 percent by purchased power. As part of Phase II of our approved 2023 ERP, we expect to enter into additional renewable power purchase contracts. We estimate that in 2025, approximately 50 percent of the energy our Utility Members use will come from clean sources.

Depending on our system requirements and contractual obligations, we are likely to both purchase and sell electric power during the same fiscal period. We use market transactions to optimize our position by routinely purchasing power when the market price is lower than our incremental production cost and routinely selling power to the short-term market when we have excess power available above our firm commitments to both Utility Members and non-members. We also use short-term market purchases during periods of generation outages at our facilities.

Generating Facilities

We own, lease or have undivided percentage interests in 1,550 MWs from coal-fired base load facilities and 822 MWs from gas/oil-fired facilities. See "PROPERTIES" for a description of our various generating facilities.

In September 2016, we announced that the owners of Craig Station Unit 1 intend to retire Craig Station Unit 1 by December 31, 2025, which includes our 102 MW share from such unit. In January 2020, we announced that our Board approved the early retirement of Craig Station Units 2 and 3. Our share of Craig Station Unit 2 is 98 MWs. We and the other joint owners of Craig Station Unit 2 intend to retire Craig Station Unit 2 by September 30, 2028. We own and operate the 448 MW Craig Station Unit 3. As part of our Phase I of our approved 2023 ERP, we intended to retire Craig Station Unit 3 by January 1, 2028. The early retirement of Craig Station is expected to impact approximately 155 employees.

As part of Phase I of our approved 2023 ERP and subject to receipt of New ERA Program funding related to Springerville Unit 3 and reaching agreements with the applicable parties, we intended to retire Springerville Unit 3 by March 1, 2031.

In March 2024, we executed an asset purchase agreement to purchase the 145 MW Axial Basin Solar project being developed in northwestern Colorado located near the Colowyo Mine. Concurrent with execution of the purchase agreement, we also executed an engineering, procurement and construction contract with an affiliate of the developer of the project. In April 2024, we closed on the acquisition of Axial Basin Solar project, terminated the power purchase contract for this project, and issued a notice to proceed with construction to the contractor.

In April 2024, we executed an asset purchase agreement to purchase the 110 MW Dolores Canyon Solar project being developed in southwestern Colorado. Concurrent with execution of the purchase agreement, we also executed an engineering, procurement and construction contract with an affiliate of the developer of the project. In May 2024, we closed on the acquisition of Dolores Canyon Solar project, terminated the power purchase contract for this project, and issued a notice to proceed with construction to the contractor.

Construction for both projects is progressing and both projects are expected to achieve commercial operation in the second half of 2025. We also expect to utilize direct pay of federal tax benefits as provided in the IRA for both projects.

Our generating facilities are included in the Western Power Pool reserve sharing pool. This pool facilitate sharing of generation reserves to be activated during a system emergency, such as loss of a generating unit or transmission line.

Purchased Power

We supplement our capacity and energy requirements not supplied by our generating facilities through long-term purchase contracts and short-term energy purchases. Our largest long-term power purchase contracts are discussed below.

Renewables. We have entered into renewable power purchase contracts to purchase the entire output from specified renewable facilities totaling approximately 1,118 MWs, including 674 MWs of wind-based power purchase contracts and 425 MWs of solar-based power purchase contracts, of which 1,118 MWs are in operation. The largest of these renewable power purchase contracts are summarized in the table below. A majority of our renewable power purchase contracts include the option for us to purchase the renewable facility at certain points during the term of the power purchase contract.

Facility Name	Location	Counterparty	Capacity (MW)	Year of Commercial Operation	Year of Contract Expiration
Solar					
Cimarron Solar	New Mexico	Southern Turner Cimarron I, LLC	30	2010	2035
San Isabel Solar	Colorado	San Isabel Solar LLC	30	2016	2041
Escalante Solar	New Mexico	Escalante Solar, LLC	200	2024	2041
Alta Luna Solar	New Mexico	TPE Alta Luna, LLC	25	2017	2042
Spanish Peaks Solar I	Colorado	Spanish Peaks Solar, LLC	100	2024	2043
Spanish Peaks Solar II	Colorado	Spanish Peaks II Solar, LLC	40	2024	2043
Wind					
Kit Carson Windpower	Colorado	Kit Carson Windpower, LLC	51	2010	2030
Colorado Highlands Wind	Colorado	Colorado Highlands Wind, LLC	94	2012	2032
Crossing Trails Wind	Colorado	Crossing Trails Wind Power Project, LLC	104	2021	2036
Niyol Wind	Colorado	Niyol Wind, LLC	200	2021	2041
Carousel Wind Farm	Colorado	Carousel Wind Farm, LLC	150	2016	2041
Twin Buttes II Wind	Colorado	Twin Buttes Wind II, LLC	75	2017	2042

In addition to the renewable power purchase contracts in the table above, we have long-term renewable power purchase contracts with WAPA. Substantially all of our purchases from WAPA are hydroelectric-based power made at cost-based rates under long-standing federal law under which WAPA sells power to cooperatives, municipal electric systems and certain other "preference" customers. WAPA markets and transmits the power to us pursuant to two contracts, (i) one contract relating to WAPA’s LAP that terminates September 30, 2054 and (ii) one contract relating to WAPA’s SLCAIP that terminates September 30, 2057. The LAP generally consists of generation and transmission facilities located in the Missouri River Basin. The SLCAIP generally consists of generation and transmission facilities located in the Colorado River Basin. The following table shows the contractual long-term power delivery from WAPA in the summer season (April-September) and the winter season (October-March):

Resource:	Summer (MW)	Winter (MW)
Loveland Area Projects (LAP) January 1 - September 30, 2024	349	285
Loveland Area Projects (LAP) October 1 - December 31, 2024	346	282
Salt Lake City Area/Integrated Projects (SLCAIP)	231	247
Total January 1 - September 30, 2024	580	532
Total October 1 - December 31, 2024	577	529

Effective October 1, 2024, our LAP capacity and energy allocations decreased by 1 percent due to the WAPA LAP 2025 Resource Pool. For 2024, our SLCAIP capacity allocations decreased by 21 percent compared to our full entitlement and energy allocations decreased by 38 percent compared to our full entitlement. Reservoir levels along with precipitation will be the driving factors in our future SLCAIP contract allocations.

Basin. We have two wholesale power contracts with Basin: one for the Western Interconnection and one for the Eastern Interconnection. Both wholesale power contracts continue through December 31, 2050 and are subject to automatic extension thereafter until either party provides at least five years’ notice of its intent to terminate.

The Basin Eastern WPC provides the terms under which we purchase in the Eastern Interconnection all the power which we require to serve our Utility Members’ load in the Eastern Interconnection other than a very small portion of Utility Members' load in the Eastern Interconnection in New Mexico. The Utility Members’ peak load in the Eastern Interconnection in 2024 was approximately 323 MWs.

The wholesale power contract for the Western Interconnection provides the terms under which we purchase in the Western Interconnection fixed scheduled quantities of electric power and energy. The quantity of electric power and energy varies depending on the month and hour with a maximum of 268 MWs occurring during certain hours in July.

In addition to long-term power purchase contracts, we utilize market purchases to optimize our position by routinely purchasing power when the market price is lower than our incremental production cost. We also utilize short-term market purchases during periods of generation outages. In addition, we have a hazard sharing arrangement with TEP, which provides for supply of power to us in the event of forced outages at specified generating facilities.

Power Sale Contracts

We have a long-term power sales contract to sell Salt River Project 100 MWs of power, contingent on the operation of Springerville Unit 3, which expires in August 2036. We have a long-term power sales contract to sell WAPA up to 65 MWs of power, which expires in December 2025.

In anticipation of excess capacity resulting from Utility Member withdrawals in 2024, 2025, and 2026, we have entered into multiple power sales contracts with third parties for up to 515 MWs and multiple tolling agreements for 250 MWs in total from units at our simple-cycle combustion turbines, including Knutson, Limon, and Pyramid Generating Stations for the sale of capacity and energy. A tolling agreement is an arrangement whereby the purchaser provides its own natural gas for generation of electricity. The power sales contracts and tolling agreements have different commencement and termination dates, with 265 MWs of the power sales contracts, which includes the above referenced WAPA 65 MW sale, and 180 MWs of the tolling agreements currently in effect.

In addition to long-term power sales contracts, we routinely sell power to the short-term market when we have excess power available above our firm commitments to both Utility Members and non-members.

We are subject to varying degrees of competition related to the sale of excess power to non-members on both a short-term and long-term basis. We are subject to competition from regional utilities and merchant power suppliers with similar opportunities to generate and sell energy at market-based prices and larger trading entities that do not own or operate generating assets.

Organized Markets

We have all our load in organized markets. We participate in SPP’s Western Energy Imbalance Service market that generally covers our load and resources in Colorado, western Nebraska located in the Western Interconnection, and the eastern half of Wyoming. This imbalance market centrally dispatches energy from these participants through the region every five minutes. Approximately 69 percent of our load is in this market.

We also participate in the CAISO Western Energy Imbalance Market. This affects our load and resources within the PNM balancing authority area, which is all our load and resources in New Mexico. We have registered our New Mexico resources and Springerville Unit 3 generation as participating resources with CAISO in order for our generation to participate in this imbalance market. We have a small amount of load located in the PacifiCorp balancing authority area in the CAISO Western Energy Imbalance Market.

Our load and transmission facilities in the Eastern Interconnection, largely in Nebraska, have been in the SPP regional transmission organization since 2016.

In September 2023, we announced our commitment, along with Basin, WAPA, Municipal Energy Agency of Nebraska, Deseret Power Electric Cooperative, Colorado Springs Utilities, and Platte River Power Authority, to become a full member of SPP's regional transmission organization expansion into the Western Interconnection. We expect the expansion of SPP's service territory from the Eastern Interconnection into the Western Interconnection to be completed in the first half of 2026 at which time certain of our load and transmission facilities in the Western Interconnection will be part of the SPP regional transmission organization. We believe a Western Interconnection regional transmission organization is necessary to achieve the full benefits of organized markets and to meet state laws regarding reductions in CO_2 emissions.

Resource Planning

We continually evaluate potential resources required to serve the long-term requirements of our Utility Members. As part of our approach to resource planning, we evaluate various resource options, including the construction of new resources and long-term power purchase contracts. In evaluating future portfolio additions, we monitor market conditions, tax credit expiration schedules, impacts of current resources on reliable system operations and the operation of existing generation assets, transmission system capacity, our potential participation in a regional transmission organization in the Western Interconnection, and the regulatory requirements for meeting Electric Resource Plan rules, RPS and RES and other state laws regarding reductions in CO_2 emissions.

In December 2023, we filed Phase I of our 2023 ERP with the COPUC, which contained our preferred plan. Our preferred plan is the IRA scenario that forecasted the need for approximately 1,500 MWs of new resources during the resource acquisition period of 2026-2031. Our preferred plan retires Craig Station Unit 3 by January 1, 2028 and, if we receive New ERA Program funding and reach agreements with the applicable parties, our preferred plan retires Springerville Unit 3 by March 1, 2031. In June 2024, we filed an unopposed executed comprehensive settlement agreement for Phase I of our 2023 ERP with the COPUC supporting its approval subject to the terms of the settlement, including the above referenced retirements of our generating facilities. The settlement also added a demand response target for our Colorado peak load in 2030 of 5.5 percent. The settlement agreement further provides for us to provide community assistance for northwest Colorado, which is the location of Craig Station. Community assistance includes $22 million in direct total benefit to the northwest Colorado community between 2026 and 2029, with other potential investments providing up to $48 million in additional benefit to such community between 2028 and 2038. In August 2024, the administrative law judge for the COPUC recommended approval of the settlement agreement and the approval became effective in September 2024.

For Phase II of our 2023 ERP, during our resource procurement process, we issued three requests for proposals in September 2024 seeking bids for new dispatchable, renewable, and storage resources for the resource acquisition period of 2026-2031. We received 145 bids related to 128 projects for over 21,000 MWs from these projects. We advanced 52 of these bids to Phase II modeling. These shifts in our generation portfolio included in our preferred plan over the coming years are expected to result in significant greenhouse gas emissions reduction for our wholesale electricity sales in Colorado in 2030, with respect to a verified 2005 baseline. This includes meeting Colorado statutory emissions reduction target of 80 percent in 2030.

Fuel and Water Supply

Coal. We purchase coal under long-term contracts. See "PROPERTIES" for a description of our investments in coal mines. The following table summarizes the sources of our coal for each of our coal-fired generating facilities:

Generating Station	Mine	Contract End Date
Craig Station Units 1 and 2	Colowyo Mine	2029 (1)
Craig Station Unit 3	Colowyo Mine	2029 (1)
Laramie River Generating Station	Various, including Dry Fork Mine	2041
Springerville Unit 3	North Antelope Rochelle Mine	2027

(1) We expect to align the terminations of these contracts with the respective closure of the generation units.

Colowyo Mine. Colowyo Coal, a subsidiary of ours, is actively mining the Collom pit at the Colowyo Mine. In September 2024, our Board decided to transition from mining to full reclamation at the Colowyo Mine by the end of 2025.

Reclamation Liabilities. In connection with our use of coal derived from coal mining facilities in which we have an ownership interest, including the Colowyo Mine and the New Horizon Mine, there are certain reclamation activities mandated by state and federal laws. These liabilities are recognized and recorded on our financial statements when required by accounting guidelines. We provide surety bonds from third party sureties for our reclamation obligations at the Colowyo Mine and the New Horizon Mine in accordance with Colorado requirements. The amounts of such bonds are based upon Colorado requirements and are different than the amount of liabilities recognized on our financial statements in accordance with GAAP.

Natural Gas. The majority of natural gas we purchase is to fill peak demands, and as replacement energy for forced outages and curtailments on coal units and renewable resources. We currently purchase the majority of our gas supplies on the spot market at fixed daily prices and on occasion we enter into forward fixed-price, fixed-quantity physical contracts. The majority of natural gas is purchased in the Cheyenne Hub area, which is in close proximity to the natural gas generating facilities we tend to utilize most frequently. This includes purchases from our Non-Utility Member, MIECO, Inc. Six major natural gas pipelines have interconnections at the Cheyenne Hub, and presently there is generally adequate supply at this location. Based on the regional forecast of production activities and pipeline capacity in the Rocky Mountain region, we presently anticipate that sufficient supplies of natural gas will generally be available in the foreseeable future. During extreme weather events, the availability of natural gas may be limited. We have a long-term natural gas transportation contract that provides firm rights to move natural gas from various receipt points to our facilities. Finally, we may utilize financial instruments to price hedge our forecasted natural gas requirements.

Oil. Distillate fuel for the Burlington, Limon, Knutson and Pyramid Generating Stations, all simple-cycle combustion turbine facilities, is purchased on the spot market from various suppliers. Oil is transported to the respective locations via truck.

Water Supply. We use varying amounts of water for the production of steam used to drive turbines that turn generators and produce electricity in our generating facilities. We maintain a water portfolio that supplies water from various sources for each of our generating facilities. This portfolio is adequate to meet the water supply requirements of our generating facilities. Temporary supplies are also typically available on a short-term or annual basis from third-party water providers. Our generating facilities are located in the western part of the U.S. where demand for available water supplies is heavy, particularly in drought conditions. Litigation and disputes over water supplies are common and sometimes protracted, which can lead to uncertainty regarding any user's rights to available water supplies. If we become subject to adverse determinations in water rights litigation or to persistent drought conditions, we could be forced to acquire additional temporary or permanent water supplies or to curtail generation at our facilities.

TRANSMISSION

As of December 31, 2024, we had ownership or capacity interests in approximately 5,819 miles of transmission lines and own or have major equipment ownership in 407 substations and switchyards. See "PROPERTIES" for a description of our transmission facilities.

Our system is interconnected with those of other utilities, including WAPA, Nebraska Public Power District, Black Hills Colorado Electric, PacifiCorp, PSCO, Platte River Power Authority, Colorado Springs Utilities, Basin, TEP, PNM and Deseret Power Electric Cooperative. The majority of our transmission facilities operate as part of the Western Interconnection. The Western Interconnection consists of transmission assets that link generating facilities to load centers throughout the region. A small portion of our facilities support our load centers in the Eastern Interconnection. We continue to make the capital investment necessary to expand our transmission infrastructure and participate in many joint projects with other transmission owners to provide electric service to our Utility Members.

The FPA authorizes FERC to oversee the sale at wholesale and transmission of electricity in interstate commerce by public utilities, as that term is defined in the FPA. We are subject to the general "public utility" regulation of FERC under the FPA and are under FERC jurisdiction for rates and transmission service.

FERC requires public utilities to comply with several requirements, including the requirements to provide open access transmission service and engage in regional planning of transmission facilities. We are also subject to reporting obligations applicable to all electric utilities, other FERC orders, and FERC's oversight with respect to transmission planning, investment and siting, reliability standards, price transparency, and market manipulation. We are subject to regulations issued by FERC pursuant to the Energy Policy Act of 1992 and the Energy Policy Act of 2005 with respect to the provision of certain transmission services.

We are a member of SPP and have transferred operational authority (but not ownership) of our transmission facilities that are located in the Eastern Interconnection to SPP, a regional transmission organization. See "— POWER SUPPLY RESOURCES – Organized Markets" regarding SPP's expansion to the Western Interconnection.

Open Access Transmission Service

FERC requires public utilities to provide open access transmission service. Open access generally gives all potential users of the transmission grid an equal opportunity to obtain the transmission service necessary to support purchases or sales of electric energy, thereby promoting competition in wholesale energy markets. Use of our transmission facilities is governed by OATTs. Use of our Eastern Interconnection transmission facilities is governed by the SPP OATT and our costs of providing transmission service in the Eastern Interconnection are subject to review by FERC. Use of our Western Interconnection transmission facilities is governed by our OATT filed with FERC and our costs of providing transmission service in the Western Interconnection are subject to review by FERC.

FERC has additional oversight authority over us under Sections 210 and 211 of the FPA, which apply to all transmitting utilities. Under these sections, FERC may, upon application by a customer, compel a utility to provide interconnection and transmission service to that customer, subject to appropriate compensation. We have not been the subject of an order under these provisions of the FPA.

Transmission Planning

FERC has become increasingly involved in promoting the development of the transmission grid. In FERC Order No. 890, FERC expressly required coordinated transmission planning and established governing principles. We comply with this requirement through our participation in WECC, WestConnect, SPP, and other sub-regional transmission planning groups and processes. In FERC Order No. 1000, FERC required all public utilities to engage in regional and interregional transmission planning and cost allocation. We comply with Order No. 1000 by participating in regional and interregional transmission planning and cost allocation processes in SPP and WestConnect. WestConnect is a voluntary organization of transmission providers committed to assessing stakeholder needs in the Southwest. The participants in WestConnect own and operate transmission systems in all or part of the states of Arizona, Colorado, Montana, Nebraska, New Mexico, South Dakota, Texas, Utah, and Wyoming.

FERC has also provided for rate incentives for public utilities as a means of encouraging investment in new transmission facilities. Recent approvals by FERC of rate incentives for transmission projects in our region and elsewhere have provided us with practical guidance as to the applicability of these incentives to potential future transmission projects.

Wildfire Mitigation

We actively engage in wildfire mitigation activities and have done so for over 15 years. We have developed a detailed wildfire mitigation plan for our service territory and are in the process of updating it. Our plan serves to assess wildfire risk driven by fuels, climate and topography and then determine the most suitable wildfire mitigation strategy. Our mitigation strategy has evolved over time to address our diverse territory. We also perform system-wide wildfire risk assessments.

For the transmission lines that we maintain, we perform periodic inspections with the increasing usage of drones and remote sensors to support certain of our inspections. We also engage in local wildfire protection plans and other emergency management planning exercises.

Reliability

Section 215 of the FPA authorizes FERC to oversee the reliable operation of the nation's interconnected bulk power system. In 2007, FERC approved mandatory national reliability standards for administration by NERC. The national standards apply to all utilities that own, operate, and/or use generating or transmission facilities as part of the interconnected bulk power system. As an owner, operator and user of generation and transmission facilities, we are subject to some of these reliability standards. Under the national standards, utilities must, among other things, respond to emergencies within stated time periods, maintain prescribed levels of generation reserves, and follow instructions concerning load shedding. FERC also approved limited delegations of authority to six regional entities. We are registered in two of the six regional entities: WECC and MRO.

We have an active compliance monitoring program that covers all aspects of our generation and transmission reliability responsibilities. We also collaborate with our Utility Members on areas where transmission and distribution system reliability responsibilities overlap. NERC and its regional entities, including WECC and MRO, periodically audit compliance with reliability standards. In addition to audits and spot-checks (unscheduled audits), NERC and its regional entities, including WECC and MRO, are also authorized to conduct other types of investigations, including requiring annual "self-certifications" of compliance with select reliability standards.

In 2024, we were audited by WECC and are scheduled for a future compliance audit in 2027 as part of a three-year routine audit cycle. WECC continues to evaluate the findings of the 2024 audit, however, we do not expect there to be any significant enforcement actions and we do not expect any financial penalties.

ENVIRONMENTAL REGULATION

We are subject to various federal, state and local laws, rules, regulations, and affected by directives and executive orders with regard to the following:

- air quality, including greenhouse gases;
- water quality; and
- other environmental matters.

These laws, rules and regulations often require us to undertake considerable efforts and incur substantial costs to maintain compliance and obtain licenses, permits and approvals from various federal, state and local agencies. We estimate that we spend over $1,200,000 per year in fees, as well as increased operating costs to ensure compliance with environmental standards in federal and state statutes and regulations, described below. If we fail to comply with these laws, regulations, licenses, permits, approvals, directives and executive orders, as applicable, we could be held civilly or criminally liable.

Our operations are subject to environmental laws and regulations that are complex, change frequently and have generally become more stringent and numerous over time. Federal, state and local standards and procedures that regulate the environmental impact of our operations are subject to change. These changes may arise from continuing legislative, regulatory and judicial actions regarding such standards, procedures, and executive orders. Consequently, there is no assurance that environmental regulations applicable to our facilities will not become materially more stringent, or that we will always be able to obtain all required operating permits. An inability to comply with environmental standards could result in reduced operating levels or the complete shutdown of our facilities that are not in compliance, including the shutting down of additional generating facilities or the shutting down of individual coal-fired generating facilities earlier than scheduled. We cannot predict at this time whether any additional legislation or rules will be enacted which will affect our operations, and if such laws or rules are enacted, what the cost to us might be in the future because of such actions.

From time to time, we are alleged to be in violation or in default under orders, statutes, rules, regulations, permits or compliance plans relating to the environment. Additionally, we may need to deal with notices of violation, enforcement proceedings or challenges to construction or operating permits. In addition, we may be involved in legal proceedings arising in the ordinary course of business.

Since 1971, we have had in place a Board Policy for Environmental Compliance that is reviewed periodically by our Board. The policy commits us to comply with all environmental laws and regulations. The policy also calls for the implementation of an internal EMS. We have developed and implemented the EMS over the last twenty years. The EMS meets the EPA guidance for management systems and consists of policies, procedures, practices and guides that assign responsibility and help ensure compliance with environmental regulations.

2025 Presidential Administration Change

We are tracking environmental and permitting policy directives, memos, and executive orders issued by the new federal administration. While several of these documents have relevance to the electric power sector, it is too early to tell what most of these will mean for us in practice and it is unclear what will survive known and expected legal challenges. This is a dynamic situation, and we are monitoring these presidential transition activities to evaluate relevance, risk, and impact to our operations and plans.

State Environmental and Renewable Energy/Portfolio Standards

In Colorado, the AQCC is required to develop rules to reduce statewide greenhouse gas emissions 26 percent by 2025, 50 percent by 2030, and 90 percent by 2050, relative to 2005 emissions. As part of the settlement agreement related to our 2020 Electric Resource Plan that became effective in April 2022, we have agreed to reduce the greenhouse gas emissions related to our wholesale electricity sales in Colorado as follows: at least 26 percent in 2025, 36 percent in 2026, 46 percent in 2027, and 80 percent in 2030, with respect to the verified 2005 baseline.

In Colorado, the RES requires our Colorado Utility Members to obtain 10 percent of their energy requirements from renewable sources and requires we provide to our Colorado Utility Members at least 20 percent of the energy at wholesale from renewable resources. In Colorado, we are permitted to count renewable sources utilized by our Colorado Utility Members for their RES requirement towards compliance with our separate RES requirement.

In New Mexico, the RPS requires our New Mexico Utility Members to obtain 10 percent of their energy requirements from renewable sources. The RPS further requires our New Mexico Utility Members to obtain 40 percent renewable energy by 2025 and 50 percent renewable energy by 2030 and adds a target of achieving a zero carbon resource standard by 2050 with at least 80 percent renewable energy. In New Mexico, regulatory relief is provided for the 2050 target if implementing the provisions are not technically feasible, hamper reliability or increase the cost of electricity to unaffordable levels.

We currently provide sufficient energy from renewable sources to meet our Utility Members’ current obligations under the RPS or RES requirements in New Mexico and Colorado, as applicable, and expect to be able to continue meeting our Utility Members’ RPS/RES obligations in 2025 to the extent a Utility Member does not meet its obligation with renewable generation owned or controlled by such Utility Member as permitted under our wholesale electric service contract. We expect to be able to achieve compliance with our separate RES that requires 20 percent of the energy we provide to our Colorado Utility Members at wholesale to come from renewable sources in 2025.

The impacts of the RPS or RES requirements in New Mexico and Colorado, as applicable and our compliance with the settlement agreement related to our 2020 Electric Resource Plan, and our 2023 Electric Resource Plan, could include modifications to the design or operation of existing facilities, increases in our operating expenses and potential stranded costs, investments in new generation and transmission facilities, the closure of additional generating facilities, the closure of individual coal-fired generating facilities earlier than scheduled, and other impacts additional to the closures of coal-fired generating facilities.

Air Quality

The Clean Air Act. Pursuant to the Clean Air Act, the EPA has adopted standards regulating the emission of air pollutants from generating facilities and other types of air emission sources, establishing national ambient air quality standards for criteria pollutants, and requiring permitting of both new and existing sources of air pollution. The Clean Air Act requires that the EPA periodically review, and revise if necessary, its adopted emission standards and national ambient air quality standards. Both of these actions can impose additional emission control and compliance requirements, increasing capital and operating costs. Among the provisions of the Clean Air Act that affect our operations are (1) the acid rain program, which requires nationwide reductions of SO_2 and NOx from existing and new fossil fuel-based generating facilities, (2) provisions related to major sources of toxic or hazardous air pollutants, (3) New Source Review, which includes requirements for new plants that are major sources and modifications to existing major source plants, (4) National Ambient Air Quality Standards that establish ambient air quality limits for criteria pollutants, and (5) requirements to address visibility impacts from regional haze. Many of the existing and proposed regulations under the Clean Air Act impact coal-fired generating facilities to a greater extent than other sources; however, EPA has turned its attention to natural gas fired generating resources and is developing new regulatory requirements.

Our facilities are currently equipped with pollution controls to ensure emissions of SO_2, NOx, and particulates meet or exceed the requirements of the Clean Air Act and our air permits. As needed, some specified units have appropriate mercury emission controls. All three units at Craig Station have scrubbers to remove SO_2, baghouses for particulate removal, and low NOx burners. Craig Station Unit 2 has selective catalytic reduction equipment for NOx control and Craig Station Unit 3 has selective non-catalytic reduction equipment for NOx control and an activated carbon injection system to control mercury emissions.

Basin is the operator of the Laramie River Generating Station and is responsible for environmental compliance for that facility. Laramie River Generating Station is comprised of three coal fired generating units. All three units at Laramie River Generating Station use electrostatic precipitators to control the emissions of particulate matter. Units 1 and 2 use dry scrubbers to control the emissions of SO_2 while Unit 3 uses a wet scrubber to control SO_2 emissions. Unit 1 at Laramie River Generating Station uses a selective catalytic reduction system to control the emissions of NOx while Units 2 and 3 use a selective non-catalytic reduction to control the emissions of NOx. If liabilities arise as a result of a failure of environmental compliance at Laramie River Generating Station, our responsibility for those liabilities is governed by the operating agreement for that facility.

TEP is the operator of Springerville Unit 3 and is responsible for environmental compliance of that station. Springerville Unit 3 operates under a Title V air operating permit that includes all Springerville Generating Station units. Springerville Unit 3 has scrubbers to remove SO_2, a baghouse for particulate removal, low NOx burners and selective catalytic reduction equipment for NOx control, and an activated carbon injection system for controlling mercury emissions. If liabilities arise as a result of a failure of environmental compliance at Springerville Unit 3, our responsibility for those liabilities is governed by the operating agreement for that facility.

We own and operate combustion turbine generating facilities that burn natural gas and/or fuel oil at four locations in Colorado and one in New Mexico. The combustion turbines are subject to emission limits lower than those of coal-fired generating facilities. All units have the necessary environmental permits in place and are operated to meet or surpass regulatory requirements. Steam turbine facilities include steam injection to control NOx emissions by lowering thermal NOx formation.

Acid Rain Program. The acid rain program achieves nationwide reductions of SO_2 and NOx emissions by requiring reductions in allowable emission rates and by allocating emission allowances to generating facilities for SO_2 emissions based on historical or calculated levels. We are allocated and hold sufficient SO_2 allowances to ensure compliance with the acid rain program.

Greenhouse Gas Regulation. In May 2024, the EPA published a final rule regarding emission guidelines for CO_2 from certain existing electric generating units under Section 111(d) of the Clean Air Act and certain new electric generating units under Section 111(b) of the Clean Air Act. The EPA finalized a matrix of emission requirements that depend on a given unit's fuel type, generating capacity, capacity factor, and years of continued operation. Due to applicability thresholds and previously announced retirement dates of our generating facilities, this particular rule does not, or likely will not, affect most of our generating facilities. However, if not overturned, the rule will drive important decision-making about future operation of and investment in Laramie River Generating Station. The regulation is subject to litigation, which has been held in abeyance until an April 21, 2025 deadline for EPA to file a motion to govern further proceedings.

Mercury and other Hazardous Air Pollutants. In May 2024, the EPA published final revisions to the National Emission Standards for Hazardous Air Pollutants for coal- and oil-fired electric utility steam generating units pursuant to the EPA's risk and technology review as required by Section 112 of the Clean Air Act. The EPA finalized a more stringent emission limit for particulate matter, as a surrogate for non-mercury metals, and requirements for installations of particulate matter continuous emissions monitoring systems on all of our coal-fired units, except for Craig Unit 1, due to its retirement date. The revisions are subject to litigation.

In June 2022, Public Protections from Toxic Air Contaminants Act was signed into Colorado law. The law requires larger stationary air pollution sources in Colorado, including electric generating facilities, to report facility-wide emissions of toxic air contaminants annually. The first report was due on June 30, 2024. We timely submitted this report. The State of Colorado developed a list of between 300 and 400 toxic air contaminants that, if emitted, must be reported to the state. The law also requires that Colorado by April 30, 2025 identify up to five priority toxic air contaminants that may pose a risk of harm to public health and by April 30, 2026 propose health-based standards. Colorado adopted into regulation five priority toxic air contaminants and plans to act soon on a proposal for more defined and stringent reporting requirements. We emit some of the five priority toxic air contaminants and are likely to have additional reporting requirements, and perhaps other requirements, under this new program.

National Ambient Air Quality Standards. In October 2015, the EPA lowered the NAAQS for ozone from 75 ppb to 70 ppb. The J.M. Shafer Generating Station and Knutson Generating Station are located in the DM/NFR ozone nonattainment area. The DM/NFR ozone nonattainment area did not meet the 2008 ozone NAAQS of 75 ppb or the 2015 ozone NAAQS of 70 ppb. In 2019, the EPA reclassified the DM/NFR ozone nonattainment area from "moderate" to "serious" nonattainment for the 2008 ozone NAAQS of 75 ppb. The DM/NFR ozone nonattainment area again failed to meet the 2008 ozone NAAQS and the State of Colorado and the EPA redesignated the area from "serious" to "severe" nonattainment in 2022. At the same time, the DM/NFR also failed to attain the 2015 ozone NAAQS (70 ppb) and the State of Colorado and the EPA redesignated the area from "marginal" to "moderate" nonattainment. The DM/NFR ozone nonattainment area developed a plan to comply with the 2008 and 2015 ozone NAAQS; however, the plan did not demonstrate compliance by 2023 as required, but showed compliance by 2026. Additional redesignations to more stringent nonattainment status are possible. The EPA is now in its regular recurring five-year process of reevaluating the efficacy of the ozone standard(s) and is working to determine if the national standard for ozone is adequate to protect public health and the environment. Implementation of a lower ozone standard will require the evaluation of additional emission controls for many major sources in the DM/NFR nonattainment area. In the 2022 plan development effort, additional emission controls were not required at the J.M. Shafer Generating Station and the Knutson Generating Station, but could be required under future redesignation evaluations.

Transport Rule/Good Neighbor Plan. In 2022, the EPA proposed a rule that would implement a Federal Implementation Plan to assure that states identified in the proposal would not significantly contribute to violations of air quality standards in downwind states that are working to attain or maintain the 2015 8-hour ozone NAAQS. The proposed rule would have required significant NOx emission reductions across 26 states, including Wyoming, at coal-fired electric generation units, including Laramie River Generating Station. The EPA finalized the proposed rule in March 2023 and excluded Wyoming from the program. In the final rule, the EPA signaled that it planned to include Arizona in the program after it reassessed the modeling for the state. In February 2024, the EPA proposed a new rule to include Arizona and New Mexico in the program. The comment period for the February 2024 proposal closed in May 2024. It was anticipated that the EPA would issue a final rule regarding the inclusion of Arizona and New Mexico in the fourth quarter of 2024 or the first quarter of 2025, but nothing has been forthcoming from EPA. Several states have challenged the final rule and others have filed petitions with the courts to stay the effectiveness of the proposed rule until the resolution of the legal challenges. The courts granted all the petitions for stays of effectiveness and EPA issued a blanket stay across the entire program. It is uncertain if or when any new requirements may be finalized or take effect, or if the final rule that was adopted will be upheld in the courts.

Regional Haze. In June 2005, the EPA issued the Clean Air Visibility Rule, amending its 1999 Regional Haze Rule, which had established timelines for states to improve visibility in national parks and wilderness areas throughout the U.S. Under the amended rule, states were required to evaluate certain types of older sources and based on the outcome of the evaluation require them to install best available retrofit technology. States were also required to establish Reasonable Progress Goals in SIPs to meet a 2064 goal of natural visibility conditions. The Regional Haze program is intended to be implemented through a series of ten-year plans developed by states and approved by the EPA. States were required to submit a second ten year plan in 2018, however, the EPA adjusted the submittal timeline to 2021.

Colorado adopted a second ten-year regional haze plan that does not require additional emission controls on Craig Station and incorporates retirement dates for Craig Station Units 1, 2, and 3. Colorado submitted its plan to the EPA and it is still under review. Arizona adopted a second ten-year plan that required additional emission reductions at Springerville Unit 3 but no new emission controls. EPA has issued a final rule to approve in part and disapprove in part the Arizona adopted plan.

We expect to work with TEP and the Arizona Department of Environmental Quality to address the plan deficiencies and make a final plan as workable as possible for implementation at Springerville Unit 3. Wyoming adopted a second ten year plan that did not require any further emission controls or any lower emission limits at Laramie River Generating Station. EPA issued a final rule to approve in part and disapprove in part the Wyoming-adopted plan. We expect to work with Basin and the Wyoming Department of Environmental Quality to address the plan deficiencies and make a final plan as workable as possible for Laramie River Generating Station.

Water Quality

The Clean Water Act. The Clean Water Act regulates the discharge of process wastewater and certain storm water to WOTUS under the NPDES permit program. This permit program is primarily relevant to our Colorado generating facilities. Colorado has been delegated NPDES permitting authority by the EPA and is therefore our primary water quality regulator in Colorado. Each of our generating facilities presently has the appropriate permits. Water quality regulations require us to comply with each state's water quality standards, including sampling and monitoring of the waters around affected facilities.

Clean Water Act permitting can also be required for the construction phase of projects. Disturbing over 1 acre of land requires construction stormwater general permits. We, or our contractor, regularly seek, obtain, and comply with these permits across our service territory. Section 404 of the Clean Water Act requires permits for the placement of dredged or fill material (e.g., soil and rock) in streams and wetlands. This permit program is primarily administered by the Corps and we regularly rely on various Corps general permits for construction projects.

The regulatory definition of WOTUS under the Clean Water Act and other federal statutes has been in flux for the past two decades due to U.S. Supreme Court decisions, and multiple rulemakings of the Corps and the EPA spanning the past three presidential administrations. In May 2023, the U.S. Supreme Court in *Sackett v EPA* found that federal jurisdiction over WOTUS only extends to "relatively permanent waters" and wetlands that directly abut/touch WOTUS. This decision substantially reduced federal Clean Water Act jurisdiction and the Corps and the EPA promptly revised their regulations to conform with the Sackett decision. Reduced federal jurisdiction increased state attention and some states in our service territory are developing regulatory programs to protect waterways no longer under federal jurisdiction. Colorado House Bill 24-1379 became law in 2024 and directed the Water Quality Control Division to develop new dredge and fill permit program regulations by December 31, 2025. We are participating in the stakeholder process to develop these regulations. Many of our construction activities in WOTUS are authorized by streamlined federal general permits. We anticipate needing fewer of these federal permits in the future due to the *Sackett* decision but recognize that we may see an increased future need for yet to-be-established state permits and approvals. Our facilities are generally located in arid and semi-arid regions where WOTUS and state waters are less numerous and of smaller size compared to wetter regions of the U.S. We have employed compliance methods that shield us from the uncertainty of fluctuating WOTUS definitions.

Spill Prevention Control and Countermeasures. The EPA issued regulations governing the development of Spill Prevention Control and Countermeasures plans. Many of our substation and generation sites are subject to these regulations and all Spill Prevention Control and Countermeasures plans meet the regulations.

Other Environmental Matters

Coal Ash. We manage coal combustion by-products such as fly ash, bottom ash and scrubber sludge by removing excess water and placing the by-products in land-based units in a dry form. At Craig Station, the combustion by-products are used for mine land reclamation at the adjacent coal mine. The mine-fill and landfills are regulated by state environmental agencies and all required permits are in place. We are meeting all compliance obligations under the final Coal Combustion Residual rule, and we are actively working to comply with the requirements of the new Legacy Rule (effective November 2024). We continue to analyze the final rule for potential impacts on our operations.

Global Climate Change Regulatory Developments Outside the Clean Air Act. Consideration of laws and regulations to limit emissions of greenhouse gases has been underway at the international, national, regional and state levels. International negotiations and agreements have historically determined what, if any, specific commitments to reduce greenhouse gas emissions the United States would make as a party to the Paris Agreement made under the United Nations Framework Convention on Climate Change. The new presidential administration has withdrawn the United States from the Paris Agreement and does not intend to participate in international environmental agreements on climate change that have "the potential to damage or stifle the American economy." The Paris Agreement did not directly dictate any particular emission reduction obligations for U.S. businesses and withdrawal from it is not expected to have a direct impact on our business operations.

Colorado and New Mexico have each adopted separate sets of requirements for the reduction of greenhouse gas emissions from fossil fuel-fired generating facilities. The RPS or RES adopted by each state are further discussed above. In recent years, Colorado adopted specific greenhouse gas emission reduction targets for the electric utility industry and economy wide targets. The Colorado legislature may consider additional emission reduction targets for electric utilities in its 2025 legislative session. Any new targets could require additional emission controls or the retirement of additional existing fossil fueled generating facilities, the building of additional renewable generation resources and the construction of new transmission facilities.

The Comprehensive Environmental Response, Compensation and Liability Act. CERCLA (also known as Superfund) requires cleanup of sites from which there has been a release or threatened release of hazardous substances and authorizes the EPA to take any necessary response action at Superfund sites, including ordering potentially responsible parties liable for the release to take or pay for such actions. Potentially responsible parties are broadly defined under CERCLA to include past and present owners and operators of, as well as generators of wastes sent to a site. To our knowledge, we are not currently subject to liability for any Superfund matters. However, we generate certain wastes, including hazardous wastes, and send certain of our wastes to third party waste disposal sites. As a result, there can be no assurance that we will not incur liability under CERCLA in the future.

Toxic Substances Control Act/Polychlorinated Biphenyls. We have limited quantities of PCBs in transmission equipment in the existing system. As oils are changed and systems replaced, PCBs are eliminated and PCB-free oils are used, reducing regulatory risk.

Per- and polyfluoroalkyl substances. There has been much recent federal and state activity surrounding a class of synthetic compounds known collectively as PFAS. This activity has occurred in both water and waste contexts, as well the consumer product phase-out context through Colorado legislation. We are monitoring ongoing regulatory and policy matters regarding PFAS and have replaced PFAS-containing fire suppression systems at our generating facilities with non-PFAS alternatives. Given the evolving regulatory environment and the widespread nature of PFAS in society and the environment, we continue to evaluate the relevance and extent of this topic to our operations.

Endangered Species Act. Compliance with the ESA can affect the cost and timing of our various activities including operation of existing facilities, and planning and permitting new or expanded facilities. The ESA can apply to us indirectly because it obligates federal agencies that are taking some form of permit, right-of-way, funding, or other action that we need. We regularly need federal permits and approvals from various agencies. The ESA also applies to us directly when our activities may "incidentally take" an ESA-listed species and there is no associated federal action. In February 2024, we enrolled in one program for the lesser prairie-chicken and applied to another for the monarch butterfly. Both provide incidental take regulatory coverage for covered activities. In December 2024, we finalized our enrollment in a voluntary monarch butterfly conservation program. The monarch butterfly was recently proposed for listing as a threatened species under the ESA.

Environmental groups frequently petition the USFWS to protect additional species and challenge regulatory and species listing decisions, which creates a dynamic regulatory environment. The USFWS identifies future species listings in a National Listing Workplan, which was updated in May 2024. We monitor the workplan for upcoming species listings that might affect our operations and plans. We are monitoring several species with workplan timing estimates in the next two years such as: little brown bat, western bumble bee, Suckley’s cuckoo bumble bee, western regal fritillary, and monarch butterfly. It is difficult to predict if and how these potential future species listings might affect our operations because the USFWS may decline to list certain species or may list species with regulatory provisions or guidance that reduces or eliminates restrictions on our activities.

ITEM 1A. RISK FACTORS

Our business, financial condition or results of operations could be materially adversely affected by various risks, including those described below.

Members and Regulatory Risks

Utility Member withdrawals, including, but not limited to, the final outcome of the contract termination payment amount proceedings and additional Utility Member withdrawals, may materially impact our financial condition, results of operations, long-term system resource planning, our long-term debt, our liquidity and our access to capital.

Pursuant to our Bylaws, a Member may withdraw from membership in us upon compliance with such equitable terms and conditions as our Board may prescribe provided, however, that no Member shall be permitted to withdraw until it has met all its contractual obligations to us. In 2021, FERC accepted our Board approved modified contract termination payment methodology, subject to refund, that included requirements for a two-year non-conditional notice and the payment of a contract termination payment. In December 2023, FERC issued an order on our contract termination payment methodology. We and United Power filed petitions for review of FERC's December 2023 order. See "BUSINESS — MEMBERS – Contract Termination Payment and Relationship with Members" and "Note 14—Commitments and Contingencies—Legal" to the Consolidated Financial Statements in Item 8 for further information.

United Power and MPEI withdrew from membership in us and paid us a contract termination payment. In 2024, LPEA and NRPPD provided us non-conditional notices to withdraw from membership in us. This was NRPPD's second non-conditional notice to withdraw. See "BUSINESS — MEMBERS – Contract Termination Payment and Relationship with Members." Although United Power and MPEI withdrew and paid us a contract termination payment, the methodology to calculate the contract termination payment remains subject to petitions for review and a pending compliance filing with FERC. Furthermore, the Membership Withdrawal Agreements with each of United Power and MPEI include provisions requiring a true-up once the final contract termination payment becomes non-appealable. While LPEA and NRPPD provided non-conditional notices to withdraw in 2024, there is no certainty that they will be able to pay the contract termination payment required upon withdrawal or will actually withdraw as they have asserted. NRPPD's failure to pay the contract termination payment arising out of its April 2022 non-conditional notice highlights the uncertainty of non-conditional notices from Utility Members to withdraw. This uncertainty makes long-term system resource planning difficult and makes it more expensive to plan and operate our business.

In addition, FERC's orders on calculating a contract termination payment for Utility Members served in the Eastern Interconnection, such as NRPPD, may not fully address the costs Basin may seek to impose on us upon the withdrawal of a Utility Member served in the Eastern Interconnection, and the proceedings related to Utility Members served in the Eastern Interconnection remain subject to a pending compliance filing at FERC, as well as the petitions for review. See "BUSINESS — MEMBERS – Contract Termination Payment and Relationship with Members" and "Note 14—Commitments and Contingencies—Legal" to the Consolidated Financial Statements in Item 8 for further information.

If United Power prevails in its petition for review, it may materially impact us. If FERC's contract termination payment methodology underestimates the monetary value of a Utility Member's obligation or a significant number of our Utility Members withdraw, it may materially impact us. If the contract termination payment for Utility Members served in the Eastern Interconnection does not address costs Basin may seek to impose upon us or result in full recovery of our costs, it may materially impact us. If negative conclusions about our financial condition, results of operations, long-term system resource planning and our long-term debt are drawn from any U.S. court of appeals orders or any subsequent FERC orders on the contract termination payment, it may materially impact us. If FERC subsequently revises the contract termination payment methodology that requires low payments by withdrawing Utility Members, refunds to Utility Members that withdrew, or additional credits to withdrawing Utility Members, it could materially impact us.

Although we view that a contract termination payment calculated based upon FERC's December 2023 order will not require us to offer prepayment of certain of our long-term debt, the contract termination payment methodology proceeding is on-going. In addition, our lenders may not agree that a calculation of a contract termination payment based upon FERC's orders on the contract termination payment does not require us to offer a prepayment of certain of our long-term debt.

The material impacts of some or all of the above items occurring could include a significant increase in rates to our remaining Utility Members, Utility Member unrest and desires to withdraw from our Utility Members, lawsuits related to withdrawals of Utility Members served in the Eastern Interconnection, a materially adverse effect on our financial condition and results of operations including our liquidity, an inability to issue additional secured debt under our Master Indenture, a material hindrance in our long-term system resource planning, credit ratings downgrades, and we may be required to offer a prepayment of certain of our long-term debt. In addition, an offer of prepayment or prepayment of certain of our long-term debt could be viewed by lenders as an event of default under the cross-default provision of certain of our loan agreements, including our 2022 Revolving Credit Agreement that provides backup for our commercial paper program. If such debt is accelerated due to the cross-default provision and we are unable to pay such accelerated debt, our lenders could assert that there is an event of default under our Master Indenture.

Resource planning and COPUC oversight, including regulatory requirements and our ability to cost-effectively implement our resource plan, may impact our financial condition and future plans.

In Colorado, we are required to file and obtain COPUC approval for our Electric Resource Plan. Approval of Phase I of our 2023 ERP that included our preferred IRA scenario and was related to our federal funding application under the New ERA Program became effective in September 2024. In September 2024, we commenced Phase II of our 2023 ERP to solicit and evaluate bids for new dispatchable, renewable, and storage resources with commercial operation dates between 2026-2031. See "BUSINESS — POWER SUPPLY RESOURCES – Resource Planning." If we are unable to implement the COPUC-approved portfolio resulting from Phase II of our 2023 ERP, including entering into the applicable agreements for these resources at the proposed prices, or if such resources do not achieve commercial operation on the proposed timeline, it may impact our financial condition, future plans, ability to comply with green house gas reduction requirements and RPS/RES obligations of our Utility Members, and may result in Utility Member unrest. If we are unable to or are delayed in receiving federal funding under the New ERA Program or government action restricts the disbursement of approved funds, the qualification of the New ERA Program or even the existence of the New ERA Program as contemplated in Phase I of our 2023 ERP or to adjust funding based upon the results of Phase II of our 2023 ERP, we may be required to seek alternative sources of funding for resources or it may increase the cost to implement our resource plan, including the costs of new resources and costs related to our stranded assets, or result in modification of our resource plan.

Other states in which we operate may also implement laws or regulations that require us to also file resource plans in their state or impact existing resources or future resource procurements. Multiple state resource plan requirements or generation limitations may lead to additional costs to comply with new requirements and impact our future plans.

The perceived competitiveness of our wholesale rates by our Utility Members and limitations on Utility Members' self-supply options could result in Utility Member unrest.

Our wholesale electric service contract requires each Utility Member to purchase and receive from us, and for us to deliver, all energy and capacity required for the operation of the Utility Member's system, as further modified by programs set out in tariffs filed with FERC. Each Utility Member may elect to provide up to 5 percent of its requirements from distributed or renewable generation owned or controlled by the Utility Member and Utility Members may also propose projects that they will own or control under our BYOR Program, subject to certain capacity limitations within that program. See "BUSINESS — MEMBERS." While the price and volatility for long-term wholesale electricity has increased in the past couple years and we believe will continue into the future, the perceived competitiveness of our wholesale rates and the limitations on Utility Member’s self-supply options by our Utility Members may result in Utility Member unrest.

If we are unsuccessful in keeping our wholesale rates to our Utility Members competitive or implementing increased flexibility for our Utility Members, we may experience Utility Member unrest and desires to withdraw, unfavorable media coverage, credit ratings downgrades, additional laws and regulations targeted at us, or other negative consequences which may impact our financial condition and future plans.

We are subject to rate regulation by FERC, and the outcome of the settlement and hearing procedures related to our new Class A-41 formula rate could have an adverse effect on our results of operations and financial condition.

Changes in the wholesale rate for our Utility Members must be approved by a majority of our Board and are also subject to FERC approval or acceptance. In May 2024, we filed with FERC a new Class A rate schedule (A-41) that uses a formula rate. In July 2024, FERC accepted our new A-41 formula rate, with an August 1, 2024 effective date, subject to refund. See "BUSINESS — RATE REGULATION." FERC set the matter for settlement and hearing. Settlement can extend for a substantial period of time and, if unsuccessful, a hearing schedule would be implemented that could take additional time and result in a review of all our expenses. During these periods, our A-41 formula rate is in place, subject to refund. Depending on the outcome of the settlement or hearing, we may be required to provide a refund of certain Utility Members' electric sales revenues and not recover underpayment from other Utility Members during this refund period. Any under recovery of revenue during this refund period may adversely affect our results of operations, financial position and cash flow. If a hearing occurs, our expenses may be subject to further challenge and we may be unable to recover certain expenses from our Utility Members.

In addition, our ability to create a regulatory asset or use regulatory liabilities in the future, including those associated with the early retirements of certain of our generating facilities to implement our 2023 ERP, requires FERC approval. If we are unable to obtain FERC approval, the cost of electric service we provide to our Utility Members could increase and, as a result, could affect their ability to perform their contractual obligations to us. In addition, we may experience Utility Member unrest and desires to withdraw from our Utility Members.

In addition to FERC's jurisdiction over our wholesale rates to our Utility Members, FERC also regulates our market-based rate authority and our transmission service rates. With the withdrawal of United Power and the addition of new renewable resources, our market-based rate authority in the WACM balancing authority area may be impacted. In our July 2024 filing with FERC of a change in status, we stated that we failed FERC's market share analysis in the WACM balancing authority area in just one of the four seasons. If we no longer have market-based rate authority in certain balancing authority areas, it could have an adverse effect on our results of operations and financial condition. If FERC were to require a reduction in our transmission service rates, it could have an adverse effect on our results of operations and financial condition. See "BUSINESS — RATE REGULATION."

Increased competition could reduce demand for our electric sales.

The electric utility industry has experienced increasing wholesale competition, enabled by deregulation, uneven implementation of regulatory obligations among wholesale power suppliers and revisions to existing regulatory policies, competing energy suppliers, including third party energy remarketing companies, new technology, and other factors. Competing energy suppliers are targeting our Utility Members by claiming to be able to offer lower priced and cleaner wholesale electric power. This includes assisting our former Utility Members in seeking to withdraw from membership in us and financing the withdrawal payment by our Utility Members. On the retail side, states in which our Utility Members' service territories are located do not have retail competition legislation. However, these states could enact retail competition legislation which could reduce our electricity demand from our Utility Members and the pool from which we recover fixed costs, resulting in higher rates to our Utility Members. Competing energy suppliers are also targeting the communities and tribes our Utility Members serve by claiming to be able to offer lower priced and cleaner wholesale electric power. It also includes assisting the communities and tribes our Utility Members serve by helping them create electric utilities or seek new power suppliers. In addition, federal legislation could mandate retail choice in every state.

We and our Utility Members are subject to regulations issued by FERC pursuant to PURPA with respect to matters involving the purchase of electricity from, and the sale of electricity to, qualifying facilities and co-generators. An increase in the number and/or size of qualifying facilities selling electricity to our Utility Members could reduce our electricity demand from our Utility Members.

We may face competition from qualifying facilities, other utilities, competing energy suppliers, and fuel sources, or as a result of technological innovations. Technological innovations may include methods or products that allow consumers to bypass the electric supplier, to switch fuels or to reduce consumption. These innovations may include, but are not limited to, demand response, distributed generation, energy storage and microgrids. Competition from other utilities and competing energy suppliers may consist of competition from other electric companies, helping our Utility Members withdraw from membership in us, annexations by municipalities, helping municipalities and tribes our Utility Members serve create electric utilities, and competition for the sale of excess power to non-members on both a short-term and long-term basis. If competition increases, additional Utility Members may withdraw, rates to our remaining Utility Members may increase or our financial condition and results of operations could be adversely affected.

Our Utility Members have a substantial number of industrial and large commercial customers who could decrease operations, shut down, or elect to self-generate in the future.

Based on the information available to us by our Utility Members, which is 2023 data in most cases and not independently verified by us, industrial and large commercial customers account for approximately 30 percent of our Utility Members' energy sales. A large percentage of these sales are in energy production, extraction and transportation. The 15 largest customers of our Utility Members, a substantial percentage of which are in energy production, extraction and transportation, total approximately 16 percent of the aggregate retail electric energy sales of our Utility Members, based on the same data from our Utility Members. High inflation and rising interest rates, an economic downturn, volatile energy and fuel prices, additional government restrictions imposed on extractive industries, or other changes in business conditions could affect the level of energy sales to our Utility Members' large commercial customers. Future sales to large commercial customers could decrease should these large commercial customers decide to decrease their operations, shut down operations, or elect to self-generate pursuant to changes in state law that could permit non-utility generation of power. In addition, weather has a significant impact on the amount of energy sales to our Utility Members' irrigation customers. Wetter weather results in less use of irrigation, driving decreased energy sales.

Our financial condition is largely dependent upon our Utility Members.

Our financial condition is largely dependent upon our Utility Members satisfying their obligations under their wholesale electric service contracts with us. In 2024, 84.9 percent of our revenues from electric sales were from our Utility Members. We do not control the operations of our Members, and their financial condition is not tied to our results of operations. Accordingly, we are exposed to the risk that one or more of our Utility Members could default in the performance of their obligations to us under their wholesale electric service contract. A default could result from financial difficulties of one or more Utility Members or because of intentional actions by our Utility Members. Our results of operations and financial condition could be adversely affected if a significant portion of our Utility Members default on their obligations to us, and such Utility Members' defaults could trigger an event of default under certain of our loan agreements.

High impact loads in our Utility Members' service territories could impact our financial condition and liquidity.

High impact loads that have large load requirements, including data centers, are approaching our Utility Members for service. Both the number and size of these high impact load requests are increasing and expected to further increase substantially with the growth of artificial intelligence and other factors, thereby potentially materially increasing our aggregate power requirements. The volume of these high impact load requests and uncertainty related to these requests create risks.

We cannot predict whether these high impact loads under consideration will ever commence operations, the size and duration of the power requirements of those that do become operational, and whether they will seek to be served by a power supplier other than our Utility Members. If we or our Utility Members are unable to serve these loads by the dates requested by these high impact loads, it may result in new legislation, such as retail competition, or changes to our Utility Members' certified service territories. Further, a material increase in our aggregate power requirements may impact our ability to comply with RPS/RES requirements and greenhouse gas reduction requirements.

Our cooperative business model is facing increasing challenges.

As a member-owned cooperative, we are facing increasing challenges to our cooperative business model. There are increasing challenges to our governance structure, the long-term nature of our wholesale electric service contracts, limitations in our wholesale electric service contracts in the amount of self-supply provided to our Utility Members, and our transition to a cleaner generation portfolio. We are also facing increasing regulatory oversight and the prospect of future laws and regulations that could change our governance structure and cooperative business model. If we are not able to address or mitigate these challenges, we may experience additional laws and regulations targeted at us, Utility Member unrest and desires to withdraw, credit ratings downgrades, unfavorable media coverage or other negative consequences which may impact our financial condition and future plans.

We may be held liable for the actions or omissions of our Members, despite the fact that we and our Members are separate legal entities and we do not own, operate, control or have the right to control our Members.

Litigation seeking to impose liability on us for the actions of our Utility Members have occurred. The plaintiffs in these actions have claimed that we are jointly liable for the actions of our Utility Members, including under theories of partnership, joint venture, joint/common enterprise, or alter ego. Although a jury determined in one case that we and one of our Utility Members do not operate as a joint venture or joint enterprise, there can be no assurance that a court or jury will determine in the future that we are not severally or jointly liable for the actions of our Members. Our results of operations and financial condition could be adversely affected if courts or juries determine we are severally or jointly liable for the actions of our Members.

Environmental and Legislative Risks

Compliance with existing and future environmental laws and regulations, including RPS/RES, may increase our costs of operation and further affect the utilization of current generating facilities, and satisfying asset retirement and environmental remediation obligations are significant.

As with most electric utilities, we are subject to extensive federal, state and local environmental requirements that regulate, among other things, air emissions, water discharges, land use, and the use and management of hazardous and solid wastes. Compliance requires significant expenditures for the installation, maintenance and operation of pollution control equipment, monitoring systems and other equipment or facilities, including the settlement of asset retirement obligations and expenses for environmental remediation obligations. Generally, existing environmental regulations are becoming increasingly stringent, including those related to greenhouse gas emissions or renewable or clean energy standards. The current federal administration is expected to bring a change in direction for environmental regulations. At this time, it is impossible to predict what changes in current regulations or new regulations or legislation may occur under the current federal administration.

The currently existing and any new federal, state or local environmental restrictions, including RPS/RES requirements and greenhouse gas reduction requirements imposed on our operations or our Utility Members, could result in significant additional costs, including capital expenditures. Implementation of regulations or more stringent standards may require us to modify the design or operation of existing facilities or purchase emission allowances. In addition, implementation of existing legislation and regulation or the imposition of more stringent standards or costs could further affect decisions regarding generating facility retirement and replacement, including the shutting down of additional generating facilities or the shutting down of individual coal-fired generating facilities earlier than scheduled, and may substantially increase the cost of electricity to our Utility Members. In 2024, our existing generating facilities generated approximately 39.6 percent of our energy available for sale, a substantial percentage of which is generated by coal-fired generating facilities. The cost impact of the implementation of regulation from existing legislation and future legislation will depend upon the specific requirements thereof and cannot be determined at this time, but could be significant, including increases in our operating expenses and potential stranded costs and investments in new generation and transmission. See "BUSINESS — ENVIRONMENTAL REGULATIONS" for additional information regarding environmental regulations.

The cost estimates for asset retirement and environmental remediation obligations are based upon information using various assumptions related to closure, post-closure and operating costs, the timing of future cash outlays, inflation and discount rates, and the potential compliance method. We continue to evaluate these obligations and make adjustments to these costs as needed.

Litigation relating to environmental issues, including claims of property damage or personal injury caused by greenhouse gas emissions, has increased generally throughout the U.S. Likewise, actions by private citizen groups to enforce environmental laws and regulations are becoming increasingly prevalent.

There can be no absolute assurance that we will always be in compliance with all environmental requirements or that we will not be subject to future or additional RPS/RES requirements or regulations related to greenhouse gas emissions. Failure to comply with existing and future requirements, even if this failure is caused by factors beyond our control, could result in civil and criminal penalties and could cause the complete, temporary or permanent shutdown of individual generating units not in compliance with these regulations.

We are subject to physical, operational and financial risks associated with weather, natural disasters and resource depletion impacts.

Weather and natural disasters can create physical, operational and financial risks. Physical risks include changes in weather conditions and an increase in extreme weather events. The energy needs of our Utility Members’ customers vary with weather. Changes in weather affected customers’ energy use, which could increase or decrease. Increased energy use due to weather changes may require us to invest in new generation and transmission. Decreased energy use due to weather changes may result in decreased revenues.

Weather and natural disasters may impact the economy, which could impact our sales and revenues. The price of energy has an impact on the economic health of our communities. The cost of additional regulatory requirements, such as regulation of greenhouse gas emissions, could impact the availability of goods and the prices charged by our suppliers that would normally be borne by consumers through higher prices for energy and purchased goods. To the extent financial markets view changes in weather and emissions of greenhouse gases as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions, including cost of capital. To the extent insurance markets view changes in weather and emissions of greenhouse gases as an insurance risk or elect not to insure generating facilities that have greenhouse gas emissions, it could negatively affect our ability to obtain insurance or cause us to obtain insurance with higher deductibles, higher premiums, lower insurable amounts, or more restrictive policy terms.

Our Utility Members' service territories are exposed to extreme weather, including extreme temperatures, high winds, thunderstorms, blizzards, drought, flooding, ice storms, and tornados. Drought, thunderstorms and high wind events and extreme temperatures can also contribute to wildfire impacts from extreme weather. These severe weather events can physically damage our facilities and our Utility Members' facilities. Any such occurrence can disrupt the ability to deliver energy and can increases costs. Extreme weather can also reduce usage and demand for energy of our Utility Members' customers and could result in us incurring obligations to third parties related to such events. These factors could negatively impact our operations, financial conditions and cash flow.

To the extent the frequency of extreme weather or extreme weather related events increases, this could increase our cost of providing service to our Utility Members. Periods of extreme temperatures could impact our ability to meet demand. With our increasing renewable generation portfolio, increased uncertainty and variability in weather could impact generation from our renewable facilities and the costs to serve our Utility Members. Changes in precipitation resulting in droughts or water shortages could adversely affect our operations. Drought conditions in the western part of the U.S., especially in the southwest U.S., may continue to impact the water levels at reservoirs used by WAPA to supply us hydroelectric-based power and may result in further reduction in the amount of capacity and energy allocated from WAPA, which may be material, and may further increase the cost of such to us. This could require us to purchase power to serve our Utility Members and/or reduce our ability to sell excess power on the wholesale market and reduce revenues. Drought conditions or actions taken by the court system, regulators, or legislators could also limit our supply of water, which could adversely impact operations of our generating facilities, cause early retirement of generating facilities and increase the cost for energy. Drought conditions also contribute to the increase in wildfire risk from our facilities. While we carry liability insurance, given an extreme event, if we are found to be liable for wildfire damages, amounts that potentially exceed our coverage could negatively impact our results of operations, financial condition and cash flow.

Our business, financial condition, results of operations and prospects could be materially adversely affected by new or revised laws, regulations or executive orders, as well as by regulatory action or inaction.

Our business could be materially adversely affected by a variety of legal activity, such as: (a) the adoption of new or revised laws, regulations and interpretations; (b) constitutional ballot or regulatory initiatives, such as those seeking deregulation or restructuring of the energy industry; (c) new or revised regulations, such as those affecting the emissions, water consumption, water discharges, wetlands, generation or transmission infrastructure operations, and environmental and other permitting requirements for energy infrastructure projects; (d) actions taken, or not taken, by government agencies as a result of executive orders, such as failing to issue, delaying the issuance of, or increasing the requirements necessary to obtain approvals, approving rates; and (e) changes in the way government interprets or applies laws, regulations and orders. Changes in the nature of the regulation of our business through this type or other types of legal activity could have a material adverse effect on our business, financial condition, results of operations and prospects. We are unable to predict future legislative, regulatory or executive action or inaction, including through constitutional ballot initiatives or changed government interpretations or applications, although any such changes may increase costs, which could have a material adverse effect on our business, financial condition, results of operations and prospects.

The structure of the energy industry and regulation in the U.S. is currently, and may continue to be, subject to challenges and restructuring proposals. Additional regulatory approvals may be required due to changes in law or for other reasons.

Operating Risks

Early retirements of our existing generating facilities may impact reliability for our Utility Members.

The early retirement of our former and existing generating facilities, including Craig Station and Springerville Unit 3, may impact our ability to deliver reliable electric power to our Utility Members. Early closure of existing generating facilities will result in us having less excess capacity, will make us more reliant upon our remaining dispatchable generating facilities and renewable resources, even with our plans for an additional natural gas-fired dispatchable generating facility and energy storage resources. If a material unexpected cost or breakdown at an existing generating facility to be closed early occurs, we may determine it is more economical to close the facility even earlier than further invest in a generating facility scheduled for early retirement. With the addition of more intermittent renewable resources, we may have increased reliability risk especially during extreme weather events that may impact the supply of natural gas to our natural gas-fired generating facilities, the operation of our transmission system and the delivery of electric power to our Utility Members. With our increasing renewable generation portfolio, increased uncertainty and variability in weather could impact generation from our renewable facilities.

Increased reliability risk could have the effect of increasing the cost of electric service we provide to our Utility Members and have an adverse effect on our results of operations. In addition, we may experience Utility Member unrest and desires to withdraw from our Utility Members.

We may experience transmission constraints or limitations to transmission access, and our ability to construct, and the cost of, additional transmission is uncertain.

We currently experience periodic constraints on our transmission system and those of other utilities used to transmit energy from our remote generators due to periodic maintenance activities, equipment failures and other system conditions. We manage these constraints using alternative generation dispatch and energy purchasing patterns. The long-term solution for reducing transmission constraints can include joining a regional transmission organization, purchasing additional wheeling service from other utilities, or construction of additional transmission lines which would require significant capital expenditures.

We are increasing our renewable portfolio, and as other utilities are also increasing their renewable portfolios, the addition of renewable resources is increasing the demand for access to existing transmission lines, making it difficult for us to acquire transmission capacity, and we expect it will be necessary for us to construct or pay for additional transmission lines. Although we expect to participate in the expansion of SPP's regional transmission organization into the Western Interconnection in 2026, there is no certainty this expansion will occur on time or that the SPP market will improve the transmission constraints or limitations to transmission access.

In most cases, construction of transmission lines presents numerous challenges. Environmental and state and local permitting and siting processes may result in significant inefficiencies and delays in construction. The timing needed to acquire land rights may also be lengthy. These issues are unavoidable and are addressed through long-term planning. We typically begin planning new transmission at least 10 years in advance of the need and voluntarily participate in regional and interregional transmission planning and cost allocation discussions with neighboring transmission providers. In the event that we are unable to complete construction of planned transmission expansion, we may be unable to implement aspects of our 2023 ERP, we may need to rely on purchases of market-priced electric power, which could put increased pressure on electric rates. We may also experience Utility Member unrest.

Losses from wildfires could adversely affect our financial condition, future results of operations, and cash flow.

We have ownership or capacity interests in approximately 5,819 miles of transmission lines, including transmission lines that cross through certain wildfire prone areas such as forest areas and grasslands. Certain of our transmission facilities are located on federal land and certain permits with the federal government impose strict liability on us up to a maximum cap related to our transmission facilities. If a wildfire involving our transmission facilities were to occur, we could be liable for property damage, costs of fire-fighting activities, and other costs, for which liability could be substantial and in excess of our liability insurance. We may also be subject to credit ratings downgrades, unfavorable media coverage or other negative consequences which may impact our financial condition and future plans. In addition, the availability of liability insurance may decrease, and the insurance that we are able to obtain may have higher deductibles, higher premiums, lower insurable amounts, or more restrictive policy terms. Any such liability could materially affect us and our financial condition, future results of operations, and cash flow.

We could be adversely affected if we or third parties are unable to successfully operate our facilities.

Our performance depends on the successful operation of our facilities. Operating facilities involves many risks, including, among others:

- operator error and breakdown or failure of long lead-time equipment or processes;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- labor disputes;
- problems resulting from an aging workforce and retirements;
- the ability to maintain and retain a knowledgeable workforce;
- work slowdown or stoppages due to communicable diseases or other factors;
- availability and cost of equipment and fuel;
- supply chain interruptions, including transportation interruptions;
- availability and cost of water;
- water supply interruptions;
- extreme weather events, including high or low temperatures, severe thunderstorms, drought, and wildfires;
- catastrophic events, such as fires, earthquakes, explosions, floods or other similar occurrences; and

- compliance with mandatory reliability standards when such standards are adopted and subsequently revised.

Unforeseen outages at our generating facilities or transmission facilities could lead to higher costs because we may be required to purchase power in volatile electric power markets. With the closures of our generating facilities and planned closure of additional generating facilities, the unforeseen outages of one or more of our remaining generating facilities may have a greater impact on us and lead to service outages and business interruptions, which could negatively impact our business and operations. A decrease or elimination of revenues from electric power produced by our generating facilities or an increase in the cost of operating the facilities could adversely affect our results of operation.

We are exposed to uncertainty in connection with construction projects at new and existing generating facilities, third party generating facilities related to our long-term power purchase contracts, and new and existing transmission facilities, and in connection with decommissioning of certain existing facilities.

Our existing facilities require ongoing capital expenditures in order to maintain efficient and reliable operations. Many of our generating facilities were constructed over 40 years ago and, as a result, may require significant capital expenditures to maintain efficiency and reliability and to comply with changing environmental requirements. In 2024, we executed engineering, procurement and construction contracts for two solar-based facilities totaling 255 MWs that are expected to achieve commercial operation in 2025. Based upon Phase I of our 2023 ERP that is subject to change based upon Phase II of our 2023 ERP, we expect to add a new natural gas-fired generating facility and new energy storage resources. We also upgrade and build new transmission facilities to maintain reliability, for load growth, or for the accommodation of new generation. In the years 2025 through 2027, we estimate that we may invest approximately $1.46 billion in new facilities and upgrades to our existing facilities.

Based upon our 2023 ERP, we also expect to enter multiple long-term power purchase contracts with third parties for new generating facilities. As part of our BYOR Program, a Utility Member will own or control a new generating facility and enter into an agreement with us enabling us to purchase the output of such facility.

The completion of construction projects is subject to substantial risks, including delays or cost overruns due to:

- shortages and inconsistent quality of equipment, materials and labor;
- siting, permits, approvals and other regulatory matters;
- unforeseen engineering problems;
- work slowdown or stoppages due to communicable diseases or other factors;
- environmental, cultural and geological conditions;
- environmental litigation;
- delays or increased costs to interconnect our facilities with transmission grids;
- increased costs due to inflation or tariffs;
- governmental regulations and tariffs, including for solar panels;
- unanticipated increases in cost of materials and labor and supply chain interruptions; and
- performance by engineering, construction or procurement contractors.

An important financial aspect of constructing our new owned renewable and energy storage resources, including the two solar-based facilities totaling 255 MWs that are expected to achieve commercial operation in 2025, is us receiving either investment tax credits or production tax credits, along with direct pay as provided in the IRA. If we do not qualify for all or some of the credits or direct pay either due to late construction, failure to comply with the requirements to obtain such, or changes in law, it is expected to negatively impact the economics of these projects and increase the cost of electric service we provide to our Utility Members.

The early retirement and decommissioning of certain of our existing generating facilities, including Craig Station and Springerville Unit 3, and the Colowyo Mine is subject to substantial risks. In addition, the early retirement and decommissioning of additional existing generating facilities and the transition to full reclamation for the Colowyo Mine in 2025 is subject to substantial risks, including potential requirements to recognize a material impairment of our assets and incur added expenses relating to accelerated depreciation and amortization, decommissioning, reclamation and cancellation of long-term contracts for such generating plants and facilities. The closure of Springerville Unit 3 is also subject to the risk of obtaining agreements with the applicable parties and with reasonable terms. Closure of any of such generating facilities may force us to incur higher costs for replacement capacity and energy, will make us more reliant upon our remaining generating facilities, and cause us to have less excess capacity. The decommissioning costs may exceed our estimate, which could negatively impact our results of operations and liquidity. Furthermore, our ability to create a regulatory asset to defer expenses associated with certain early retirements or the utilization of regulatory liabilities requires FERC approval.

All of these risks could have the effect of increasing the cost of electric service we provide to our Utility Members and, as a result, could affect their ability to perform their contractual obligations to us. In addition, we may experience Utility Member unrest and desires to withdraw from our Utility Members.

We rely on purchases of electric power from other power suppliers and long-term agreements to purchase and transport fuels and to sell electricity we generate, which exposes us to market and counterparty risks.

Our electric power supply strategy relies, in part, on purchases of electric power from other power suppliers. In 2024, purchased power provided 60.4 percent of our energy requirements. These purchases consist of a combination of purchases under long-term agreements and short-term market purchases of electric power. Based upon Phase I of our 2023 ERP, we expect to enter into additional renewable power purchase contracts. As part of our BYOR Program, we expect to enter into agreements with our Utility Members to purchase the output of additional generating facilities. We also rely on long-term agreements with third parties to (a) manage our supply and transportation of fuel for our generating facilities, and (b) sell electricity we generate to non-member utilities. We are exposed to the risk that counterparties to these long-term agreements will breach their obligations to us or claim that we are in breach. We are exposed to the risk that bidders to our requests for new resources will not honor their bids requiring us to use an alternative bid or restart the process. We are also exposed to the risk that counterparties to our renewable power purchase contracts and engineering, procurement, and construction contracts will be unable to construct the renewable generating facilities by the time specified in the respective contract or at all. If this occurs, we may be forced to enter into alternative contractual arrangements or enter into short-term market transactions at then-current market prices. Purchasing electric power in the market exposes us, and consequently our Utility Members, to market price risk because electric power prices can fluctuate substantially over short periods of time. The terms of these new arrangements may be less favorable than the terms of our current agreements, which could have an adverse effect on our results of operations.

When we enter into long-term power purchase contracts, we rely on models based on our judgments and assumptions of factors such as future demand for electric power, future market prices of electric power and the future price of commodities used to generate electricity. These judgments and assumptions may prove to be incorrect. As a result, we may be obligated to purchase electric power under long-term agreements at a price which is higher than we could have obtained in alternative short-term arrangements. Conversely, our reliance on short-term market purchases exposes us to increases in electric power prices.

Our long-term power purchase contracts include contracts with WAPA and Basin, consisting of 13.1 percent and 15.7 percent, respectively, of our Utility Member energy sales in 2024 (in MWhs). We experience favorable pricing terms under our WAPA contracts under federal laws that give preference to federal hydropower production to "preference" customers, including cooperatives. If the federal laws under which we receive favorable pricing were to be amended or eliminated, if WAPA were to no longer provide us with power or favorable pricing for any other reason, or we were required to assign some or all of our power from WAPA to a third party, we would have to pay significantly higher prices to obtain this electric power, which could have an adverse effect on our results of operations. The prices we pay for power under the WAPA and Basin contracts are determined by WAPA and Basin, respectively, and are subject to change in accordance with the terms of the contracts and certain FERC approval. If we would have to pay significantly higher prices under these contracts, it could have an adverse effect on our results of operations.

We are exposed to risks related to our participation in organized markets that could have an adverse effect on our operations.

We currently participate in both the SPP and CAISO imbalance markets and expect to participate in the expansion of SPP's regional transmission organization into the Western Interconnection in 2026. Our participation in these organized markets causes increased ramping of our generating facilities resulting in increased strain on our generating facilities and operating costs. We will also be subject to additional risks related to our participation in SPP's regional transmission organization including costs allocation for transmission facilities built by others and allocation of losses caused by defaults of other participants in this market. In addition, the rules governing SPP may change from time to time and such changes could impact our costs and revenue.

Volatile natural gas prices could have an adverse effect on the operation of our facilities and our cost of electric service.

The wholesale electricity price generally correlates with the wholesale natural gas price in most regions of the U.S. Generally, low gas prices correlate to low wholesale electricity prices and could thereby reduce the competitiveness of our coal-fired generating facilities. Low natural gas prices could negatively impact the economics of operating our coal-fired generating facilities, which could cause the temporary or permanent shutdown of individual coal-fired generating facilities, including the shutting down of individual coal-fired generating facilities earlier than scheduled, thereby significantly increasing the cost of electric service we provide to our Utility Members and affecting their ability to perform their contractual obligations to us. High natural gas prices could increase the cost of operating our natural gas-fired generating facilities and the price of short-term market purchases and energy imbalance charges from other utilities, thereby significantly increasing the cost of electric service we provide to our Utility Members and affecting their ability to perform their contractual obligations to us.

We are subject to supply chain and commodity risks that could impact the timing of construction and the cost of additional facilities and the operation of our existing facilities.

A significant disruption in the global supply chain for the procurement and delivery of equipment for the construction of additional facilities, including transmission facilities, and operation of our existing facilities, along with workforce availability, commodity pricing, tariffs and inflation, could impact the timing and costs of the construction and operation of our facilities. We many need to seek alternative supply at potentially higher costs, which could impact our ability to construct additional facilities and delivery of power to our Utility Members, which could have an adverse effect on future revenues and costs, which could be material. In addition, it could require us to operate other generating facilities at higher cost or pay significantly higher prices to obtain electric power from other sources, which could have an adverse effect on our results of operations.

We may not be able to obtain an adequate supply of fuel, which could limit our ability to operate our facilities.

We obtain our fuel supplies, including coal, natural gas and oil, from a number of different suppliers, including mines that we own. Any disruptions in our fuel supplies, including disruptions due to weather, rail transportation, labor relations, communicable diseases, permitting, regulatory matters, environmental regulations, or other factors affecting our coal mines or fuel suppliers, could result in us having insufficient levels of fuel supplies. As we are transitioning full reclamation at Colowyo Mine in 2025 prior to the retirement of Craig Station, if we do not have sufficient inventory to operate Craig Station or sell coal to third parties as required by existing agreements, it may impact our operation of Craig Station and subject us to damages. Inventory shortages could occur in the future due to any of the disruptions described above. Natural gas and oil supplies can also be subject to disruption due to operational issues, natural disasters, extreme weather, and other events. Any failure to maintain an adequate inventory of fuel supplies could require us to operate other generating facilities at higher cost or pay significantly higher prices to obtain electric power from other sources, which could have an adverse effect on our results of operations.

Financing Risks

We have a substantial amount of indebtedness and we expect this amount to increase significantly.

As of December 31, 2024, we had total debt outstanding of approximately $3.0 billion, of which approximately $2.8 billion was secured under our Master Indenture. We have incurred indebtedness primarily to construct, acquire, or make capital improvements to generation and transmission facilities to supply the current and projected electricity requirements of our Utility Members and to meet our other long-term electricity supply obligations. Additionally, we expect to incur substantial indebtedness in the future, and we forecast that we will have approximately $3.8 billion of total debt outstanding in 2027. If this occurs, we may be required to raise our rates, revise our plans for capital expenditures and/or restructure our long-term commitments. These actions may adversely affect our operations, and we may be unable to generate sufficient additional revenue to pay our obligations. Further, failure to meet the ECR requirement in our Master Indenture or failure to service the indebtedness secured by our Master Indenture would result in an event of default under our Master Indenture and other loan agreements. Consequently, our results of operations, liquidity and financial condition could be adversely affected.

We are constructing, and expect we will need to construct or acquire, additional generation and transmission facilities to meet our Utility Members' demands, to comply with new greenhouse gas reduction and RPS/RES requirements, and to implement our Electric Resource Plan, which may require substantial additional capital expenditures that will significantly increase our long-term debt, or for which we may not be able to obtain financing, and may result in development uncertainties for our business.

In the years 2025 through 2027, we estimate that we may invest approximately $1.46 billion in new facilities and upgrades to our existing facilities. We expect to incur significant indebtedness in connection with this capital expenditure program. The specific projects we undertake and the amount of such investments are subject to uncertainties and may be influenced by many factors, including:

- the forecasted electric demand of our Utility Members, which is impacted by our BYOR Program, demand response, high impact loads and Utility Members' withdrawals;
- availability and cost of power purchase options;
- changes in our 2023 ERP after Phase II is completed;
- our membership in a regional transmission organization;
- receipt of federal funding under the New ERA Program; and
- regulatory approvals and changes.

Any construction program would require substantial additional capital, requiring us to obtain financing resulting in a significant increase in the amount of our long-term debt. A significant increase in long-term debt may increase the cost of the electric service we provide to our Utility Members. Failure to obtain financing may adversely affect our results of operations, liquidity and financial condition.

Our ability to access short-term and long-term capital and our cost of capital could be adversely affected by various factors, including credit ratings and current market conditions, and significant constraints on our access to capital could adversely affect our financial condition and future results of operations.

We rely on access to short-term and long-term capital for construction of new facilities and upgrades to our existing facilities, and as a significant source of liquidity for capital expenditures not satisfied by cash flow generated from operations. In the years 2025 through 2027, we estimate that we may invest approximately $1.46 billion in new facilities and upgrades to our existing facilities which we expect will require us to take on significant additional long-term debt.

Our access to capital could be adversely affected by various factors, and certain market disruptions could constrain, at least temporarily, our ability to maintain sufficient liquidity and access capital on favorable terms, or at all. These factors and disruptions specific to us include:

- our credit ratings being downgraded;
- financial markets' view of our relationship with our Utility Members and the withdrawal of Utility Members, including FERC's and a court's order on the contract termination payment methodology;
- challenges or delays related to wholesale rate changes for our Utility Members;
- our wholesale electric service contracts with our Utility Members only extending through 2050 that may limit the length of future financings and our receipt of certain federal funding under the New ERA Program; and
- financial markets' view of our clean energy transition and the timing and progress of such transition.

Other factors and disruptions that may impact our access to capital include:

- market conditions generally;
- economic downturn or recession;
- instability in the financial markets;
- market pressures, including tightening of lending standards, and/or internal bank balance sheet constraints that could prevent and/or lower our lenders' commitments to financings;
- the overall health of the energy industry and the generation and transmission cooperative sector;
- negative events in the energy industry, such as wildfires or a bankruptcy of an unrelated energy company;

- war or threat of war; and
- cyberattacks, terrorist attacks or threatened attacks on our facilities or the facilities of unrelated energy companies.

If our ability to access capital becomes significantly constrained for any of the reasons stated above or any other reason, our ability to finance ongoing capital expenditures required to maintain existing facilities and to construct future facilities could be limited, our interest costs could increase and our financial condition and results of operations could be adversely affected.

If our receipt of federal funding under the New ERA Program is significantly delayed, the standards to receive funding under the New ERA Program are changed through congressional or executive action, the New ERA Program is terminated through executive orders, we receive less funding under the New ERA Program or we do not receive federal funding, we may have to seek alternative financing which could be at terms not as favorable as those of the New ERA Program such as interest rates could be significantly higher than under the New ERA Program and it may increase our costs of our resource plan as part of our 2023 ERP. This may result in higher rates to our Utility Members and Utility Member unrest.

We are exposed to market risks including economic downturns or recessions and instability in the financial markets, which could lead to changes in interest rates and availability of capital in credit markets. The interest rates on future borrowings could be significantly higher than interest rates on our existing debt. As of December 31, 2024, we had $593.5 million of debt with variable rates. The rates on this debt could increase.

We maintain the 2022 Revolving Credit Agreement which provides backup for our commercial paper program. The facility includes a letter of credit sublimit and a commercial paper backup sublimit, and financial covenants for DSR and ECR requirements consistent with the covenants in our Master Indenture. Failure to maintain these financial covenants or other covenants could preclude us from issuing commercial paper or from issuing letters of credit or from borrowing under the 2022 Revolving Credit Agreement.

We must make long-term decisions involving substantial capital expenditures based on current projections of future conditions.

Our decisions to meet our Utility Members' load demands by construction of new facilities, by entering into long-term power purchase contracts, or by relying on short-term power purchase markets are based on long-term forecasts. We rely on our forecasts to predict factors affecting our Utility Members' load demands such as economic conditions, population increases and actions by others in the development of generation and transmission facilities. Even though forecasts are less reliable the farther into the future they extend, we must make decisions based on forecasts that extend decades into the future due to the long-term nature of power purchase contracts, the long lead time necessary to develop and construct new facilities, and the long-term expected useful life of those facilities.

In 2024, LPEA and NRPPD provided us non-conditional notices to withdraw from membership in us. See "BUSINESS — MEMBERS – Contract Termination Payment and Relationship with Members." While LPEA and NRPPD have provided notices to withdraw, there is no certainty that they will actually withdraw as they have asserted. This uncertainty makes long-term forecasting difficult. Additional Utility Members may also seek to withdraw.

Our Board has established a BYOR Program that was accepted by FERC. While there are projects that total 330 MWs that are still proceeding through our inaugural BYOR Program cycle, there is no certainty that these projects will achieve commercial operation. This uncertainty makes long-term forecasting difficult.

Our forecasts and actual events may vary significantly, and, as a result, we may rely on technology that becomes less competitive, install transmission facilities in areas where they are not needed, or we may not develop the appropriate number or type of generating facilities. If we over-estimate the growth in our Utility Members' demand such as high impact loads, the BYOR Program or Utility Members' withdrawal, there is no assurance that the price of surplus power or energy from surplus resources would be economical or could be sold without a loss. If we underestimate the growth in our Utility Members' demand, the BYOR Program or Utility Members' withdrawal, we may be required to purchase power or energy at a cost substantially above the cost we would have incurred to obtain the power or generate the energy from owned facilities.

We are subject to risks associated with our ability to obtain adequate insurance at acceptable costs.

The financial condition of some insurance companies, actual or threatened physical attacks or cyberattacks, natural disasters, wildfire losses, and views on changes in weather and emissions of greenhouse gases, among other things, could have disruptive effects on insurance markets. The availability of insurance may decrease or be completely unavailable, and the insurance that we or the operators of our facilities are able to obtain may have higher deductibles, higher premiums, lower insurable amounts, or more restrictive policy terms. These issues could be viewed by lenders as triggering an event of default under certain provisions of certain of our loan agreements if a waiver or amendment cannot be obtained. Further, the insurance policies may not cover all of the potential exposures or the actual amount of loss incurred.

Any losses not covered by insurance, or any increases in the cost of applicable insurance, could adversely affect our results of operations, financial condition and cash flow.

General Risks

Cybersecurity threats are increasing and if we are unable to protect our information systems, our operations could be disrupted and our financial condition could be adversely affected.

We operate in a highly regulated industry that requires the continued operation of advanced information technology systems and network infrastructure. We rely on networks, information systems and other technology, including the Internet and third party hosted servers, to support a variety of business processes and activities. We use information systems to process financial information and results of operations for internal reporting purposes and to comply with regulatory financial reporting, legal and tax requirements. We own assets deemed as critical infrastructure, the operation of which is dependent on information technology systems. Further, the computer systems that run our facilities are not completely isolated from external networks. Our generation and transmission assets and information technology systems, or those of our jointly owned plants, could be directly or indirectly affected by deliberate or unintentional cyber incidents. There appears to be an increasing level of activity, sophistication, and maturity of threat actors, in particular nation state actors, that wish to disrupt the U.S. bulk power system. Such parties could view our computer systems, software, or networks as attractive targets for cyberattack. For example, malware has been designed to target software that runs the nation’s critical infrastructure such as power transmission grids. These incidents may be caused by failures during routine operations such as system upgrades or user errors, as well as network or hardware failures, malicious or disruptive software, computer hackers, rogue employees or contractors, cyberattacks by criminal groups or activist organizations, ransomware, geopolitical events, natural disasters, failures or impairments of telecommunications networks, or other catastrophic events. In addition, such incidents could result in unauthorized disclosure of material confidential information, including personally identifiable information.

In addition, in the ordinary course of business, we collect and retain sensitive information, including personally identifiable information about employees, directors, and other third parties, and other confidential information. In some cases, administration of certain functions are outsourced to third-party service providers that could also be targets of cyberattacks.

If our technology systems are breached or otherwise fail, we may be unable to fulfill critical business functions, including the operation of our generation and transmission assets, our ability to collect revenue, and our ability to effectively maintain certain internal controls over financial reporting. Further, our generation assets rely on an integrated transmission system, a disruption of which could negatively impact our ability to deliver power to our Utility Members. Our collection of revenue from our Utility Members relies upon our Utility Members' ability to collect revenue from their customers, a disruption of which or cybersecurity attack on our Utility Members could negatively impact us. Our Utility Members have their own independent cybersecurity programs and procedures. A major cyber incident could result in significant business disruption, compromised or improper disclosure of data, and expenses to repair security breaches or system damage and could lead to litigation, regulatory action, including penalties or fines, and an adverse effect on our financial condition, results of operations, and reputation. Moreover, the amount and scope of insurance maintained against losses resulting from any such cyber incident may not be sufficient to cover losses or otherwise adequately compensate for any disruptions to business that could result. In addition, as cybercriminals become more sophisticated, the cost of proactive defensive measures may increase.

Failure to attract and retain a qualified workforce could have an adverse effect on our business.

Our business is dependent on our ability to attract, train, and retain employees representing diverse backgrounds, experiences, and skill sets. The competition for talent has become increasingly intense and we may experience increased employee turnover due to this tightening labor market and challenges to attract a qualified workforce, especially with specialized knowledge. Specialized knowledge is required of our technical employees for construction and operation of facilities. This may pose additional difficulty for us as we work to recruit, retain, and motivate employees in this climate, while maintaining a work environment that enables all our employees to thrive. Failure to hire and adequately train and retain employees, including the transfer of significant historical knowledge and expertise to new employees, or future availability and cost of contract labor, may adversely affect our results of operations, financial position and cash flow.

We may be subject to physical attacks.

As operators of energy infrastructure, we are facing heightened risk of physical attacks on our electric systems. Our generation and transmission assets and systems are geographically dispersed and are often in rural or sparsely populated areas which make them especially difficult to adequately detect, defend from, and respond to such attacks. Recent physical attacks on other electric utilities in the U.S. and the coverage of such attacks by the media has further increased this risk and the risk of copycat attacks.

If, despite our security measures, a significant physical attack occurred, we could have our operations disrupted, property damaged, experience loss of revenues, response costs, and other financial loss; and be subject to increased regulation, litigation, and damage to our reputation, any of which could have a negative impact on our business and results of operations.

A portion of our workforce is represented by unions. Failure to successfully negotiate collective bargaining agreements, strikes or work stoppages could cause our business to suffer.

Many of our employees are covered by collective bargaining agreements, and other employees may seek to be covered by collective bargaining agreements. Our current collective bargaining agreements expire in April 2029. Strikes, work stoppages or other business interruptions could occur if we are unable to renew these agreements on satisfactory terms, enter into new agreements on satisfactory terms or otherwise manage changes in, or that affect, our workforce, which could adversely impact our business, financial condition and results of operations. The terms and conditions of renegotiated or new collective bargaining agreements could also increase our costs or otherwise affect our ability to fully implement future operational changes to enhance our efficiency or to adapt to changing business needs or strategy.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

We have a comprehensive cybersecurity program designed to protect and preserve the confidentiality, integrity and availability of our data and systems. We are also subject to mandatory cybersecurity regulatory requirements. Our risk management programs, which address both enterprise and energy commodity risks, provides for evaluating and addressing cybersecurity risks and cybersecurity compliance. As part of our evaluation of cybersecurity risks, we consider cybersecurity risks and threats related to use of third-party service providers. Depending on the third-party service provider, the services provided by such third party and the data stored or to which such third party has access, we require different cybersecurity protections and specific cybersecurity programs that the third party must maintain. Our Utility Members have their own independent cybersecurity programs and procedures.

Cybersecurity risks with long-term resolutions are evaluated and added to our risk register, which is reviewed and updated by a corporate committee quarterly. This corporate committee, consisting of senior executives and support staff, meets regularly to assess enterprise, including cybersecurity, and energy commodity risks. Our Chief Administrative Officer/CHRO manages our information technology department and has executive oversight of our cybersecurity program. Our Chief Information and Technology Officer and Chief Information Security Officer that report directly or indirectly to our Chief Administrative Officer/CHRO are responsible for implementation of our cybersecurity program. As of December 31, 2024, our Chief Information and Technology Officer and Chief Information Security Officer maintained multiple cyber-related certifications from nationally recognized organizations.

We interface regularly with a wide range of external organizations and participate in classified briefings to maintain an awareness of current cybersecurity threats and vulnerabilities. We utilize third-party consultants to evaluate and test our cybersecurity preparedness and participate in national transmission grid security exercises that also address cybersecurity threats. Our security efforts are intended to address evolving and changing cyber threats. We operate a dedicated cyber security center with capabilities to monitor, detect, analyze, mitigate, and respond to cyber threats.

The Engineering and Operations Committee of our Board has oversight of our cybersecurity program and the risks from cybersecurity threats. The Engineering and Operations Committee is briefed quarterly with both oral and written reports on cybersecurity including cybersecurity risks. Our Board receives oral briefing on cybersecurity including cybersecurity risks no less than once per year and our Board is provided access to all written reports provided to the Engineering and Operations Committee.

We are subject to numerous cybersecurity threats and the cybercriminals are becoming more sophisticated and are increasingly targeting electric utilities. A major cyber incident could result in significant business disruption, compromised or improper disclosure of data, and expenses to repair security breaches or system damage and could lead to litigation, regulatory action, including penalties or fines, and an adverse effect on our financial condition, results of operations, and reputation. See "RISK FACTORS – General Risks" for additional information. While there have been immaterial incidents such as phishing and attempted financial fraud across our system, there has been no material impact on business or operations from these attacks. However, we cannot guarantee that security efforts will prevent breaches, operational incidents, or other breakdowns of information technology systems and network infrastructure and cannot provide any assurance that such incidents will not have a material adverse effect in the future.

ITEM 2. PROPERTIES

Generating Facilities

We own, lease or have undivided percentage interests in various generating facilities which are identified in the table below. All of our interests in these facilities or agreements, as applicable, are subject to the lien of our Master Indenture.

Name	Location	% Interest Owned or Leased	Fuel Used	Unit Rating (MW)*	Our Share (MW)*	Year Installed
Coal						
Craig Generating Station Unit 1	Colorado	24.0	Coal	427	102	1980
Craig Generating Station Unit 2	Colorado	24.0	Coal	410	98	1979
Craig Generating Station Unit 3	Colorado	100.0	Coal	448	448	1984
Laramie River Generating Station Unit 1	Wyoming	28.5	Coal	560	—	1980
Laramie River Generating Station Unit 2	Wyoming	28.5	Coal	570	241	1981
Laramie River Generating Station Unit 3	Wyoming	28.5	Coal	570	241	1982
Springerville Generating Station Unit 3	Arizona	100.0	Coal	418	418	2006
Gas/Oil						
Burlington Generating Station	Colorado	100.0	Oil	110	110	1977
J.M. Shafer Generating Station	Colorado	100.0	Gas	272	272	1994
Knutson Generating Station	Colorado	100.0	Gas/Oil	140	140	2002
Limon Generating Station	Colorado	100.0	Gas/Oil	140	140	2002
Pyramid Generating Station	New Mexico	100.0	Gas/Oil	160	160	2003

* The Unit Ratings and our share for each generating facility are subject to fluctuations to account for various operating conditions and environmental mitigation equipment requirements.

Craig Generating Station. Craig Station is a three-unit, 1,285 MW coal-fired electric generating facility located near Craig, Colorado. Craig Station Units 1 and 2 and related common facilities are known as the Yampa Project and jointly owned as tenants in common by us and four other regional utilities pursuant to a participation agreement. We own a 24 percent interest in Craig Station Units 1 and 2, which each have a capacity of 427 MWs and 410 MWs, respectively, and a 100 percent interest in Craig Station Unit 3, which has a capacity of 448 MWs. We are the operating agent for all three units and are responsible for the daily management, administration and maintenance of the facility. The costs associated with operating Craig Station Units 1 and 2 are divided on a pro-rata basis among all the participants. Our total share of Craig Station's capacity is 648 MWs. On September 1, 2016, we announced that the owners of Craig Station Unit 1 reached an agreement whereby Unit 1 is intended to be retired by December 31, 2025. We and the other joint owners of Craig Station Unit 2 intend to retire Craig Station Unit 2 by September 30, 2028. We intended to retire Craig Station Unit 3 by January 1, 2028 as part of Phase I of our approved 2023 ERP.

Laramie River Generating Station. Laramie River Generating Station is a three-unit, 1,700 MW coal-fired electric generating facility located near Wheatland, Wyoming and operated by Basin. Laramie River Generating Station and related transmission lines are known as the MBPP and are jointly owned as tenants in common by us and three other regional utilities pursuant to a participation agreement. We own a 28.5 percent interest in the total capacity of the facility. Certain costs associated with operating the facility are divided on a pro-rata basis among the participants, while other costs are shared in proportion to the generation scheduled and energy produced for each participant. Laramie River Generating Station Unit 1 is connected to the Eastern Interconnection, while Units 2 and 3 are connected to the Western Interconnection. Our share of Laramie River Generating Station's total capacity is 482 MWs, which we receive out of Units 2 and 3.

Springerville Generating Station Unit 3. Springerville Unit 3, located in east-central Arizona, is a 418 MW unit that is part of a four-unit, 1,578 MW coal-fired electric generating facility operated by TEP. Under contractual agreements, we, as the lessee of Springerville Unit 3, are taking 418 MWs of capacity from the unit and selling 100 MWs of such capacity to Salt River Project. We own a 51 percent equity interest (including the 1 percent general partner equity interest) in Springerville Partnership, which owns Springerville Unit 3. Our leasehold interest, as the lessee of Springerville Unit 3, is subject to the lien of our Master Indenture, but Springerville Unit 3 is not subject to the lien of our Master Indenture. Springerville Unit 3 is subject to a mortgage and lien to secure the Springerville certificates. As part of Phase I of our approved 2023 ERP and subject to receipt of New ERA Program funding related to Springerville Unit 3 and reaching agreements with the applicable parties, we intended to retire Springerville Unit 3 by March 1, 2031.

Burlington Generating Station. Burlington Generating Station consists of two 55 MW simple-cycle combustion turbines that operate on fuel oil and is located in Burlington, Colorado. The units are primarily operated during periods of peak demand. Burlington Generating Station is wholly owned and operated by us.

J.M. Shafer Generating Station. J.M. Shafer Generating Station is a 272 MW, natural gas-fired, combined-cycle generating facility located near Fort Lupton, Colorado, which is primarily operated to provide intermediate load generating capacity. J.M. Shafer Generating Station is wholly owned and operated by us.

Knutson Generating Station. Knutson Generating Station consists of two 70 MW simple-cycle combustion turbines that can operate on either natural gas or fuel oil and is located near Brighton, Colorado. The units are primarily operated during periods of peak demand. Knutson Generating Station is wholly owned and operated by us. Both units are under contract with a third party under a tolling arrangement through December 2027, which is an arrangement whereby the purchaser provides its own natural gas for generation of electricity.

Limon Generating Station. Limon Generating Station consists of two 70 MW simple-cycle combustion turbines that can operate on either natural gas or fuel oil and is located near Limon, Colorado. The units are primarily operated during periods of peak demand. Limon Generating Station is wholly owned and operated by us. One unit is under contract with a third party under a tolling arrangement starting January 2026 through September 2027.

Pyramid Generating Station. Pyramid Generating Station consists of four 40 MW simple-cycle combustion turbines that can operate on either natural gas or fuel oil and is located near Lordsburg, New Mexico. The units are primarily operated during periods of peak demand. Pyramid Generating Station is wholly owned and operated by us. One unit is under contract with a third party under a tolling arrangement that started January 2025 through December 2027.

Transmission

As of December 31, 2024, we own, lease, or have undivided percentage interest in transmission lines as described in the following table (estimated miles based on Geographic Information System):

Voltage (kV)	Miles
69	56
115	3,280
138	185
230	1,198
345	1,100
Total	5,819

We are an ownership participant in the MBPP (Laramie River Generating Station) and Yampa Project (Craig Station Units 1 and 2) transmission systems and have ownership interests or capacity rights in several other transmission line participation projects. As of December 31, 2024, transmission investment also includes ownership or major equipment ownership in 407 substations and switchyards. All our interests in these facilities or agreements, as applicable, are subject to the lien of our Master Indenture.

Coal Mines

We, through our wholly owned subsidiary Colowyo Coal, own the Colowyo Mine, which is a surface mine located near Craig, Colorado. The Colowyo Mine is our only mine that we own that has active mining operations. In September 2024, our Board decided to transition from mining to full reclamation at the Colowyo Mine by the end of 2025.

We, through our wholly owned subsidiary Elk Ridge, also own the New Horizon Mine, which is located near Nucla, Colorado. The New Horizon Mine is in post-reclamation monitoring and no longer produces coal.

ITEM 3. LEGAL PROCEEDINGS

Information required by this Item is contained in "Note 14—Commitments and Contingencies—Legal" to the Consolidated Financial Statements in Item 8.

ITEM 4. MINE SAFETY DISCLOSURES

Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95 to this annual report on Form 10-K.

PART II

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

Not Applicable.

ITEM 6. [RESERVED]

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

Overview

We are a taxable wholesale electric power generation and transmission cooperative operating on a not-for-profit basis. We were formed by our Utility Members for the purpose of providing wholesale power and transmission services to our Utility Members (which are distribution electric cooperatives and public power districts) for their resale of the power to their retail consumers. Our Utility Members serve large portions of Colorado, Nebraska, New Mexico and Wyoming. We also sell a portion of our generated electric power to other utilities in our regions pursuant to long-term contracts and short-term sale arrangements. Our Utility Members provide retail electric service to suburban and rural residences, farms and ranches, cities, towns and communities, as well as large and small businesses and industries.

We are owned entirely by our forty-three Members of which forty are Utility Members. Thirty-six of our Utility Members are not-for-profit, electric distribution cooperative associations. Four Utility Members are public power districts, which are political subdivisions of the State of Nebraska. We also have three Non-Utility Members. We are regulated as a public utility under Part II of the FPA.

We supply and transmit our Utility Members' electric power requirements through a portfolio of resources, including generation and transmission facilities, long-term purchase contracts and short-term energy purchases. We own, lease, have undivided percentage interests in, or long-term purchase contracts with respect to various generating facilities. Our diverse generation portfolio provides us with maximum available power of 4,661 MWs, of which approximately 1,698 MWs comes from renewables.

In 2024, we sold 17.8 million MWhs, of which 84.1 percent was to Utility Members. Total revenue from electric sales was $1.3 billion for the year ended December 31, 2024, of which 84.9 percent was from Utility Member sales. Our results for the year ended December 31, 2024 were primarily impacted by the withdrawal of United Power as a Utility Member, lower natural gas prices, as well as increased renewable generation throughout the Western region, which resulted in lower electric market prices. Therefore, our market-based purchases were higher during 2024, which resulted in lower generation from our coal-fired generating facilities. Additionally our results during 2024 were impacted by higher rate stabilization measures.

- Utility Member electric sales decreased $102.7 million, or 8.5 percent, primarily due to a decrease of 1,571,226 MWhs sold, or 9.5 percent, during 2024 compared to the same period in 2023. The impact of United Power's withdrawal on May 1, 2024 was offset by increased sales to our remaining Utility Members due to load growth and other factors.
- Non-member electric sales increased $51.3 million primarily due to higher long-term sales (in MWhs) partially offset by lower average prices.
- Rate stabilization represents recognition of income from withdrawal of former Utility Members from membership in us that was previously deferred in accordance with accounting requirements related to regulated operations. We recognized $211.2 million of previously deferred membership withdrawal income during 2024 compared to $47.1 million of previously deferred membership withdrawal income during 2023 as part of our rate stabilization measures.
- Fuel expense decreased $25.5 million, or 9.9 percent, primarily due to lower generation from our coal-fired generating facilities. The lower generation resulted from average market prices being below our generating costs; therefore, more power was purchased in the market.

Wholesale Electric Service Contracts

Our Bylaws require each Utility Member, unless otherwise specified in a written agreement or the terms of the Bylaws, to purchase from us electric power and energy as provided in the Utility Member's contract with us. This contract is the wholesale electric service contract with each Utility Member, which is an all-requirements contract. Each wholesale electric service contract obligates us to sell and deliver to the Utility Member, and obligates the Utility Member to purchase and receive from us, all energy and capacity required for the operation of the Utility Member's system, as modified by two programs (5 percent self-supply and our BYOR Program). Our wholesale electric service contracts with our forty Utility Members extend through 2050. Each Utility Member may elect to provide up to 5 percent of its electric power requirements from distributed or renewable generation owned or controlled by the Utility Member. As of December 31, 2024, 21 Utility Members have enrolled in this 5 percent self-supply provision with capacity totaling approximately 94 MWs of which 89 MWs are in operation. See "BUSINESS – MEMBERS" for a description of our wholesale electric service contract.

During 2024, we developed our BYOR Program, which is designed to provide our Utility Members with the flexibility to build, own or contract for power supply projects while avoiding cost shifts amongst our Utility Members. Under the BYOR Program, Utility Members interested in participating in the BYOR Program will propose projects that they will own or control and that do not exceed 40 percent of their 2022 peak load during our peak period and which projects will not have an adverse impact on our reliability, overall system costs or compliance with environmental objectives. If a Utility Member-proposed resource is accepted following the program evaluation process, a Utility Member will enter into an agreement enabling us to purchase the output of the BYOR project and that output will be deemed to serve the Utility Member's load.

In August 2024, FERC accepted our tariff describing the parameters of the BYOR Program and the inaugural BYOR Program cycle was initiated in the third quarter of 2024. Collectively, 11 Utility Members brought four projects totaling 330 MWs in the inaugural BYOR Program cycle, with execution of agreements with us and the participating Utility Members expected in 2025. See "BUSINESS – MEMBERS" for more specifics on our BYOR Program.

Our wholesale electric service contracts with our Utility Members also provide for us to establish a committee every 5 years to review the wholesale electric service contracts for the purposes of making recommendations to our Board concerning any suggested modifications. The current contract committee is currently discussing various contract provisions, including extending the term of the wholesale electric service contract beyond 2050. See "BUSINESS – MEMBERS" for more specifics on our contract committee.

Member Withdrawals and Relationship with Members

Pursuant to our Bylaws, a Member may only withdraw from membership in us upon compliance with such equitable terms and conditions as our Board may prescribe provided, however, that no Member shall be permitted to withdraw until it has met all its contractual obligations to us. In September 2021, we filed with FERC a modified contract termination payment methodology tariff as Rate Schedule 281 that provides a process should a Utility Member elect to withdraw from membership in us and terminate its wholesale electric service contract with us. The tariff process includes requirements for a two-year notice and the payment to us of a contract termination payment. In October 2021, FERC accepted our modified contract termination payment methodology, effective November 1, 2021, subject to refund. FERC set the matter for hearing and instituted a concurrent FPA section 206 proceeding to determine the justness and reasonableness of our modified methodology.

In December 2023, FERC issued an order adopting a modified balance sheet approach for the contract termination payment methodology. We have filed multiple revised Rate Schedule 281 with FERC as directed by FERC's compliance filing orders, including our latest revised Rate Schedule 281 that we filed in February 2025. For further information see "BUSINESS – MEMBERS - Contract Termination Payment and Relationship with Members and "Note 14—Commitments and Contingencies—Legal" to the Consolidated Financial Statements in Item 8 for further information.

In April 2022, both United Power and NRPPD provided us non-conditional notices to withdraw from membership in us, with a May 1, 2024, withdrawal effective date. In January 2023, MPEI provided us a non-conditional notice to withdraw from membership in us, with a February 1, 2025, withdrawal effective date. In March 2024, LPEA provided us a non-conditional notice to withdraw from membership in us, with an April 1, 2026, withdrawal effective date.

On May 1, 2024, United Power withdrew its membership in us and pursuant to Rate Schedule 281 and a Membership Withdrawal Agreement terminated its wholesale electric service contract with us. United Power's contract termination payment amount was $709.4 million. United Power paid us an exit fee in cash of $627.2 million, after a regulatory liabilities credit and relinquishing its right to any patronage capital in us resulting in a discounted patronage capital credit of $82.2 million. Such amounts remain subject to true up in accordance with Rate Schedule 281 and United Power's Membership Withdrawal Agreement. Our Board deferred as a regulatory liability $530.1 million of United Power's $709.4 million contract termination payment amount. The remaining $179.3 million was related to a transmission credit based upon the Rate Schedule 281 in effect at that time for the portion of transmission debt allocated to United Power and required to be deferred pursuant to FERC's December 2023 order and Rate Schedule 281. The amount of transmission credit is subject to increase based upon FERC's latest compliance filing order and FERC's acceptance of our February 2025 revised Rate Schedule 281.

NRPPD did not comply with the rate schedule arising out of its April 2022 notice of intent to withdraw and made no contract termination payment to us and thus remains a Utility Member of us. NRPPD provided us a second non-conditional notice of intent to withdraw in December 2024, with a January 1, 2027, withdrawal effective date. We cannot predict if NRPPD will withdraw from us and terminate its wholesale electric service contract early.

On February 1, 2025, MPEI withdrew its membership in us and pursuant to Rate Schedule 281 and a Membership Withdrawal Agreement terminated its wholesale electric service contract with us. MPEI's contract termination payment amount was $86 million, including MPEI's pro rata share of our power purchase obligations in the Western Interconnection. MPEI paid us an exit fee in cash of $71.6 million and relinquished its right to any patronage capital in us resulting in a discounted patronage capital credit of $14.5 million. Such amounts remain subject to true up in accordance with Rate Schedule 281 and MPEI's Membership Withdrawal Agreement. Our Board is expected to defer as a regulatory liability $66.3 million of MPEI's $86 million contract termination payment amount. The remaining $19.7 million was related to a transmission credit based upon the Rate Schedule 281 in effect at that time for the portion of transmission debt allocated to MPEI and required to be deferred pursuant to FERC's December 2023 order and Rate Schedule 281. The portion of the contract termination payment allocated to the transmission credit is subject to increase based upon FERC's latest compliance filing order and FERC's acceptance of our February 2025 revised Rate Schedule 281.

LPEA's estimated contract termination payments based upon the February 2025 version of Rate Schedule 281 is $209.7 million prior to any adjustment related to the discounted patronage capital. The estimated contract termination payment for LPEA does not include its pro rata share of our power purchase obligations in the Western Interconnection. MPEI, LPEA, and NRPPD comprised 8.7 percent of our Utility Member revenue and 5.0 percent of our operating revenue for 2024.

Consistent with prior withdrawals of Utility Members, we anticipate that some or all of MPEI's and LPEA's contract termination payments received may be deferred as regulatory liabilities, subject to our Board's discretion, and the contract termination payments from United Power, MPEI, and La Plata may be recognized as revenue in future periods to offset the revenue otherwise recoverable from Utility Members. We expect our non-member electric sales revenue and the amount of energy sold to non-members to increase significantly in the future. In anticipation of excess capacity resulting from Utility Member withdrawals, we have entered into multiple power sales contracts with third parties for up to 515 MWs and multiple tolling agreements for 250 MWs in total from units at our simple-cycle combustion turbines, with 265 MWs of the power sales contracts and 180 MWs of the tolling agreements currently in effect. A tolling agreement is an arrangement whereby the purchaser provides its own natural gas for generation of electricity. See also "BUSINESS – MEMBERS - Contract Termination Payment and Relationship with Members" and "RISK FACTORS - Members and Regulatory Risks."

In November 2023, LPEA filed a complaint for declaratory judgement and damages against us alleging, among other things, that we have breached our Bylaws and our wholesale electric service contract with LPEA. Such litigation was dismissed in January 2025. See "Note 14—Commitments and Contingencies—Legal" to the Consolidated Financial Statements in Item 8 for further information.

Colorado Electric Resource Plan and New ERA Program

Colorado Electric Resource Plan

In December 2023, we filed our Phase I of our 2023 ERP with the COPUC, which contained our preferred plan. Our preferred plan is the IRA scenario that forecasted the need for approximately 1,500 MWs of new resources during the resource acquisition period of 2026-2031. Our preferred plan retires Craig Station Unit 3 by January 1, 2028 and, if we receive New ERA Program funding and reach agreements with the applicable parties, our preferred plan retires Springerville Unit 3 by March 1, 2031.

In June 2024, we executed a comprehensive settlement agreement for Phase I of our 2023 ERP supporting its approval by the COPUC subject to the terms of the settlement, including the above referenced retirements of our generating facilities. The settlement agreement further provides for us to provide community assistance for northwest Colorado. For Phase II of our 2023 ERP, we issued three requests for proposals in September 2024. We received 145 bids related to 128 projects for over 21,000 MWs from these projects. See "BUSINESS – POWER SUPPLY RESOURCES – Resource Planning."

New ERA Program

In September 2023, we submitted a Letter of Interest to apply for a funding award of low-cost loans and grants through the New ERA Program, a $9.7 billion USDA program that is funded by the IRA. Our portfolio proposed in our Letter of Interest was the result of resource and financial modeling performed in connection with our preferred IRA scenario as part of Phase I of our 2023 ERP. In March 2024, we received an Invitation to Proceed from the USDA to complete the New ERA Program Application, and in June 2024, we submitted our Application. We have signed award commitment letters from USDA. See "BUSINESS – OVERVIEW."

Solar Projects Construction

In April 2024, we closed on the acquisition of the 145 MW Axial Basin Solar project being developed in northwestern Colorado located near the Colowyo Mine and issued a notice to an engineering, procurement and construction contractor to proceed with construction. Construction at Axial Basin continues to progress with cable trenching and plowing complete, racking in progress, module installation in progress and all power stations set. All the Axial Basin solar modules have been received on site.

In May 2024, we closed on the acquisition of the 110 MW Dolores Canyon Solar project being developed in southwestern Colorado and issued a notice to an engineering, procurement and construction contractor to proceed with construction. Construction at Dolores Canyon continues to progress with the access roads and directional bores complete, cable trenching and plowing in progress, as well as racking and module installation in progress. All the Dolores Canyon solar modules have been received on site or placed in storage.

Both projects are expected to achieve commercial operation in the second half of 2025. We also expect to utilize direct pay of federal tax benefits as provided in the IRA for both projects.

Colowyo Mine Transition

In September 2024, our Board approved a 2025 budget reflecting a decision to transition from mining to full reclamation at Colowyo Coal's Colowyo Mine by the end of 2025. During the third quarter of 2024, we expensed $33.2 million in write-offs of acquisition costs/goodwill and pre-paid royalties related to the Colowyo Mine, and we accelerated approximately $7.4 million in depreciation and amortization related to asset retirement obligations, development costs and depletion of coal reserves. In addition, we recorded $5.3 million of obsolete inventory in the fourth quarter of 2024. Accelerated depreciation and amortization will continue from the third quarter of 2024 through the latter part of 2025 in the approximate amounts of $22.2 million and $72.6 million, respectively. We recognized deferred membership withdrawal income in an amount equal to such expenses resulting in no impact to our Utility Member's wholesale rate for 2024.

Changing Environmental Regulations

We are subject to extensive federal, state and local environmental requirements. Generally, existing environmental regulations are becoming increasingly stringent, including those related to greenhouse gas emissions or renewable or clean energy standards. The current federal administration is expected to bring a change in direction for environmental regulations. At this time, it is impossible to predict what changes in current regulations or new regulations or legislation may occur under the current federal administration.

In Colorado, the AQCC is required to develop rules to reduce statewide greenhouse gas emissions 26 percent by 2025, 50 percent by 2030, and 90 percent by 2050, relative to 2005 emissions. In New Mexico, the RPS requires our New Mexico Utility Members to obtain 40 percent renewable energy by 2025 and 50 percent renewable energy by 2030 and adds a target of achieving a zero carbon resource standard by 2050, with at least 80 percent renewable energy. See "BUSINESS – ENVIRONMENTAL REGULATION" and "RISK FACTORS - Environmental Risks."

Critical Accounting Policies

The preparation of our financial statements in conformity with GAAP requires that our management make estimates and assumptions that affect the amounts reported in our consolidated financial statements. We base these estimates and assumptions on information available as of the date of the financial statements and they are not necessarily indicative of the results to be expected for the year. We consider the following accounting policies to be critical accounting policies due to the estimation involved or due to the particular significance they have on our consolidated financial statements.

Accounting for Rate Regulation. We are a rate-regulated entity and, as a result, are subject to the accounting requirements of Accounting for Regulated Operations. In accordance with these accounting requirements, some revenues and expenses have been deferred at the discretion of our Board, subject to FERC approval, if it is probable that these amounts will be refunded or recovered through future rates. Regulatory assets are costs we expect to recover from Utility Members based on rates approved by the applicable authority. Regulatory liabilities represent probable future reductions in rates associated with amounts that are expected to be refunded to Utility Members based on rates approved by the applicable authority. Amounts that are no longer expected to be refunded to our Utility Members are recognized in margins. Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions by FERC or precedent for each item. We recognize regulatory assets as expenses and regulatory liabilities as operating revenue, other income, or a reduction in expenses concurrent with their recovery in rates.

Asset Retirement and Environmental Remediation Obligations. We account for current obligations associated with the future retirement of tangible long-lived assets and environmental remediation in accordance with the accounting guidance relating to asset retirement and environmental obligations. This guidance requires that legal obligations associated with the retirement of long-lived assets be recognized at fair value at the time the liability is incurred and capitalized as part of the related long-lived asset. Over time, the liability is adjusted to its present value by recognizing accretion expense, and the capitalized cost of the long-lived asset is depreciated in a manner consistent with the depreciation of the underlying physical asset. In the absence of quoted market prices, we determine fair value by using present value techniques in which estimates of future cash flows associated with retirement activities are discounted using a credit adjusted risk-free rate and market risk premium. Upon settlement of an asset retirement obligation, we will apply payment against the estimated liability and incur a gain or loss if the actual retirement costs differ from the estimated recorded liability.

Environmental remediation costs are accrued based on management's best estimate at the end of each period of the costs expected to be incurred. Such cost estimates may include ongoing care, maintenance and monitoring costs. Changes in remediation estimates are reflected in earnings in the period an estimate is revised. Estimates of future expenditures for environmental remediation obligations are not discounted.

Factors Affecting Results

Master Indenture

Our Master Indenture requires us to establish, subject to any necessary regulatory approvals, rates annually that are reasonably expected to achieve a DSR of at least 1.10 on an annual basis and permits us to incur additional secured obligations as long as, after giving effect to the additional secured obligation, we will continue to meet the DSR requirement on both a historic and pro forma basis. Our DSR is calculated by dividing (x) our Net Margins Available for Debt Service (as defined in our Master Indenture), which is equal to our net margins for a period plus amounts deducted for the period to pay or make provision for interest on debt (including capitalized interest other than Allowance for Funds Used During Construction), lease expense, income tax expense, amortization of debt discount or premium, and depreciation and certain other non-cash items by (y) our Annual Debt Service Requirement (as defined in our Master Indenture), which is generally equal to the principal of, premium, if any, and interest (whether capitalized or expensed) on all of our debt and lease payments that become due in the applicable fiscal year or 12-month period at maturity or stated maturity, subject to special calculation rules applicable to specific types of debt (such as balloon debt). For purposes of the DSR calculation, we are permitted to exclude from the Annual Debt Service Requirement principal and interest on debt if the debt is paid or to be paid from defeasance obligations which have been irrevocably deposited or set aside in trust for payment of such debt. Our failure to achieve the required DSR is not a default under our Master Indenture as long as a plan is timely adopted and being implemented and no payment default has occurred. However, subject to certain limited exceptions, we cannot issue additional secured obligations under our Master Indenture unless the DSR for the prior fiscal year (or period of prior 12 consecutive months) is at least 1.10 and the estimated DSR for the current and next two years (or, if applicable, two years following the anticipated commercial operation date of the assets being financed) is at least 1.10. A DSR below 1.025 under our Master Indenture would require us to transfer all cash to a special fund managed by the trustee of our Master Indenture until our DSR is at least 1.025. We estimate that our DSR for the twelve months ended December 31, 2024 was 1.36.

Our Master Indenture also requires us to maintain an ECR at the end of each fiscal year of at least 18 percent. Our ECR equals our equity divided by the sum of our debt plus equity. Equity primarily consists of our aggregate net margins that we have not distributed in cash to our Members. Debt includes our indebtedness for borrowed money and capitalized leases but excludes indebtedness for which defeasance obligations (i.e., non-callable obligations of the U.S.) have been irrevocably deposited in trust. Our failure to maintain the ECR at the end of any given fiscal year would result in an event of default under our Master Indenture and restrict our ability to issue additional secured obligations under our Master Indenture. We estimate that as of December 31, 2024, our ECR was 24.7 percent.

As of December 31, 2024, we had approximately $2.8 billion of secured indebtedness outstanding under our Master Indenture. Substantially all of our tangible assets and certain of our intangible assets are pledged as collateral under our Master Indenture. Pursuant to our Master Indenture, the DSR and ECR are calculated based on unconsolidated Tri-State financials and calculated in accordance with the system of accounts proscribed by FERC, not GAAP. The DSR and ECR calculated in accordance with FERC's system of accounts are not finalized and are subject to final adjustment.

Margins and Patronage Capital

We operate on a cooperative basis and, accordingly, seek only to generate revenues sufficient to recover our cost of service and to generate margins sufficient to meet certain financial requirements and to establish reasonable reserves. Revenues in excess of current period costs in any year are designated as net margins in our consolidated statements of operations. Net margins are treated as advances of capital by our Members and are allocated to our Utility Members on the basis of revenue from electricity purchases from us and to our Non-Utility Members as provided in their respective membership agreement.

Our Board Policy for Financial Goals and Capital Credits, approved and subject to change or waiver by our Board, sets guidelines to achieve margins and retain patronage capital sufficient to maintain a sound financial position and to allow for the orderly retirement of capital credits allocated to our Members. On a periodic basis, our Board will determine whether to retire any patronage capital, and in what amounts, to our Members. As of December 31, 2024, we have retired in aggregate approximately $615.8 million of patronage capital to our Utility Members.

Our Board Policy for Financial Goals and Capital Credits includes three financial ratio goals for which we will set rates based upon an annual budget and true-up from the actual results of the previous fiscal year. The three financial goals are: (i) a minimum DSR of at least 1.15, (ii) a minimum ECR of at least 20 percent, and (iii) a minimum net margin attributable to us in each fiscal year of at least $20 million. Our Board Policy also provides that any extraordinary funds, such as contract termination payments, received by us will be used to offset future costs to our Utility Members. Extraordinary revenue will be recorded (a) in the year received to increase net margins, subject to loan agreement restrictions, (b) in the year received with the same amount of regulatory assets written off in the same fiscal year, resulting in no net change in net margins, or (c) deferred as a regulatory liability in the year received and recognized as revenue in future period or periods, with the oldest vintage year used first. We recognized $211.2 million of previously deferred membership withdrawal income during 2024.

Rates and Regulation

On September 3, 2019, we became FERC jurisdictional for our Utility Member rates, transmission service, and our market-based rates. In March 2020, FERC issued orders generally accepting our December 2019 tariff filings, including our stated rate (A-40) to our Class A members, market-based rate authorization, and transmission OATT. On August 2, 2021, FERC approved our settlement agreement related to our Utility Members' stated rate (A-40) that provides for us to implement a two-stage, graduated reduction in the charges making up our A-40 rate of 2 percent starting from March 1, 2021 until the first anniversary and 4 percent reduction (additional 2 percent reduction) on March 1, 2022 through July 31, 2024.

In May 2024, we filed with FERC a request to adopt a new Class A wholesale rate schedule (A-41) for electric power sales to our Utility Members. The filing included a 6.4 percent increase in our average wholesale rate. The wholesale rate maintains our postage stamp rate, with the same rate components for all our Utility Members, and incorporates a new formulary rate, which can be adjusted annually based on the budgets approved by our Board, including an annual true-up mechanism. In July 2024, FERC issued an order accepting our A-41 wholesale rate schedule, effective August 1, 2024, subject to refund. FERC further set our rate filing for settlement and hearing procedures. See "BUSINESS – RATE REGULATION."

Our electric sales revenues are derived from wholesale electric service sales to our Utility Members and non-member purchasers. Revenues from wholesale electric power sales to our non-member purchasers is primarily pursuant to our market-based rate authority.

Our Class A rate schedule (A-40) for electric power sales to our Utility Members that was in effect through July 2024 consisted of three billing components: an energy rate and two demand rates. Our new Class A formula rate schedule (A-41) for electric power sales to our Utility Members consists of eleven rate components, with three energy-based and eight demand-based and became effective in August 2024. For our A-41 rate schedule, our budget used to set our Utility Member formula rate is set by our Board, consistent with the provision of reliable cost-based supply of electricity over the long term to our Utility Members. Energy is the physical electricity delivered to our Utility Members. The energy-based rates are billed based upon a price per kWh of physical energy delivered and the demand-based rates are billed based on the Utility Member's highest thirty-minute integrated total demand measured in each monthly billing period during our peak period, Monday through Saturday, with the exception of six holidays. For further information on our formula rate see "BUSINESS – RATE REGULATION."

In September 2024, our Board approved our 2025 budget with the wholesale rate to our Utility Members unchanged through 2025.

Our Board may from time to time, subject to FERC approval, create new regulatory assets or liabilities or modify the expected recovery period through rates of existing regulatory assets or liabilities. The amounts involved may be material.

Tax Status

We are a taxable cooperative subject to federal and state taxation. As a taxable electric cooperative, we are allowed a tax exclusion for margins allocated as patronage capital. We utilize the liability method of accounting for income taxes which requires that deferred tax assets and liabilities be determined based on the expected future income tax consequences of events that have been recognized in the consolidated financial statements. We and our subsidiaries use the flow-through method for recognizing deferred income taxes whereby changes in deferred tax assets or liabilities result in the establishment of a regulatory asset or liability, as approved by our Board. A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be settled or received through future rate revenues.

Results of Operations

General

Our electric sales revenues are derived from wholesale electric service sales to our Utility Members and non-member purchasers. See "—Factors Affecting Results – Rates and Regulation" for a description of our energy and demand rates to our Utility Members. Long-term contract sales to non-members generally include energy and demand components. Short-term sales to non-members are generally sold at market prices after consideration of incremental production costs. Demand billing to non-members are typically billed per kilowatt of capacity reserved or committed to that customer.

Weather has a significant effect on the usage of electricity by impacting both the electricity used per hour and the total peak demand for electricity. Consequently, weather has a significant impact on revenues. Relatively higher summer or lower winter temperatures tend to increase the usage of electricity for heating, air conditioning and irrigation. Mild weather generally reduces the usage of electricity because heating, air conditioning and irrigation systems are operated less frequently. The amount of precipitation during the growing season (generally May through September) also impacts irrigation use. Other factors affecting our Utility Members' usage of electricity include:

- the amount, size and usage of machinery and electronic equipment;
- the expansion or contraction of operations among our Utility Members' commercial and industrial customers;
- the general growth in population; and
- economic conditions.

Supply Chain Impacts

Our ability to meet our Utility Members' electric power requirements and complete our capital projects are dependent on maintaining an efficient supply chain. The procurement and delivery of materials and equipment have been impacted by the current domestic and global supply chain disruptions. We are experiencing shortages of critical items and longer lead-times on the procurement of certain materials and equipment, along with interruptions in production and shipping. Supply chain disruptions and inflation have contributed to higher prices for materials and equipment. We continue to monitor potential impacts to our operations and estimated capital expenditures and timing of projects related to inflationary pressures, tariffs, and supply chain disruptions.

Year ended December 31, 2024 compared to year ended December 31, 2023

Operating Revenues

Our operating revenues are primarily derived from electric power sales to our Utility Members and non-member purchasers. Other operating revenue consists primarily of wheeling, transmission, coal sales, and lease revenue. Other operating revenue also includes revenue we receive from certain of our Non-Utility Members. The following is a comparison of our operating revenues and energy sales in MWhs by type of purchaser for 2024 and 2023 (dollars in thousands):

	Year Ended December 31,		Period-to-Period Change	
	2024	2023	Amount	Percent
Operating revenues				
Utility Member electric sales	$ 1,105,701	$ 1,208,352	$ (102,651)	(8.5)%
Non-member electric sales	196,561	145,228	51,333	35.3 %
Rate stabilization	211,232	47,127	164,105	348.2 %
Provision for rate refunds	(6,556)	94	(6,650)	(7,074.5)%
Other	105,452	66,615	38,837	58.3 %
Total operating revenues	$ 1,612,390	$ 1,467,416	$ 144,974	9.9 %
Energy sales (in MWh):				
Utility Member electric sales	14,959,159	16,530,385	(1,571,226)	(9.5)%
Non-member electric sales	2,838,291	1,694,116	1,144,175	67.5 %
	17,797,450	18,224,501	(427,051)	(2.3)%

- Excluding United Power, Utility Member load growth increased 571,363 MWh, or 4.3 percent, during 2024 compared to the same period in 2023. The United Power membership withdrawal on May 1, 2024 resulted in a decrease of 2,143,108 MWh sold to United Power during 2024 compared to the same period in 2023. The impact of the United Power membership withdrawal to total Utility Member electric sales (in dollars and MWhs) was lower than anticipated due to the load growth from our remaining Utility Members, and an increase in non-member electric sales.
- Non-member electric sales revenue increased primarily due to higher long-term sales partially offset by lower market prices. Long-term sales increased 1,164,181 MWhs to 1,441,804 MWhs in 2024 compared to 277,623 MWhs for the same period in 2023. The ability to sell excess power to non-members after United Power's membership withdrawal contributed significantly to the increase in non-member electric sales.
- We recognized $211.2 million of deferred membership withdrawal income during 2024 compared to $47.1 million of deferred membership withdrawal income during the same period in 2023 as part of our rate stabilization measures. The 2024 deferred membership withdrawal income includes recognition of $68.2 million of deferred membership withdrawal income in September 2024 to offset the expense recognition related to the write off of the J.M. Shafer Generating Station and Colowyo Coal acquisition costs/goodwill. Additionally, we recognized $32.8 million of deferred membership withdrawal income from September 2024 to December 2024 to offset the expense recognition for accelerated expenses related to the transition from mining to full reclamation at the Colowyo Mine in 2025, $39.1 million of deferred membership withdrawal income in December 2024 to offset the expense recognition related to the recording of environmental remediation obligations at New Horizon Mine and Colowyo Mine and $71.1 million of deferred membership withdrawal income during 2024 related to rate stabilization measures in order to meet our financial ratios and goals.
- Other operating revenue increased primarily due to the sale of intangible assets and an increase in lease revenue related to a tolling agreement for our two 70 MW units at the Knutson Generating Station for all capacity and energy through the operation of both units that started on May 1, 2024.

Operating Expenses

Our operating expenses are primarily comprised of the costs that we incur to supply and transmit our Utility Members' electric power requirements through a portfolio of resources, including generation and transmission facilities, long-term purchase contracts and short-term energy purchases and the costs associated with any sales of power to non-members.

The following is a summary of the components of our operating expenses for 2024 and 2023 (dollars in thousands):

	Year Ended December 31,		Period-to-Period Change	
	2024	2023	Amount	Percent
Operating expenses				
Purchased power	$ 408,796	$ 404,876	$ 3,920	1.0 %
Fuel	233,347	258,894	(25,547)	(9.9)%
Production	171,879	191,095	(19,216)	(10.1)%
Transmission	180,616	187,874	(7,258)	(3.9)%
General and administrative	115,739	88,621	27,118	30.6 %
Depreciation, amortization and depletion	219,144	171,460	47,684	27.8 %
Coal mining	41,525	44,548	(3,023)	(6.8)%
Goodwill impairment	68,223	—	68,223	100.0 %
Other	10,420	(31,341)	41,761	(133.2)%
Total operating expenses	$ 1,449,689	$ 1,316,027	$ 133,662	10.2 %

- Fuel expense decreased primarily due to 1,659,061 MWh, or 22.6 percent, lower generation from our coal-fired generating facilities and a lower average rate for natural gas.
- General and administrative expense increased primarily due to lower recoveries of general and administrative costs from joint project activities and an overall increase in expenses related to general and administrative labor and benefits.
- Depreciation, amortization and depletion expense increased primarily due to accelerated depreciation and amortization from the transition from mining to reclamation at Colowyo Mine later in 2025.
- Goodwill impairment is due to the expense recognition related to the write-off of the J.M. Shafer Generating Station and Colowyo Coal acquisition costs/goodwill.
- Other operating expenses was impacted during 2023 as a result of a $44.9 million of New Horizon Mine environmental obligation expense that was recorded in 2022 and reversed as a regulatory item in 2023.

Year ended December 31, 2023 compared to year ended December 31, 2022

For discussion of our results of operations comparing the year ended December 31, 2023 to the year ended December 31, 2022, see "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 of our 2023 Annual Report on Form 10-K, filed with the SEC on March 15, 2024.

Financial Condition as of December 31, 2024 compared to December 31, 2023

Assets

Construction work in progress increased $204.5 million, or 124.7 percent, to $368.5 million as of December 31, 2024 compared to $164.0 million as of December 31, 2023. The increase was primarily due to the Axial Basin Solar and the Dolores Canyon Solar facility purchases and construction costs, capital expenditures for various transmission and generation projects and upgrading software systems to hosted solutions.

Investments in other associations increased $5.0 million, or 2.7 percent, to $192.7 million as of December 31, 2024 compared to $187.7 million as of December 31, 2023. The increase was primarily due to a Basin patronage capital allocation of $9.8 million and a CoBank patronage capital allocation of $3.8 million partially offset by patronage capital retirements of $9.7 million (primarily due to a Basin patronage capital retirement of $5.4 million and a CoBank patronage capital retirement of $3.1 million).

Equity and Liabilities

Long-term debt decreased $39.2 million to $2.857 billion as of December 31, 2024 compared to $2.897 billion as of December 31, 2023 and current maturities of long-term debt decreased $134.8 million, or 60.3 percent, to $88.7 million as of December 31, 2024 compared to $223.5 million as of December 31, 2023. The total decrease of $173.9 million was primarily due to paying off the $150 million 2023 multiple advance rate term loan and $128 million bullet maturity for our First Mortgage Bonds, Series 2014E-1. These decreases were partially offset by the draw of a $200 million variable rate December 2024 loan to support the construction costs of the Axial Basin Solar and Dolores Canyon Solar projects.

Member advances decreased $9.2 million, or 64.2 percent, to $5.1 million as of December 31, 2024 compared to $14.3 million as of December 31, 2023. Utility Member advances represents the principal amount of funds received from our Utility Members for prepayment of the Utility Member's monthly power bills and the balance varies depending on how our Utility Members decide how much of their prepayment to apply against their power bills each month and how much they want to roll over to the next month.

Short-term borrowings decreased $184.3 million as of December 31, 2023 to zero as of December 31, 2024. The majority of the decrease was due to paying down debt using some of United Power's contract termination payment and cash proceeds from the $200 million variable rate loan.

Regulatory liabilities increased $494.7 million to $497.0 million as of December 31, 2024 compared to $2.3 million as of December 31, 2023. The increase was primarily due to United Power's $709.4 million contract termination payment amount. Our Board deferred as a regulatory liability $530.1 million of United Power's contract termination payment amount. The remaining $179.3 million was related to a transmission credit and required to be deferred pursuant to FERC's December 2023 order and Rate Schedule 281. Regulatory liabilities was also impacted by the recognition of deferred membership withdrawal income of $211.2 million during 2024 as part of our rate stabilization measures, including $68.2 million related to the write off of the J.M. Shafer Generating Station and Colowyo Coal acquisition costs/goodwill, $32.8 million related to Colowyo Mine's transition to full reclamation in 2025, $39.1 million related to the recording of environmental remediation obligations at New Horizon Mine and Colowyo Mine and $71.1 million in order to meet our financial goals in our Board Policy for Financial Goals and Capital Credits.

Asset retirement obligations increased $47.8 million, or 26.0 percent, to $243.4 million as of December 31, 2024 compared to $195.6 million as of December 31, 2023. The increase was primarily due to the recording of an environmental remediation obligation of $35.8 million at Colowyo Coal's East Taylor pit, the recording of asset retirement obligations of $2.5 million at the Axial Basin and Dolores Canyon solar facilities and accretion of $10.3 million. Additionally, a change in estimate was recorded during 2024 related to the Collom pit asset retirement obligation due to a change in the planned timing of full reclamation to 2025 and an updated cost estimate. These increases were partially offset by asset retirement obligation settlements of $6.6 million.

Liquidity and Capital Resources

We finance our operations, working capital needs and capital expenditures from operating revenues and issuance of short-term and long-term borrowings. As of December 31, 2024, we had $229.4 million in cash and cash equivalents. Our committed credit arrangement as of December 31, 2024 is as follows (dollars in thousands):

	Authorized Amount	Available December 31, 2024
2022 Revolving Credit Agreement	$ 520,000 (1)	$ 517,000 (2)

(1) The amount of this facility that can be used to support commercial paper is limited to $500 million.

(2) The portion of this facility that was unavailable as of December 31, 2024 was $3 million, which was related to an outstanding letter of credit for the benefit of RUS as part of our loan agreement for the Rural Energy Savings Program.

We have a secured 2022 Revolving Credit Agreement with aggregate commitments of $520 million. The 2022 Revolving Credit Agreement includes a swingline sublimit of $125 million, a letter of credit sublimit of $75 million, and a commercial paper back-up sublimit of $500 million, of which $125 million of the swingline sublimit, $72 million of the letter of credit sublimit, and $500 million of the commercial paper back-up sublimit remained available as of December 31, 2024. As of December 31, 2024, we had $517 million of availability under the 2022 Revolving Credit Agreement.

The 2022 Revolving Credit Agreement is secured under our Master Indenture and has a maturity date of April 25, 2027, unless extended as provided therein. Funds advanced under the 2022 Revolving Credit Agreement bear interest either at adjusted Term SOFR rates or alternative base rates, at our option. The adjusted Term SOFR rate is the Term SOFR rate for the term of the advance plus a margin (1.25 percent as of December 31, 2024) based on our credit ratings. Base rate loans bear interest at the alternate base rate plus a margin (0.25 percent as of December 31, 2024) based on our credit ratings. The alternate base rate is the highest of (a) the federal funds rate plus ½ of 1.00 percent, (b) the prime rate, and (c) the adjusted Term SOFR rate plus 1.00 percent and plus a margin (1.25 percent as of December 31, 2024) based on our credit ratings. Due to the letter of credit for the benefit of RUS, we had $3 million used of our availability as of December 31, 2024.

The 2022 Revolving Credit Agreement contains customary representations, warranties, covenants, events of default and acceleration, including financial DSR and ECR requirements in line with the covenants contained in our Master Indenture. A violation of these covenants would result in the inability to borrow under the facility.

Under our commercial paper program, our Board authorized us to issue commercial paper in amounts that do not exceed the commercial paper back-up sublimit under our 2022 Revolving Credit Agreement, which was $500 million as of December 31, 2024, thereby providing 100 percent dedicated support for any commercial paper outstanding. As of December 31, 2024, we had no commercial paper outstanding and $500 million available on the commercial paper back-up sublimit.

On May 8, 2024, we used a portion of the cash from United Power's contract termination payment to pay off the $150 million balance on our 2023 multiple advance rate term loan agreement with CoBank, as administrative agent.

We entered into both a loan agreement and security agreement, dated October 1, 2024, with RUS, a part of the USDA, for a $75 million zero percent interest loan. The loan agreement includes financial DSR requirements in line with the covenants contained in our Master Indenture. This loan was provided by RUS as part of the Rural Energy Savings Program pursuant to the Farm Security and Rural Investment Act of 2002. We can draw up to $50 million of this loan as part of our new Electrify and Save® On-Bill Repayment Program that allows our Utility Members' customers to install energy efficiency measures, at no upfront cost, and repay over time through their monthly utility bill from our Utility Members the costs of the measures and installation, at low interest rates. The remaining $25 million may be used as permitted in our work plan with RUS. Other than a special draw of $3 million that is due at maturity, each draw must be repaid within 10 years. The loan has a final maturity of October 1, 2044 and is not secured under our Master Indenture, but rather secured by certain depository accounts related to the On-Bill Repayment Program and certain rights in our On-Bill Repayment Program. As of December 31, 2024, we had no draws under this loan.

As a requirement of the loan from RUS, we must maintain a letter of credit for the benefit of RUS equal to 50 percent of the amount drawn and outstanding from the loan. We have provided RUS a letter of credit for $3 million issued under our 2022 Revolving Credit Agreement for expected upcoming draws as part of our On-Bill Repayment Program.

Our First Mortgage Bonds, Series 2014E-1 with $128 million outstanding matured on November 1, 2024. The bonds were paid off in full at maturity on November 1, 2024.

On December 12, 2024, we entered into a three-year, $200 million variable interest rate loan with Wells Fargo Bank, National Association. On the date of closing, we drew the full $200 million from the loan. The loan will support the construction costs of the Axial Basin Solar and Dolores Canyon Solar projects.

We have previously purchased our outstanding debt through cash purchases in open market purchases. In the future, we may from time to time purchase additional outstanding debt through cash purchases and/or exchanges for other securities, in open market purchases, privately negotiated transactions or otherwise and may continue to seek to retire or purchase our outstanding debt. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material. We are mindful of our debt and its maturities, and we continually evaluate options to ensure that our balance sheet and capital structure are aligned with our business and the long-term health of our cooperative.

Our material cash requirements include the following contractual and other obligations.

Debt. As of December 31, 2024, we had $3.0 billion in outstanding obligations, including approximately $2.8 billion of debt outstanding under our Master Indenture, with $88.7 million payable in 2025. We have total future interest payments of $1.9 billion, with $146.2 million payable in 2025.

Construction Obligations. As of December 31, 2024, we had $108.0 million in contractual obligations to complete certain construction projects associated with our generating facilities and transmission system, with $57.0 million payable in 2025.

Coal Purchase Obligations. As of December 31, 2024, we had $183.0 million in contractual obligations to purchase coal for our generating facilities under long-term contracts that expire between 2027 and 2041, including $42.9 million payable in 2025. These contracts require us to purchase a minimum quantity of coal at prices that are subject to escalation clauses that reflect cost increases incurred by the suppliers and market conditions. This does not include any coal purchase obligations with our subsidiaries.

We believe we have sufficient liquidity to fund operations and capital financing needs from projected cash on hand, our commercial paper program, the 2022 Revolving Credit Agreement, and expected contract termination payments from withdrawing Utility Members. See "— Member Withdrawals and Relationship with Members."

Cash Flow

Cash is provided by operating activities and issuance of debt. Capital expenditures comprise a significant use of cash.

Year ended December 31, 2024 compared to year ended December 31, 2023

Operating activities. Net cash provided by operating activities was $841.9 million in 2024 compared to $124.4 million in 2023, an increase of $717.5 million. The increase in net cash provided by operating activities was primarily impacted by United Power's contract termination payment of $709.4 million. Additionally, cash provided by operating activities was impacted by the timing of cash collected from Member accounts receivable and payment of trade payables and accrued expenses.

Investing activities. Net cash used in investing activities was $246.0 million in 2024 compared to $175.1 million in 2023, an increase in net cash used in investing activities of $70.9 million. The increase in net cash used in investing activities was impacted by additional investments in utility plant and timing of payments we made to operating agents of jointly owned facilities to fund our share of costs to be incurred under each project. Additionally, we sold to United Power certain assets for $76.7 million during 2024 that were primarily used to serve United Power's load.

Financing activities. Net cash used in financing activities was $472.3 million in 2024 compared to net cash provided by financing activities of $50.0 million in 2023, an increase in net cash used in financing activities of $522.3 million. The increase in net cash used by financing activities was primarily due to using some of United Power's contract termination payment to pay off the 2023 multiple advance rate term loan and also paying down short-term borrowings. Additionally, financing activities was impacted by a patronage capital retirement of $82.2 million resulting from United Power's withdrawal, with the amount of the discounted patronage capital credit applied to United Power's contract termination payment.

Year ended December 31, 2023 compared to year ended December 31, 2022

For discussion of our cash flow comparing 2023 to 2022, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Cash Flow" in Item 7 of our 2023 Annual Report on Form 10-K, filed with the SEC on March 15, 2024.

Capital Expenditures

We forecast our capital expenditures annually as part of our long-term planning. We regularly review these projections to update our calculations to reflect changes in our future plans, facility closures, facility costs, market factors and other items affecting our forecasts. In the years 2025 through 2027, we forecast that we may invest approximately $1.46 billion in new facilities and upgrades to our existing facilities. Our investment forecast for new facilities and upgrades to existing facilities by capital expenditure category is as follows (dollars in thousands):

	2025	2026	2027	Total
Generation	$ 241,978	$ 183,855	$ 408,846	$ 834,679
Transmission	177,811	198,371	136,783	512,965
General Plant	47,476	19,801	47,812	115,089
Total Capital Expenditures	$ 467,265	$ 402,027	$ 593,441	$ 1,462,733

Our actual capital expenditures depend on a variety of factors, including assumptions related to our 2023 ERP, Utility Member load growth, Utility Member withdrawals, BYOR Program, availability of necessary permits, regulatory changes, environmental requirements, inflation, tariffs, construction delays and costs, receipt of New ERA Program funding, and ability to access capital in credit markets. Thus, actual capital expenditures may vary significantly from our projections.

Capital projects include several transmission projects to improve reliability and load-serving capability throughout our Utility Members' service territories.

Rating Triggers

Our current senior secured ratings are “Baa1 (stable outlook)” by Moody’s, “BBB (stable outlook)” by S&P, and “BBB+ (negative outlook)” by Fitch. Our current short-term ratings are “A-2” by S&P and “F1” by Fitch.

Our 2022 Revolving Credit Agreement includes a pricing grid related to the Term SOFR spread, commitment fee and letter of credit fees due under the facility. Certain of our other loan agreements also include a pricing grid related to the Term SOFR spread. A downgrade of our senior secured ratings could result in an increase in each of these pricing components. We do not believe that any such increase would have a material adverse effect on our financial condition or our future results of operations. However, a downgrade of our senior secured ratings could impact the costs associated with incurring additional debt and could make accessing the debt markets on favorable terms more difficult.

We currently have contracts and other obligations that require adequate assurance of performance. These include organized markets contracts, power contracts, natural gas supply contracts and financial risk management contracts. Some of the contracts are directly tied to us maintaining investment grade credit ratings by S&P and Moody’s. We may enter into additional contracts which may contain adequate assurance requirements. If we are required to provide adequate assurances, it may impact our liquidity, and the amount of adequate assurance required will be dependent on our credit ratings.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Fair Value of Debt

The fair values of debt were estimated using discounted cash flow analyses based on our current incremental borrowing rates for similar types of borrowing arrangements. These valuation assumptions utilize observable inputs based on market data obtained from independent sources and are therefore considered Level 2 inputs (quoted prices for similar assets, liabilities (adjusted) and market-corroborated inputs). The carrying amounts and fair values of our debt as of December 31, 2024 and 2023 are as follows:

	December 31, 2024		December 31, 2023	
	Principal Amount	Estimated Fair Value	Principal Amount	Estimated Fair Value
Total long-term debt	$ 2,961,992	$ 2,726,184	$ 3,137,534	$ 2,909,301

Commodity Price Risk

As a wholesale provider of energy to our Utility Members, we could have exposure to the market price of energy to meet our obligations. We engage in various hedging activities for both natural gas and electricity to mitigate our exposure to market price volatility.

We have an established energy risk management program to manage the commodity price risks associated with natural gas, coal, and electric purchases and electric sales and their potential impact on our Utility Member rates. As a result, our primary risk with respect to energy market price fluctuations in the near-term results from any prolonged and unanticipated outages from our various generating facilities.

As of December 31, 2024, after taking into account our tolling arrangements currently in effect, we have available for our use approximately 260 MWs of simple-cycle turbine capacity that is capable of operating on either natural gas or distillate fuel oil. As of December 31, 2024, we also have available for our use approximately 110 MWs of distillate fuel oil-only simple-cycle turbine capacity, and 272 MWs of our natural gas-only combined-cycle capacity, which affords substantial flexibility in meeting our obligations to serve our Utility Members. In 2024, these resources provided approximately 9.0 percent of our energy available for sale. We expect the use of our natural gas-fired generating facilities to increase with the addition of new renewable resources and the closure of our coal-fired generating facilities.

Risk Management

We have established a risk management program that addresses both enterprise and energy commodity risks. This program oversees all the risk functions and addresses commodity price volatility, counterparty exposure, credit risk, trading controls and hedging strategies. A corporate committee, consisting of senior executives and support staff, meets regularly to assess market behavior, hedging activities and other corporate risks. Our Board is given briefings on risk management activities. Additionally, pursuant to Board policy, the Finance and Audit Committee and the Chief Executive Officer annually determine whether an external independent assessment of our risk management program shall be performed. We had an independent assessment performed in 2023 of our risk management program and have implemented various recommendations from the 2023 independent assessment and are still reviewing other recommendations.

Interest Rate Risk

We have an established risk management program to address interest rate risk. This program is designed to balance achieving the lowest costs associated with current and future debt issuances while also mitigating the impact of floating interest rates.

As of December 31, 2024, we were exposed to the risk of changes in interest rates related to our $593.5 million of variable rate debt, comprised of $142.2 million of variable rate CFC notes, $251.3 million of variable rate CoBank notes, and a $200 million variable rate Wells Fargo note. As of December 31, 2024, the weighted average interest rate on this variable rate debt was 5.88 percent.

Our objective in managing interest rate risk is to maintain a balance of fixed and variable rate debt that will lower our overall borrowing costs within reasonable risk parameters. As of December 31, 2024, we had 20.04 percent of our total debt in variable rate loans. An increase in interest rates of 100 basis points would increase our annual debt service by approximately $5.9 million.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTAL DATA

Index to Consolidated Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Members and Board of Directors of Tri-State Generation & Transmission Association, Inc.

Opinion on the Financial Statements

We have audited the accompanying Consolidated Statements of Financial Position of Tri-State Generation & Transmission Association, Inc. and subsidiaries (the "Association") as of December 31, 2024, and the related Consolidated Statements of Operations, Comprehensive Income (Loss), Equity and Cash flows for the year ended December 31, 2024, and the related notes (referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Association as of December 31, 2024, and the results of its operations and its cash flows for the period ended December 31, 2024, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Association's management. Our responsibility is to express an opinion on the Association's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Association 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 and in accordance with auditing standards generally accepted in the United States of America. 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. The Association is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Association's internal control over financial reporting. Accordingly, we express no such opinion.

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 Matters

The critical audit matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the Finance and Audit Committee and that (1) relate 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 matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Asset Retirement Obligations for Coal Mines — Refer to Notes 2 and 4 to the financial statements

Critical Audit Matter Description

The Association maintains asset retirement obligations for the final reclamation costs related to its coal mines ("AROs"). The AROs are recognized at fair value at the time of initial recognition of the obligation and capitalized as part of the related long-lived asset. The AROs are subsequently adjusted whenever there is a significant change in the estimated future costs associated with retiring the long-lived asset that would materially impact the previously estimated liability. Establishing or adjusting the value of the ARO liability requires management to make significant estimates and assumptions related to the reclamation activities, costs and related timing. The Association engaged a specialist to assist with the estimate of the AROs.

We identified AROs as a critical audit matter because of the significant estimates and assumptions made by management related to the reclamation activities, costs and related timing of the AROs. Auditing these estimates and assumptions required a high degree of auditor judgement and an increased extent of effort including for certain assumptions, the need to involve our environmental and fair value specialists.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the AROs included the following, among others:

- We tested the mathematical accuracy of management's calculation of AROs.
- With the assistance of professionals in our firm with the appropriate expertise, we inspected and evaluated the reasonableness of the results of the reclamation study, including cost estimates and total cash flows.
- With the assistance of professionals in our firm with the appropriate expertise, we conducted a regulatory search to evaluate matters that may affect the cost estimates of asset retirement obligations.
- We tested the source information underlying the present value calculation. We developed a range of independent estimates for significant inputs to the present value calculation selected by management.
- We evaluated the Association's disclosures related to AROs.

Accounting for Rate Regulation— Refer to Note 2 to the financial statements

Critical Audit Matter Description

The Association is subject to rate regulation by the Federal Energy Regulatory Commission ("FERC") as well as its Board of Directors, which has oversight with respect to electric rates to customers. Management has determined it meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based regulation. Accounting for the economic effects of rate regulation has a pervasive effect on the financial statements.

Rates are subject to regulatory rate-setting processes and are determined in order to recover the cost of service and to generate margins sufficient to meet certain financial requirements and to establish reasonable reserves. Regulatory decisions have a direct effect on the amount and recovery of allowable costs from customers through regulated rates. There is a risk that future regulatory decisions could result in the inability of the Association to recover its costs or regulatory assets.

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 certain account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future regulatory decision on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, (2) the treatment of member contract termination payments at recognition and in future periods, and (3) a refund to customers. Given that management's judgements are based on assumptions about the outcome of future regulatory decisions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the accounting for rate regulation included the following procedures, among others:

- We read relevant regulatory decisions by the Board of Directors and orders issued by the FERC, and filings made by the Association. We evaluated relevant information and compared it to certain recorded regulatory asset and liability balances for completeness.

- We evaluated management’s accounting assessment for member withdrawals. We inspected minutes of the Board of Directors to evaluate member withdrawal regulatory liabilities recognized and refunded to customers.
- For regulatory matters in process, we inspected the Association’s filings with the FERC and the filings by intervenors that may impact the Association’s future rates, for any evidence that might contradict management’s assertions.
- We inquired of management about property, plant, and equipment that may be abandoned or retired prior to the end of the useful life. We inspected minutes of the Board of Directors and regulatory orders and other filings with the FERC to identify any evidence that may contradict management’s assertion regarding probability of an abandonment.
- We evaluated the Association’s disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.

/s/ Deloitte & Touche LLP

Denver, Colorado

March 19, 2025

We have served as the Association's auditor since 2024.

Report of Independent Registered Public Accounting Firm

To the Members and the Board of Directors of Tri-State Generation and Transmission Association, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated statements of financial position of Tri-State Generation and Transmission Association, Inc. (the "Association") as of December 31, 2023, the related consolidated statements of operations, comprehensive income, equity and cash flows for each of the two years in the period ended December 31, 2023, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Association at December 31, 2023, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2023 in conformity with U.S. generally accepted accounting principles.

Basis for Opinion

These financial statements are the responsibility of the Association's management. Our responsibility is to express an opinion on the Association's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Association 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 and in accordance with auditing standards generally accepted in the United States of America. 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. The Association is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Association's internal control over financial reporting. Accordingly, we express no such opinion.

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.

/s/ Ernst & Young LLP

We have served as the Association's auditor from 1977 to 2023.

Denver, Colorado
March 15, 2024

Tri-State Generation and Transmission Association, Inc.
Consolidated Statements of Financial Position
(dollars in thousands)

	December 31, 2024	December 31, 2023
ASSETS		
Property, plant and equipment		
Electric plant		
In service	$ 5,701,182	$ 5,722,679
Construction work in progress	368,473	163,954
Total electric plant	**6,069,655**	**5,886,633**
Less allowances for depreciation and amortization	(2,838,877)	(2,739,924)
Net electric plant	**3,230,778**	**3,146,709**
Other plant	958,993	952,318
Less allowances for depreciation, amortization and depletion	(770,270)	(711,896)
Net other plant	**188,723**	**240,422**
Total property, plant and equipment	**3,419,501**	**3,387,131**
Other assets and investments		
Investments in other associations	192,680	187,684
Investments in and advances to coal mines	1,711	1,619
Restricted cash and investments	3,436	3,408
Intangible assets	39,556	1,091
Other noncurrent assets	18,407	15,264
Total other assets and investments	**255,790**	**209,066**
Current assets		
Cash and cash equivalents	229,357	106,005
Restricted cash and investments	744	605
Deposits and advances	38,180	36,364
Accounts receivable—Utility Members	85,450	101,394
Other accounts receivable	28,727	23,123
Coal inventory	95,511	54,979
Materials and supplies	110,775	106,893
Total current assets	**588,744**	**429,363**
Deferred charges		
Regulatory assets	816,541	919,483
Prepayment—NRECA Retirement Security Plan	—	5,372
Other	51,735	36,121
Total deferred charges	**868,276**	**960,976**
Total assets	**$ 5,132,311**	**$ 4,986,536**
EQUITY AND LIABILITIES		
Capitalization		
Patronage capital equity	$ 912,922	$ 984,581
Accumulated other comprehensive loss	965	(839)
Noncontrolling interest	130,498	134,269
Total equity	**1,044,385**	**1,118,011**
Long-term debt	2,857,346	2,896,506
Total capitalization	**3,901,731**	**4,014,517**
Current liabilities		
Utility Member advances	5,128	14,333
Accounts payable	158,176	123,674
Short-term borrowings	100	184,305
Accrued expenses	42,705	39,268
Current asset retirement obligations	28,451	21,635
Accrued interest	21,454	24,549
Accrued property taxes	31,363	31,986
Current maturities of long-term debt	88,658	223,523
Total current liabilities	**376,035**	**663,273**
Deferred credits and other liabilities		
Regulatory liabilities	497,028	2,317
Deferred income tax liability	12,217	15,223
Asset retirement and environmental remediation obligations	243,440	195,566
Other	93,058	84,125
Total deferred credits and other liabilities	**845,743**	**297,231**
Accumulated postretirement benefit and postemployment obligations	8,802	11,515
Total equity and liabilities	**$ 5,132,311**	**$ 4,986,536**

The accompanying notes are an integral part of these consolidated financial statements.

Tri-State Generation and Transmission Association, Inc.
Consolidated Statements of Operations
(dollars in thousands)

	For the years ended December 31,		
	2024	2023	2022
Operating revenues			
Member electric sales	$ 1,105,701	$ 1,208,352	$ 1,213,234
Non-member electric sales	196,561	145,228	163,355
Rate stabilization	211,232	47,127	95,613
Provision for rate refunds	(6,556)	94	(51)
Other	105,452	66,615	61,420
	1,612,390	**1,467,416**	**1,533,571**
Operating expenses			
Purchased power	408,796	404,876	409,513
Fuel	233,347	258,894	329,046
Production	171,879	191,095	177,413
Transmission	180,616	187,874	175,889
General and administrative	115,739	88,621	79,640
Depreciation, amortization and depletion	219,144	171,460	184,047
Coal mining	41,525	44,548	9,899
Goodwill impairment	68,223	—	—
Other	10,420	(31,341)	53,509
	1,449,689	**1,316,027**	**1,418,956**
Operating margins	**162,701**	**151,389**	**114,615**
Other income			
Interest	14,656	8,614	4,447
Capital credits from cooperatives	14,681	19,369	26,185
Other	5,795	11,447	10,027
	35,132	**39,430**	**40,659**
Interest expense			
Interest	178,387	175,557	148,609
Interest charged during construction	(12,917)	(4,800)	(1,486)
	165,470	**170,757**	**147,123**
Income tax expense (benefit)	5,320	4	(249)
Net margins including noncontrolling interest	**27,043**	**20,058**	**8,400**
Net margin attributable to noncontrolling interest	(6,502)	(9,971)	(8,400)
Net margins attributable to the Association	**$ 20,541**	**$ 10,087**	**$ —**

The accompanying notes are an integral part of these consolidated financial statements.

Tri-State Generation and Transmission Association, Inc.
Consolidated Statements of Comprehensive Income
(dollars in thousands)

	For the years ended December 31,		
	2024	2023	2022
Net margins including noncontrolling interest	$ 27,043	$ 20,058	$ 8,400
Other comprehensive income (loss):			
Unrealized gain (loss) on securities available for sale	155	127	(333)
Unrecognized actuarial gain on postretirement benefit obligation	128	757	32
Amortization of actuarial (gain) loss on postretirement benefit obligation included in net margin	(146)	(84)	102
Amortization of prior service credit on postretirement benefit obligation included in net margin	(786)	(1,637)	(1,636)
Unrecognized actuarial gain (loss) on executive benefit restoration obligation	2,950	(909)	1,740
Unrecognized prior service credit (cost) on executive benefit restoration obligation	(1,027)	—	(308)
Amortization of actuarial loss on executive benefit restoration obligation included in net margin	169	219	426
Curtailment and settlement	21	—	(187)
Amortization of prior service cost on executive benefit restoration obligation included in net margin	340	1,156	1,156
Other comprehensive income (loss)	**1,804**	**(371)**	**992**
Comprehensive income including noncontrolling interest	**28,847**	**19,687**	**9,392**
Net comprehensive income attributable to noncontrolling interest	(6,502)	(9,971)	(8,400)
Comprehensive income attributable to the Association	**$ 22,345**	**$ 9,716**	**$ 992**

The accompanying notes are an integral part of these consolidated financial statements.

Tri-State Generation and Transmission Association, Inc.
Consolidated Statements of Equity
(dollars in thousands)

	For the years ended December 31,		
	2024	2023	2022
Patronage capital equity at beginning of period	$ 984,581	$ 984,865	$ 994,865
Net margins attributable to the Association	20,541	10,087	—
Retirement of patronage capital	(92,200)	(10,371)	(10,000)
Patronage capital equity at end of period	**912,922**	**984,581**	**984,865**
Accumulated other comprehensive loss at beginning of period	(839)	(468)	(1,460)
Unrealized gain (loss) on securities available for sale	155	127	(333)
Reclassification adjustment for actuarial (gain) loss on postretirement benefit obligation included in net margin	(146)	(84)	102
Reclassification adjustment for prior service credit on postretirement benefit obligation included in net margin	(786)	(1,637)	(1,636)
Reclassification adjustment for actuarial loss on executive benefit restoration obligation included in net margin	169	219	426
Curtailment and settlement	21	—	(187)
Reclassification adjustment for prior service cost on executive benefit restoration obligation included in net margin	340	1,156	1,156
Unrecognized actuarial gain on postretirement benefit obligation	128	757	32
Unrecognized actuarial gain on executive benefit restoration obligation	2,950	(909)	1,740
Unrecognized prior service cost on executive benefit restoration obligation	(1,027)	—	(308)
Accumulated other comprehensive loss at end of period	**965**	**(839)**	**(468)**
Noncontrolling interest at beginning of period	134,269	126,180	119,100
Net comprehensive income attributable to noncontrolling interest	6,502	9,971	8,400
Equity distribution to noncontrolling interest	(10,273)	(1,882)	(1,320)
Noncontrolling interest at end of period	**130,498**	**134,269**	**126,180**
Total equity at end of period	**$ 1,044,385**	**$ 1,118,011**	**$ 1,110,577**

The accompanying notes are an integral part of these consolidated financial statements.

Tri-State Generation and Transmission Association, Inc.
Consolidated Statements of Cash Flows *(dollars in thousands)*

	For the years ended December 31,		
	2024	2023	2022
Operating activities			
Net margins including noncontrolling interest	$ 27,043	$ 20,058	$ 8,400
Adjustments to reconcile net margins to net cash provided by operating activities:			
Depreciation, amortization and depletion	219,144	171,460	184,047
Amortization of NRECA Retirement Security Plan prepayment	5,373	5,372	5,372
Amortization of debt issuance costs	2,515	2,423	3,105
Goodwill impairment	68,223	—	—
Impairment loss and other closure costs	—	261,600	29,098
Deferred impairment loss and other closure costs	—	(261,600)	(29,098)
Deposits associated with generator interconnection requests	5,444	9,880	6,716
Rate stabilization	(211,232)	(47,127)	(95,613)
Capital credit allocations from cooperatives and income from coal mines over refund distributions	(5,089)	(9,911)	(14,115)
Changes in operating assets and liabilities:			
Accounts receivable	10,340	18,019	(30,135)
Coal inventory	(40,532)	(20,256)	24,978
Materials and supplies	(3,882)	(13,380)	(6,281)
Accounts payable and accrued expenses	28,502	2,333	19,102
Accrued interest	(3,095)	(1,882)	(285)
Accrued property taxes	(623)	(4,492)	2,600
Change in environmental remediation obligation	38,337	(44,869)	44,869
Deferred membership withdrawal	709,395	—	—
Other	(7,980)	36,773	(164)
Net cash provided by operating activities	**841,883**	**124,401**	**152,596**
Investing activities			
Purchases of plant	(329,351)	(179,398)	(121,527)
Sale of electric plant	76,843	—	—
Sale of non-utility assets	11,238	—	—
Changes in deferred charges	(4,752)	4,339	(4,617)
Proceeds from other investments	—	—	94
Net cash used in investing activities	**(246,022)**	**(175,059)**	**(126,050)**
Financing activities			
Changes in Member advances	(9,205)	(2,969)	(282)
Payments of long-term debt	(375,442)	(394,447)	(232,946)
Proceeds from issuance of long-term debt	200,000	550,000	—
Debt issuance costs	(483)	(664)	(1,475)
Change in short-term borrowings, net	(184,305)	(89,297)	224,105
Retirement of patronage capital	(91,854)	(10,044)	(8,445)
Equity distribution to noncontrolling interest	(10,273)	(1,882)	(1,320)
Other	(780)	(703)	(637)
Net cash provided by (used in) financing activities	**(472,342)**	**49,994**	**(21,000)**
Net increase (decrease) in cash, cash equivalents and restricted cash and investments	**123,519**	**(664)**	**5,546**
Cash, cash equivalents and restricted cash and investments – beginning	**110,018**	**110,682**	**105,136**
Cash, cash equivalents and restricted cash and investments – ending	**$ 233,537**	**$ 110,018**	**$ 110,682**
Supplemental cash flow information:			
Cash paid for interest	$ 164,498	$ 173,147	$ 145,350
Cash paid for income taxes	$ —	$ —	$ —
Supplemental disclosure of noncash investing and financing activities:			
Change in plant expenditures included in accounts payable	$ 8,788	$ 1,005	$ (1,076)
Lease asset additions	$ 4,503	$ 469	$ —

The accompanying notes are an integral part of these consolidated financial statements.

Tri-State Generation and Transmission Association, Inc.

Notes to Consolidated Financial Statements

NOTE 1 – ORGANIZATION

Tri-State Generation and Transmission Association, Inc. (“Tri-State,” “we,” “our,” “us,” or “the Association”) is a taxable wholesale electric power generation and transmission cooperative operating on a not-for-profit basis serving large portions of Colorado, Nebraska, New Mexico and Wyoming. We were incorporated under the laws of the State of Colorado in 1952. We have three classes of membership: Class A – utility full requirements members, Class B - utility partial requirements members, and Non-Utility Members. We have 40 electric distribution member systems who are Class A members, to which we provide electric power pursuant to long-term wholesale electric service contracts. We currently have no Class B members. We have three Non-Utility Members. Our Class A members and any Class B members are collectively referred to as our "Utility Members." Our Class A members, any Class B members, and Non-Utility Members are collectively referred to as our "Members." Our rates are subject to regulation by the Federal Energy Regulatory Commission (“FERC”). On March 20, 2020, FERC accepted our stated rate (A-40) to our Class A members. On July 30, 2024, FERC issued an order accepting our A-41 formula rate to our Class A members, effective August 1, 2024, subject to refund. FERC further set our A-41 rate filing for settlement and hearing procedures and confirmed our accounting treatment, including amortization, and creation of regulatory assets for Escalante Generating Station, Rifle Generating Station, Craig Generating Station Units 2 and 3 and the New Horizon Mine environmental obligation. However, FERC did not authorize us to recover the regulatory assets that represent acquisition costs/goodwill for J.M. Shafer Generating Station and Colowyo Coal Company LP ("Colowyo Coal"). These costs were on our books prior to us becoming subject to FERC's jurisdiction. Therefore, we wrote off the J.M. Shafer Generating Station and Colowyo Coal acquisition costs/goodwill in September 2024 which resulted in the recognition of expense of $68.2 million. We recognized deferred membership withdrawal income in September 2024 as part of our rate stabilization measures, therefore, the write-off of the J.M. Shafer Generating Station and Colowyo Coal acquisition costs/goodwill resulted in no impact to our Utility Members' wholesale rate for 2024.

On May 1, 2024, United Power, Inc. (“United Power") withdrew from membership in us and terminated its wholesale electric service contract with us pursuant to Rate Schedule 281 (contract termination payment methodology) on-file with FERC and a Membership Withdrawal Agreement with United Power. United Power’s contract termination payment amount was $709.4 million. United Power paid us an exit fee in cash of $627.2 million, after a regulatory liabilities credit and relinquishing its right to any patronage capital in us resulting in a discounted patronage capital credit of $82.2 million. Such amounts remain subject to true up in accordance with Rate Schedule 281 and United Power's Membership Withdrawal Agreement. Of the total contract termination payment, $530.1 million was membership withdrawal income that was deferred as a regulatory liability. The remaining $179.3 million of United Power's contract termination payment related to a transmission credit for the portion of transmission debt allocated to United Power that was deferred as required by FERC's order on our Rate Schedule 281.

We sell a portion of our electric power to other utilities in our regions pursuant to long-term contracts and short-term sale arrangements. In 2024, 2023 and 2022, total megawatt-hours sold were 17.8, 18.2 and 18.6 million, respectively, of which 84.1, 90.7 and 88.8 percent, respectively, were sold to Utility Members. Total revenue from electric sales was $1.3 billion for 2024 and $1.4 billion for 2023 and 2022 of which 84.9, 86.2, and 82.4 percent in 2024, 2023 and 2022, respectively, was from Utility Member sales. Energy resources were provided by our generation and purchased power, of which 39.6, 48.2 and 54.3 percent in 2024, 2023 and 2022, respectively, were from our generation.

Power is provided to Utility Members at rates determined by our Board of Directors (“Board”), subject to FERC approval. Rates are designed to recover all costs and provide margins to increase Utility Members’ equity and to meet certain financial covenants, including a debt service ratio (“DSR”) requirement and equity to capitalization ratio (“ECR”) requirement.

We supply wholesale power to our Utility Members through the utilization of a portfolio of resources, including generation and transmission facilities, long-term purchase contracts and short-term energy purchases. Our generating facilities also include undivided ownership interests in jointly owned generating facilities. See Note 3—Property, Plant and Equipment. In support of our coal-fired generating facilities, we have direct ownership in coal mines.

We, including our subsidiaries, employ 1,092 people, of which 174 are subject to collective bargaining agreements. None of these agreements expire within one year.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF CONSOLIDATION: Our consolidated financial statements include the accounts of the Association, our wholly owned and majority owned subsidiaries, and certain variable interest entities for which we or our subsidiaries are the primary beneficiaries. See Note 13 - Variable Interest Entities. Our consolidated financial statements also include our undivided interests in jointly owned facilities.

All significant intercompany balances and transactions have been eliminated in consolidation. The accompanying consolidated statements have been prepared in accordance with accounting principles generally accepted in the United States (“GAAP”) as applied to regulated enterprises.

JOINTLY OWNED FACILITIES: We own undivided interests in two jointly owned generating facilities that are operated by the operating agent of each facility under joint facility ownership agreements with other utilities as tenants in common. These projects include the Yampa Project (operated by us) and the Missouri Basin Power Project (“MBPP”) (operated by Basin Electric Power Cooperative (“Basin”)). Each participant in these agreements receives a portion of the total output of the generating facilities, which approximates its percentage ownership. Each participant provides its own financing for its share of each facility and accounts for its share of the cost of each facility. The operating agent for each of these projects allocates the fuel and operating expenses to each participant based upon its share of the use of the facility. Therefore, our share of the plant asset cost, interest, depreciation and operating expenses is included in our consolidated financial statements. See Note 3 - Property, Plant and Equipment.

SEGMENT REPORTING: We were organized for the purpose of supplying wholesale power to our Utility Members and do so through the utilization of a portfolio of resources, including generation and transmission facilities, long-term purchase contracts and short-term energy purchases. In support of our coal-fired generating resources, we have direct ownership in coal mines. Our Chief Executive Officer serves as our chief operating decision maker ("CODM") who manages and reviews our operating results and allocates resources as one operating segment. Therefore, we have one reportable segment for financial reporting purposes. Our significant segment expenses are regularly provided to our CODM and include purchased power, fuel, production, transmission, general and administrative, depreciation, amortization and depletion, coal mining, goodwill impairment, and interest expense, net of interest charged during construction. Our not significant segment expenses include other operating expenses and income tax expense. As we have only one operating segment, these values agree to those disclosed in our Consolidated Statements of Operations.

USE OF ESTIMATES: The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results may differ from those estimates.

IMPAIRMENT EVALUATION: Long-lived assets (property, plant and equipment, intangible assets, investments and preliminary surveys and investigation costs) that are held and used are evaluated for impairment whenever events or changes in circumstances indicate the carrying value of an asset may not be recoverable. An impairment loss is recognized when estimated undiscounted cash flows expected to result from the use of the asset plus net proceeds expected from disposition of the asset (if any) are less than the carrying value of the asset. When an impairment loss is recognized, the carrying amount of the asset is reduced to its estimated fair value based on quoted market prices or other valuation techniques. In 2024, we recognized an impairment loss of $68.2 million associated with the write off of the J.M. Shafer Generating Station and Colowyo Coal acquisition costs/goodwill. In 2023, as part of preparing our financial statements, we recognized an impairment loss of $261.6 million associated with the planned early retirement of Craig Generating Station Units 2 and 3. In 2022, we recognized an impairment loss of $3.7 million associated with the early retirement of the Rifle Generating Station. We also recognized an impairment loss of $25.4 million associated with additional asset retirement obligations at the Nucla and Escalante Generating Stations related to a change in cost estimates. Our 2023 and 2022 impairment losses were deferred in accordance with the accounting requirements related to regulated operations at the discretion of our Board and subject to FERC approval, if applicable. See Note 2 - Accounting for Rate Regulation.

VARIABLE INTEREST ENTITIES: We evaluate our arrangements and relationships with other entities, including our investments in other associations in accordance with the accounting standard related to consolidation of variable interest entities. This guidance requires us to identify variable interests (contractual, ownership or other financial interests) in other entities and whether any of those entities in which we have a variable interest meet the criteria of a variable interest entity. An entity is considered to be a variable interest entity 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. In making this assessment, we consider the potential that our arrangements and relationships with other entities provide subordinated financial support, the potential for us to absorb losses or rights to residual returns of an entity, the ability to directly or indirectly make decisions about the entity's activities and other factors. If an entity that we have a variable interest in meets the criteria of a variable interest entity, we must determine whether we are the primary beneficiary of that entity. The primary beneficiary is the entity that has the power to direct the activities of the variable interest entity that most significantly impact the variable interest entity's economic performance, and the obligation to absorb losses or the right to receive benefits from the variable interest entity that could be potentially significant to the variable interest entity. If we are determined to be the primary beneficiary of (has controlling financial interest in) a variable interest entity, then we would be required to consolidate that entity. In certain situations, it may be determined that power is shared among multiple unrelated parties such that no one party has the power to direct the activities of a variable interest entity that most significantly impact the variable interest entity's economic performance (decisions about those activities require the consent of each of the parties sharing power). In accordance with the accounting guidance prescribed by consolidation of variable interest entities, if the determination is made that power is shared among multiple unrelated parties, then no party is the primary beneficiary. See Note 13 - Variable Interest Entities.

ACCOUNTING FOR RATE REGULATION: In accordance with the accounting requirements related to regulated operations, some revenues and expenses have been deferred at the discretion of our Board, subject to FERC approval, if based on regulatory orders or other available evidence, it is probable that these amounts will be refunded or recovered through future rates. Regulatory assets are costs we expect to recover from our Utility Members based on rates approved by the applicable authority. Regulatory liabilities represent probable future reductions in rates associated with amounts that are expected to be refunded to our Utility Members based on rates approved by the applicable authority. Amounts that are no longer expected to be refunded to our Utility Members are recognized in margins. We recognize regulatory assets as expenses and regulatory liabilities as operating revenue, other income, or a reduction in expense concurrent with their recovery through rates. As a cooperative, we don't earn a rate of return on regulatory items.

Regulatory assets and liabilities are as follows (dollars in thousands):

	December 31, 2024	December 31, 2023
Regulatory assets		
Deferred income tax expense (1)	$ 12,217	$ 15,223
Deferred prepaid lease expense – Springerville Unit 3 Lease (2)	72,260	74,551
Goodwill – J.M. Shafer (3)	—	37,749
Goodwill – Colowyo Coal (4)	—	33,062
Deferred debt prepayment transaction costs (5)	97,789	106,417
Deferred Holcomb expansion impairment loss (6)	70,121	74,795
New Horizon Mine environmental obligation (7)	44,121	44,869
Unrecovered plant (8)	520,033	532,817
Total regulatory assets	**816,541**	**919,483**
Regulatory liabilities		
Interest rate swap - realized gain (9) and other	1,390	1,854
Membership withdrawal (10)	319,368	463
Withdrawal related transmission credit (11)	176,270	—
Total regulatory liabilities	**497,028**	**2,317**
Net regulatory asset	**$ 319,513**	**$ 917,166**

(1) A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be received or settled through future rate revenues.
(2) Represents deferral of the loss on acquisition related to the Springerville Generating Station Unit 3 ("Springerville Unit 3") prepaid lease expense upon acquiring a controlling interest in the Springerville Unit 3 Partnership LP ("Springerville Partnership") in 2009. The regulatory asset for the deferred prepaid lease expense is being amortized to depreciation, amortization and depletion expense in the amount of $2.3 million annually through the 47-year period ending in 2056 and recovered from our Utility Members in rates.
(3) Represented acquisition costs related to our acquisition of an entity that owned J.M. Shafer Generating Station in December 2011. In September 2024, we wrote off the remaining $35.8 million balance of J.M. Shafer Generating Station

acquisition costs as they are no longer probable to be recovered, offset with recognition of previously deferred membership withdrawal income. See Note 1 - Organization.

(4) Represented acquisition costs related to our acquisition of Colowyo Coal in December 2011. In September 2024, we wrote off the remaining $32.4 million balance of Colowyo Coal acquisition costs as they are no longer probable to be recovered, offset with recognition of previously deferred membership withdrawal income. See Note 1 - Organization.

(5) Represents transaction costs that we incurred related to the prepayment of our long-term debt in 2014. These costs are being amortized to depreciation, amortization and depletion expense in the amount of $8.6 million annually over the 21.4-year period ending in 2036 and recovered from our Utility Members in rates.

(6) Represents deferral of the impairment loss related to development costs, including costs for the option to purchase development rights for the expansion of the Holcomb Generating Station. The regulatory asset for the deferred impairment loss is being amortized to other operating expenses in the amount of $4.7 million annually over the 20-year period ending in 2039 and recovered from our Utility Members in rates.

(7) Represents $44.9 million of New Horizon Mine environmental obligation expense that was recognized as a regulatory item in 2023. The regulatory asset for the deferred environmental obligation expense is being amortized to expense in the amount of $1.8 million annually over 25 years ending in 2049 and recovered from our Utility Members through rates.

(8) Represents deferral of the impairment losses and other closure costs related to the early retirement of the Escalante, Rifle and Craig Generating Station Units 2 and 3. The deferred impairment loss for Escalante Generating Station is being amortized to depreciation, amortization and depletion expense in the amount of $12.2 million annually over the 25-year period ending in 2045, which was the depreciable life of Escalante Generating Station, and recovered from our Utility Members through rates. The deferred impairment loss for Rifle Generating Station is being amortized to depreciation, amortization and depletion expense in the amount of $0.6 million annually through 2028, which was the depreciable life of the Rifle Generating Station, and recovered from our Utility Members in rates. We recognized the early retirement of Craig Station Units 2 and 3. We recognized an impairment loss of $261.6 million and deferred the loss in accordance with accounting for rate regulation. The deferred impairment loss will be amortized to depreciation, amortization and depletion expense beginning in October 2028 through 2039 for Craig Generating Station Unit 2 and January 2030 through 2043 for Craig Generating Station Unit 3 and will be recovered from our Utility Members through future rates. These amortization periods were the depreciable lives of Craig Generating Station Units 2 and 3. The annual amortization is expected to approximate the former annual Craig Generating Station Units 2 and 3 depreciation for the remaining life of the asset.

(9) Represents deferral of a realized gain of $4.6 million related to the October 2017 settlement of a forward starting interest rate swap. This realized gain was deferred as a regulatory liability and is being amortized to interest expense over the 12-year term of the First Mortgage Obligations, Series 2017A and refunded to Utility Members through reduced rates when recognized in future periods.

(10) Represents the remaining balance of the deferred recognition of other operating revenues related to the withdrawal of former Utility Members from membership in us. On May 1, 2024, United Power withdrew from membership in us and United Power's contract termination payment amount was $709.4 million, of which $530.1 million was membership withdrawal income that was deferred by our Board as a regulatory liability. The deferred membership withdrawal income will be refunded to Utility Members through reduced rates when recognized in operating revenues in future periods with the oldest vintage year first. During 2024, $211.2 million was recognized in operating revenues as part of our rate stabilization measures. See Note 10 - Revenue.

(11) Represents the remaining amount of United Power's transmission credit related to taking transmission service from us. A portion of a withdrawing Utility Member's contract termination payment is allocated to transmission debt that is deferred as required by FERC order on Rate Schedule 281. The transmission credit, plus interest at FERC's prescribed interest rate, is refunded to the former Utility Member on a monthly basis if the former Utility Member takes transmission service from us and amortized on a straight-line basis over the remaining term. If the former Utility Member's transmission bill for a given month is lower than the credit amount that would be due, the difference is forfeited by the former Utility Member.

ELECTRIC PLANT AND DEPRECIATION: Electric plant is stated at cost. The cost of internally constructed assets includes payroll, overhead costs and interest charged during construction. Interest rates charged during construction were 5.8 percent for 2024, 5.2 percent for 2023 and 2.3 percent for 2022. During 2022, we transitioned from using the "Indirect Costs" ("IDC") rate to the FERC prescribed "Allowance For Funds Used During Construction" ("AFUDC") rate. AFUDC is defined as the gross allowance for borrowed funds used during construction. The AFUDC rate is calculated with the assumption that short-term debt is the first source of funds used for construction. Any construction not covered by the short-term debt is then assumed to be covered by long-term debt. The AFUDC rate varies from the IDC rate, which assumes that total debt was used to cover construction costs. The amount of interest capitalized during construction was $12.9, $4.8 and $1.5 million during 2024, 2023 and 2022, respectively. At the time that units of electric plant are retired, original cost and cost of removal, net of the salvage value, are charged to the allowance for depreciation. Replacements of electric plant that involve less than a designated unit value are charged to maintenance expense when incurred. Electric plant is depreciated based upon estimated depreciation rates and useful lives that are periodically re-evaluated. See Note 3 - Property, Plant and Equipment.

COAL RESERVES AND DEPLETION: Coal reserves are recorded at cost. Depletion of coal reserves is computed using the units-of-production method utilizing only proven and probable reserves.

LEASES: We determine if an arrangement is a lease upon commencement of the contract. If an arrangement is determined to be a long-term lease (greater than 12 months), we recognize a right-of-use asset and lease liability based on the present value of the future minimum lease payments over the lease term at the commencement date. As most of our leases do not provide an implicit rate, we use our incremental borrowing rate based on the information available at commencement date in determining the present value of future payments. Our lease terms may also include options to extend or terminate the lease when it is reasonably certain that we will exercise those options. Lease expense for minimum lease payments is recognized on a straight-line basis over the lease term. Right-of-use assets are included in other deferred charges, the current portion of lease liabilities is included in accrued expenses and the long-term portion of lease liabilities is included in other deferred credits and other liabilities on our consolidated statements of financial position. See Note 11 - Leases.

We have elected to apply the short-term lease exception for contracts that have a lease term of twelve months or less and do not include an option to purchase the underlying asset. Therefore, we do not recognize a right-of-use asset or lease liability for such contracts. We recognize short-term lease payments as expense on a straight-line basis over the lease term. Variable lease payments that do not depend on an index or rate are recognized as incurred.

INVESTMENTS IN OTHER ASSOCIATIONS: Investments in other associations include investments in the patronage capital of other cooperatives and other required investments in the organizations. Our investment in a cooperative increases when a cooperative allocates patronage capital credits to us, and it decreases when we receive a cash retirement of the allocated capital credits from the cooperative. A cooperative allocates its patronage capital credits to us based upon our patronage (amount of business done) with the cooperative.

Investments in other associations are as follows (dollars in thousands):

	December 31, 2024	December 31, 2023
Basin Electric Power Cooperative	$ 140,025	$ 135,652
CoBank, ACB	19,500	18,809
National Rural Utilities Cooperative Finance Corporation - patronage capital	12,599	12,451
National Rural Utilities Cooperative Finance Corporation - capital term certificates	15,054	15,054
Other	5,502	5,718
Investments in other associations	**$ 192,680**	**$ 187,684**

Our investments in other associations are considered equity securities without readily determinable fair values, and as such are measured at cost minus impairment. We have evaluated these investments for indicators of impairment. There were no impairments of these investments recognized during 2024, 2023 or 2022.

CASH, CASH EQUIVALENTS AND RESTRICTED CASH AND INVESTMENTS: We consider highly liquid investments with an original maturity of three months or less to be cash equivalents. The fair value of cash equivalents approximates their carrying values due to their short-term maturity.

Restricted cash and investments represent funds designated by our Board for specific uses and funds restricted by contract or other legal reasons. A portion of the funds have been restricted by contract and are expected to be settled within one year. These funds are therefore classified as current on our consolidated statements of financial position. The other funds are restricted by contract or other legal reasons and are expected to be settled beyond one year. These funds are classified as noncurrent and are included in other assets and investments on our consolidated statements of financial position.

The following table provides a reconciliation of cash, cash equivalents and restricted cash and investments reported within our consolidated statements of financial position that sum to the total of the same such amount shown in our consolidated statements of cash flows (dollars in thousands):

	December 31, 2024	December 31, 2023
Cash and cash equivalents	$ 229,357	$ 106,005
Restricted cash and investments - current	744	605
Restricted cash and investments - noncurrent	3,436	3,408
Cash, cash equivalents and restricted cash and investments	**$ 233,537**	**$ 110,018**

MARKETABLE SECURITIES: We hold marketable securities in connection with the directors' and executives' elective deferred compensation plans which consist of investments in stock funds, bond funds and money market funds. These securities are measured at fair value on a recurring basis with changes in fair value recognized in earnings. The estimated fair value of the investments is based upon their active market value (Level 1 inputs) and is included in other noncurrent assets on our consolidated statements of financial position. The cost and estimated fair value of the investments as of December 31, 2024 were $0.6 million and $0.6 million, respectively. The cost and estimated fair value of the investments as of December 31, 2023 were $0.6 million and $0.5 million, respectively.

INVENTORIES: Effective August 1, 2024, we changed our inventory cost method to average cost for all coal inventories previously carried at LIFO (last-in, first-out) cost. Management determined that this change in accounting principle is preferable because the average cost method more closely reflects the physical flow of inventories, improves comparability of our operating results with its industry peers, and provides an increased level of consistency in the measurement of inventories in our consolidated financial statements. Coal inventories at our owned generating facilities are stated at average cost as of August 1, 2024 and were $65.6 million as of December 31, 2024. Prior to August 1, 2024, coal inventories at our owned generating facilities were stated at LIFO cost and were $29.0 million as of December 31, 2023. The remaining coal inventories, other fuel, and materials and supplies inventories are stated at average cost.

OTHER DEFERRED CHARGES: We make expenditures for preliminary surveys and investigations for the purpose of determining the feasibility of contemplated generation and transmission projects. If construction results, the preliminary survey and investigation expenditures will be reclassified to electric plant - construction work in progress. If the work is abandoned, the related preliminary survey and investigation expenditures will be charged to the appropriate operating expense account, or the expense could be deferred as a regulatory asset to be recovered from our Utility Members through rates subject to approval by our Board and FERC.

We make advance payments to the operating agents of jointly owned facilities to fund our share of costs expected to be incurred under each project, including MBPP – Laramie River Generating Station and Yampa Project – Craig Generating Station Units 1 and 2. We also make advance payments to the operating agent of Springerville Unit 3.

A right-of-use asset represents a lessee's right to control the use of the underlying asset for the lease term. Right-of-use assets are included in other deferred charges and presented net of accumulated amortization. See Note 11 - Leases.

Other deferred charges are as follows (dollars in thousands):

	December 31, 2024	December 31, 2023
Preliminary surveys and investigations	$ 12,192	$ 12,845
Lease right-of-use assets	10,177	6,477
Advances to operating agents of jointly owned facilities	7,502	2,750
Other	21,864	14,049
Total other deferred charges	**$ 51,735**	**$ 36,121**

DEBT ISSUANCE COSTS: We account for debt issuance costs as a direct deduction of the associated long-term debt carrying amount consistent with the accounting for debt discounts and premiums. Deferred debt issuance costs are amortized to interest expense using an effective interest method over the life of the respective debt.

ASSET RETIREMENT AND ENVIRONMENTAL REMEDIATION OBLIGATIONS: We account for current obligations associated with the future retirement of tangible long-lived assets and environmental remediation in accordance with the accounting guidance relating to asset retirement and environmental obligations. This guidance requires that legal obligations associated with the retirement of long-lived assets be recognized at fair value at the time the liability is incurred and capitalized as part of the related long-lived asset. Over time, the liability is adjusted to its present value by recognizing accretion expense, and the capitalized cost of the long-lived asset is depreciated in a manner consistent with the depreciation of the underlying physical asset. In the absence of quoted market prices, we determine fair value by using present value techniques in which estimates of future cash flows associated with retirement activities are discounted using a credit adjusted risk-free rate and a market risk premium. As changes in estimates occur, such as mine plans, estimated costs, and timing of the performance of reclamation activities, we make revisions to the asset and obligation at the appropriate discount rate. Upon settlement of an asset retirement obligation, we apply payment against the estimated liability and incur a gain or loss if the actual retirement costs differ from the estimated recorded liability.

Environmental remediation costs are accrued based on management's best estimate at the end of each period of the costs expected to be incurred. Such cost estimates may include ongoing care, maintenance and monitoring costs. Changes in remediation estimates are reflected in earnings in the period an estimate is revised. Estimates of future expenditures for environmental remediation obligations are not discounted. See Note 4 - Asset Retirement and Environmental Remediation Obligations.

OTHER DEFERRED CREDITS AND OTHER LIABILITIES: In 2015, we renewed transmission right-of-way easements on tribal nation lands where certain of our electric transmission lines are located. We will pay $25.4 million for these easements from 2025 through the individual easement terms ending between 2036 and 2040. The present value of the remaining easement payments was $18.5 million and $17.9 million as of December 31, 2024 and December 31, 2023, respectively, which is recorded as other deferred credits and other liabilities.

OATT deposits represent refundable transmission customer deposits related to interconnection and transmission requests from third parties. An OATT deposit is refundable as provided in our Open Access Transmission Tariff.

Financial liabilities-reclamation represent financial obligations that we have for our share of the reclamation costs at jointly owned facilities in which we have undivided interests.

A lease liability represents a lessee's obligation to make lease payments over the lease term. The long-term portion of our lease liabilities are included in other deferred credits and other liabilities and the current portion of our lease liabilities are included in current liabilities.

A contract liability represents an entity's obligation to transfer goods or services to a customer for which the entity has received consideration from the customer. We have received deposits from others and these deposits are reflected in contract liabilities (unearned revenue) until recognized in other operating revenues over the life of the agreement. We have received deposits from various parties and those that may still be required to be returned are a liability and these are reflected in customer deposits.

The following other deferred credits and other liabilities are reflected on our consolidated statements of financial position (dollars in thousands):

	December 31, 2024	December 31, 2023
OATT deposits	$ 32,587	$ 27,872
Transmission easements	$ 18,517	$ 17,862
Customer deposits	14,955	12,091
Financial liabilities - reclamation	11,077	16,895
Lease liabilities - noncurrent	5,715	1,396
Contract liabilities (unearned revenue) - noncurrent	3,480	3,125
Other	6,727	4,884
Total other deferred credits and other liabilities	**$ 93,058**	**$ 84,125**

PATRONAGE CAPITAL: Our net margins are treated as advances of capital from our Members and are allocated to our Utility Members on the basis of their electricity purchases from us and to our Non-Utility Members as provided in their respective membership agreements. Margins not yet distributed to Members constitute patronage capital. Patronage capital is held for the account of our Members and is distributed through patronage capital retirements when our Board deems it appropriate to do so, subject to debt instrument restrictions.

ELECTRIC SALES REVENUE: Revenue from electric energy deliveries is recognized when delivered. See Note 10 - Revenue.

OTHER OPERATING REVENUE: Other operating revenue consists primarily of wheeling, transmission, and lease revenue. See Note 10 - Revenue.

INCOME TAXES: We are a taxable cooperative subject to federal and state taxation. As a taxable electric cooperative, we are allowed a tax exclusion for margins allocated as patronage capital. We utilize the liability method of accounting for income taxes which requires that deferred tax assets and liabilities be determined based on the expected future income tax consequences of events that have been recognized in the consolidated financial statements. We and our subsidiaries use the flow-through method for recognizing deferred income taxes whereby changes in deferred tax assets or liabilities result in the establishment of a regulatory asset or liability, as approved by our Board and FERC. A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be settled or received through future rate revenues. Under this regulatory accounting approach, any income tax expense or benefit on our consolidated statements of operation includes only the current portion. See Note 9 - Income Taxes.

INTERCHANGE POWER: We occasionally engage in interchanges, or non-cash swapping, of energy. Based on the assumption that all energy interchanged will eventually be received or delivered in-kind, interchanged energy is generally valued at the average cost of fuel to generate power. Additionally, portions of the energy interchanged are valued per contract with the utility involved in the interchange. When we are in a net energy advance position, the advanced energy balance is recorded as an asset. If we owe energy, the net energy balance owed to others is recorded as a liability. The net activity for the year is included in purchased power expense. The interchange liability balance of $3.7 million and $4.1 million as of December 31, 2024 and 2023, respectively, is included in accounts payable. The net interchange activity recorded in purchased power expense was a credit of $0.8 million in 2024, a credit of $2.1 million in 2023 and an expense of $1.5 million in 2022.

ACCOUNTING PRONOUNCEMENTS - NOT YET ADOPTED: In November 2024, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2024-03, Income Statement - Reporting Comprehensive Income - Expense Disaggregation Disclosures. ASU 2024-03 requires a public business entity to disclose in a tabular format, on an annual and interim basis, purchases of inventory, employee compensation, depreciation, intangible asset amortization and depletion for each income statement line item that contains those expenses in the notes to the financial statements. Specified expenses, gains and losses that are already disclosed under existing GAAP are also required to be included in the disaggregated income statement expense line item disclosures and any remaining amounts need to be described qualitatively. Separate disclosures of total selling expenses and an entity's definition of those expenses are also required. ASU 2024-03 is effective for fiscal years beginning after December 15, 2026, and interim periods within fiscal years beginning after December 15, 2027. Early adoption is permitted. Entities may apply the guidance prospectively or retrospectively.

In December 2023, the FASB issued ASU 2023-09 – Income Taxes (Topic 740): Improvements to Income Tax Disclosures. The purpose of ASU 2023-09 is to enhance the transparency and decision usefulness of income tax disclosures by providing additional information related to the following:

(1) Rate reconciliation: ASU 2023-09 requires a tabular rate reconciliation using both percentages and dollar amounts of the reported income tax expense (or benefit) from continuing operations to the product of income (or loss) from continuing operating before income taxes and the applicable statutory federal income tax rate of the county of domicile using specific categories. The following specific categories are required to be disclosed in the rate reconciliation; state and local income tax (qualitative disclosure required for states that make up over 50% of this category), foreign tax effect, effect of changes in tax laws or rates enacted in the current period, effect of cross-border tax laws, tax credits, changes in valuation allowances, nontaxable or nondeductible items, changes in unrecognized tax benefits, and any other item that meets the 5 percent threshold.

(2) Income taxes paid: ASU 2023-09 requires all reporting entities to disclose the year-to-date amount of income taxes paid (net of refunds received) disaggregated by federal, state, and foreign jurisdictions. It also requires additional disaggregation of income taxes paid to an individual jurisdiction equal to or greater than 5 percent of total income taxes paid (net of refunds). Entities are required to disclose pre-tax income (or loss) from continuing operations disaggregated by domestic and foreign along with income tax expense (or benefit) disaggregated by federal, state, and foreign components.

ASU 2023-09 is effective for public business entities for annual periods beginning after December 15, 2024, with early adoption and retrospective or prospective application permitted. We have evaluated the impact of ASU 2023-09 and believe that the adoption of this update will not have a material impact on our consolidated financial statement disclosures.

RECLASSIFICATIONS: Certain reclassifications have been made to the prior year financial information to conform to the 2024 presentation.

NOTE 3 – PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment consists of electric plant and other plant. Both of these are discussed below and are included on our consolidated statements of financial position.

ELECTRIC PLANT: As of December 31, 2024, our investment in electric plant and the related annual rates of depreciation or amortization calculated using the straight-line method are as follows (dollars in thousands):

	Annual Depreciation Rate			Plant In Service	Accumulated Depreciation	Net Book Value
Generation plant	1.14 %	to	4.14 %	$ 3,100,656	$ (1,744,837)	$ 1,355,819
Transmission plant	1.17 %	to	1.84 %	1,933,206	(715,505)	1,217,701
General plant	1.20 %	to	11.60 %	426,615	(279,678)	146,937
Other	2.75 %	to	10.00 %	240,705	(98,857)	141,848
Electric plant in service (at cost)				**$ 5,701,182**	**$ (2,838,877)**	**2,862,305**
Construction work in progress						368,473
Electric plant						**$ 3,230,778**

As of December 31, 2023, our investment in electric plant and the related annual rates of depreciation or amortization calculated using the straight-line method are as follows (dollars in thousands):

	Annual Depreciation Rate			Plant In Service	Accumulated Depreciation	Net Book Value
Generation plant	0.89 %	to	6.27 %	$ 3,082,133	$ (1,669,941)	$ 1,412,192
Transmission plant	1.11 %	to	2.09 %	1,983,629	(708,412)	1,275,217
General plant	1.46 %	to	9.53 %	410,856	(266,013)	144,843
Other	2.75 %	to	10.00 %	246,061	(95,558)	150,503
Electric plant in service (at cost)				**$ 5,722,679**	**$ (2,739,924)**	**2,982,755**
Construction work in progress						163,954
Electric plant						**$ 3,146,709**

As of December 31, 2024, we had $108.0 million of commitments to complete construction projects, of which approximately $57.0, $31.0 and $20.0 million are expected to be incurred in 2025, 2026 and 2027, respectively.

JOINTLY OWNED FACILITIES: Our share in each jointly owned facility is as follows as of December 31, 2024 (these electric plant in service, accumulated depreciation and construction work in progress amounts are included in the electric plant table above) (dollars in thousands):

	Tri-State Share	Electric Plant in Service	Accumulated Depreciation	Construction Work In Progress
Yampa Project - Craig Generating Station Units 1 and 2	24.00 %	$ 392,510	$ 367,910	$ —
MBPP - Laramie River Generating Station	28.50 %	542,872	354,346	973
Total		**$ 935,382**	**$ 722,256**	**$ 973**

OTHER PLANT: Other plant consists of mine assets (discussed below) and non-utility assets which consist of facilities not in service, land and irrigation equipment. The depreciation basis for all other plant assets is the straight-line method.

We own 100 percent of Elk Ridge Mining and Reclamation, LLC ("Elk Ridge"), organized for the purpose of acquiring coal reserves and supplying coal to us. Elk Ridge is the owner of the Colowyo Mine, a surface coal mine near Craig, Colorado, and the New Horizon Mine near Nucla, Colorado. The New Horizon Mine is in post-reclamation monitoring and no longer produces coal. The expenses related to the Colowyo Mine coal used by us are included in fuel expense on our consolidated statements of operations.

Other plant assets are as follows (dollars in thousands):

	December 31, 2024	December 31, 2023
Colowyo Mine assets	$ 403,482	$ 396,441
New Horizon Mine assets	6,287	6,448
Accumulated depreciation and depletion	(242,654)	(184,239)
Net mine assets	**167,115**	**218,650**
Non-utility assets	549,224	549,430
Accumulated depreciation	(527,616)	(527,658)
Net non-utility assets	**21,608**	**21,772**
Net other plant	**$ 188,723**	**$ 240,422**

NOTE 4 – ASSET RETIREMENT AND ENVIRONMENTAL REMEDIATION OBLIGATIONS

Coal mines: We have asset retirement obligations for the final reclamation costs and environmental obligations for post-reclamation monitoring related to the Colowyo Mine and the New Horizon Mine. The New Horizon Mine is currently in post-reclamation monitoring. Two pits at the Colowyo Mine are in final reclamation with the other pit still being actively mined.

Generation: We have asset retirement obligations related to equipment, dams, ponds, wells, ash landfill and underground storage tanks at our generating facilities.

Aggregate carrying amounts of asset retirement obligations and environmental remediation obligations are as follows (dollars in thousands):

	2024	2023
Obligations at beginning of period	$ 217,201	$ 187,007
Liabilities incurred	41,747	—
Liabilities settled	(9,791)	(5,711)
Accretion expense	7,725	5,298
Gain on settlement	(207)	—
Change in estimate	15,216	30,607
Total obligations at end of period	**$ 271,891**	**$ 217,201**
Less current obligations at end of period	(28,451)	(21,635)
Long-term obligations at end of period	**$ 243,440**	**$ 195,566**

During 2024, we increased the asset retirement obligation related to one pit at the Colowyo Mine by $12.6 million due to revised cost estimates and timing adjustments. In the fourth quarter of 2024, we increased the environmental remediation obligation at the New Horizon Mine by $2.6 million due to revised cost estimates. The New Horizon Mine environmental remediation liability balance is $69.1 million as of December 31, 2024. Of this amount, $24.7 million is recorded on a discounted basis, using a discount rate of 6.73 percent, with total estimated undiscounted future cash outflows of $36.6 million. Environmental obligation expense is included in other operating expenses on our consolidated statement of operations. In the fourth quarter of 2023, we reversed the $44.9 million of environmental obligation expense related to New Horizon Mine that was recorded in 2022 as a regulatory item to be amortized to expense over 25 years and recovered from our Utility Members through rates. In the fourth quarter of 2024, we recognized an environmental remediation obligation at the Colowyo Mine of $35.8 million. Of this amount, $3.0 million is recorded on a discounted basis, using a discount rate of 6.73 percent, with total estimated undiscounted future cash outflows of $4.4 million. During the third quarter of 2024, we recognized a change in estimate related to the Colowyo Mine asset retirement obligation due to a change in the planned timing of full reclamation to 2025 and an updated cost estimate. We continue to evaluate the New Horizon Mine and Colowyo Mine post reclamation obligations and will make adjustments to these obligations as needed.

We also have asset retirement obligations with indeterminate settlement dates. These are made up primarily of obligations attached to transmission and other easements that are considered by us to be operated in perpetuity and therefore the measurement of the obligation is not possible. A liability will be recognized in the period in which sufficient information exists to estimate a range of potential settlement dates as is needed to employ a present value technique to estimate fair value.

NOTE 5 – CONTRACT ASSETS AND CONTRACT LIABILITIES

Contract Assets

A contract asset represents an entity's right to consideration in exchange for goods or services that the entity has transferred to a customer when that right is conditioned on something other than the passage of time (for example, the entity's future performance). We have no contract assets as of December 31, 2024 and December 31, 2023.

Accounts Receivable

We record accounts receivable for our unconditional rights to consideration arising from our performance under contracts with our Members and other parties. Uncollectible amounts, if any, are identified on a specific basis and charged to expense in the period determined to be uncollectible. See Note 10 - Revenue.

Contract liabilities (unearned revenue)

A contract liability represents an entity's obligation to transfer goods or services to a customer, for which the entity has received consideration from the customer. We have received deposits from others, and these deposits are reflected in unearned revenue (included in other deferred credits and other liabilities on our consolidated statements of financial position) before revenue is recognized, resulting in contract liabilities. We recognized $1.2 million of this unearned revenue in 2024 in other operating revenues on our consolidated statements of operations.

Our contract assets, accounts receivable and liabilities consist of the following (dollars in thousands):

	December 31, 2024	December 31, 2023
Accounts receivable - Members	**$ 85,450**	**$ 101,394**
Other accounts receivable - trade:		
Non-member electric sales	21,035	9,657
Other	3,642	11,077
Total other accounts receivable - trade	**24,677**	**20,734**
Other accounts receivable - nontrade	4,050	2,389
Total other accounts receivable	**$ 28,727**	**$ 23,123**
Contract liabilities (unearned revenue)	**$ 3,480**	**$ 4,159**

NOTE 6 – LONG-TERM DEBT

We have $2.9 billion of long-term debt which consists of mortgage notes payable, pollution control revenue bonds and the Springerville certificates. The mortgage notes payable and pollution control revenue bonds are secured on a parity basis by a Master First Mortgage Indenture, Deed of Trust and Security Agreement ("Master Indenture"). Substantially all our assets, rents, revenues and margins are pledged as collateral. The Springerville certificates are secured by the assets of Springerville Unit 3. All long-term debt contains certain restrictive financial covenants, including a DSR requirement on an annual basis and an ECR requirement of at least 18 percent at the end of each fiscal year. Other than long-term debt for the Springerville certificates that has a DSR requirement of at least 1.02 on an annual basis, all other long-term debt contains a DSR requirement of at least 1.10 on an annual basis. A DSR below 1.025 under the Master Indenture would require us to transfer all cash to a special fund managed by the trustee of the Master Indenture.

We have a secured revolving credit facility with National Rural Utilities Cooperative Finance Corporation ("CFC"), as lead arranger and administrative agent, in the amount of $520 million ("2022 Revolving Credit Agreement") that expires on April 25, 2027. We had no outstanding borrowings under the 2022 Revolving Credit Agreement as of December 31, 2024. As of December 31, 2024, we had $517 million in availability (including $500 million under the commercial paper back-up sublimit) under the 2022 Revolving Credit Agreement, due to an $3 million outstanding letter of credit for the benefit of the Rural Utilities Service ("RUS").

On May 8, 2024, we used a portion of the cash from United Power's contract termination payment to pay off the $150 million balance on our 2023 multiple advance rate term loan agreement with CoBank, as administrative agent.

We entered into both a loan agreement and security agreement, dated October 1, 2024, with RUS, a part of the U.S. Department of Agriculture ("USDA"), for a $75 million zero percent interest loan. The loan agreement includes financial DSR requirements in line with the covenants contained in our Master Indenture. This loan was provided by RUS as part of the Rural Energy Savings Program pursuant to the Farm Security and Rural Investment Act of 2002. We can draw up to $50 million of this loan as part of our new Electrify and Save® On-Bill Repayment Program that allows our Utility Members' customers to install energy efficiency measures, at no upfront cost, and repay over time through their monthly utility bill from our Utility Members the costs of the measures and installation, at low interest rates. The remaining $25 million may be used as permitted in our work plan with RUS. Other than a special draw of $3 million that is due at maturity, each draw must be repaid within 10 years. The loan has a final maturity of October 1, 2044 and is not secured under our Master Indenture, but rather secured by certain depository accounts related to the On-Bill Repayment Program and certain rights in our On-Bill Repayment Program. As of December 31, 2024, we had no draws under this loan.

As a requirement of the loan from RUS, we must maintain a letter of credit for the benefit of RUS equal to 50 percent of the amount drawn and outstanding from the loan. We have provided RUS a letter of credit for $3 million issued under our 2022 Revolving Credit Agreement for expected upcoming draws as part of our On-Bill Repayment Program.

Our First Mortgage Bonds, Series 2014E-1 with $128 million outstanding matured on November 1, 2024. The bonds were paid off in full at maturity on November 1, 2024.

On December 12, 2024, we entered into a three-year, $200 million variable interest rate loan with Wells Fargo Bank, National Association. On the date of closing, we drew the full $200 million from the loan. The loan will support the construction costs of the Axial Basin Solar and Dolores Canyon Solar projects.

Long-term debt, including applicable terms and interest rates as of December 31, 2024, consists of the following (dollars in thousands):

	December 31, 2024	December 31, 2023
Mortgage notes payable		
2.32% to 6.44% CFC, due through 2050	$ 163,010	$ 177,260
4.06% to 4.43% CoBank, ACB, due through 2042	141,793	159,736
First Mortgage Obligations, Series 2017A, Tranche 1, 3.34%, due through 2029	60,000	60,000
First Mortgage Obligations, Series 2017A, Tranche 2, 3.39%, due through 2029	60,000	60,000
First Mortgage Bonds, Series 2016A, 4.25% due 2046	228,783	228,783
First Mortgage Bonds, Series 2014E-1, 3.70% due 2024	—	128,002
First Mortgage Bonds, Series 2014E-2, 4.70% due 2044	250,000	250,000
First Mortgage Bonds, Series 2010A, 6.00% due 2040	499,805	499,805
First Mortgage Obligations, Series 2014B, Tranche 1, 3.90%, due through 2033	180,000	180,000
First Mortgage Obligations, Series 2014B, Tranche 2, 4.30%, due through 2039	20,000	20,000
First Mortgage Obligations, Series 2014B, Tranche 3, 4.45%, due through 2045	550,000	550,000
Variable rate CFC, SOFR-based term loans, due through 2049	142,220	152,220
Variable rate CoBank, ACB, SOFR-based term loans, due through 2044	251,308	273,925
Syndicated variable rate, SOFR-based term, loan due 2025	—	150,000
Variable rate Wells Fargo, NA, SOFR-based term, loan due 2027	200,000	—
Pollution control revenue bonds		
Moffat County, CO, 2.90% term rate through October 2027, Series 2009, due 2036	46,800	46,800
Springerville certificates and other debt		
Series B, 7.14%, due through 2033	167,873	200,503
New Horizon Mine remaining land installment payments	400	500
Total long-term debt	**2,961,992**	**3,137,534**
Less debt issuance costs	(17,690)	(19,723)
Less debt discounts	(8,380)	(8,678)
Plus debt premiums	10,082	10,896
Total debt adjusted for discounts, premiums and debt issuance costs	**2,946,004**	**3,120,029**
Less current maturities	(88,658)	(223,523)
Long-term debt	**$ 2,857,346**	**$ 2,896,506**

Annual maturities of total long-term debt adjusted for debt issuance costs, discounts and premiums as of December 31, 2024 are as follows (dollars in thousands):

2025	$	88,758
2026		90,379
2027 (1)		292,270
2028		99,241
2029		74,753
Thereafter		2,300,603
	$	**2,946,004**

(1) Includes $200 million maturity for the Wells Fargo bilateral, 2024 note.

NOTE 7 – SHORT-TERM BORROWINGS

We have a commercial paper program under which we issue unsecured commercial paper in aggregate amounts not exceeding the commercial paper back-up sublimit under our 2022 Revolving Credit Agreement, which is the lesser of $500 million or the amount available under our 2022 Revolving Credit Agreement. The commercial paper issuances are used to provide an additional financing source for our short-term liquidity needs. The maturities of the commercial paper issuances vary but may not exceed 397 days from the date of issue. The commercial paper notes are classified as current and are included in current liabilities as short-term borrowings on our consolidated statements of financial position.

Commercial paper consisted of the following (dollars in thousands):

	2024		2023	
Commercial paper outstanding, net of discounts	$	—	$	184,205
Short-term borrowings - other	$	100	$	100
Weighted average interest rate		— %		5.62 %

As of December 31, 2024, $500 million of the commercial paper back-up sublimit remained available under the 2022 Revolving Credit Agreement. See Note 6 - Long-Term Debt.

NOTE 8 – FAIR VALUE

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market, or in the most advantageous market when no principal market exists. The fair value measurements accounting guidance emphasizes that fair value is a market-based measurement, not an entity-specific measurement. Therefore, a fair value measurement should be determined based on the assumptions that market participants would use in pricing the asset or liability (market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress). In considering market participant assumptions in fair value measurements, a three-tier fair value hierarchy for measuring fair value was established which prioritizes the inputs used in measuring fair value as follows:

Level 1 inputs are based upon quoted prices for identical instruments traded in active (exchange-traded) markets. Valuations are obtained from readily available pricing sources for market transactions (observable market data) involving identical assets or liabilities.

Level 2 inputs are based upon quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active and model-based valuation techniques (such as option pricing models and discounted cash flow models), for which all significant assumptions are observable in the market.

Level 3 inputs consist of unobservable market data which is typically based on an entity's own assumptions of what a market participant would use in pricing an asset or liability as there is little, if any, related market activity.

In instances where the determination of the fair value measurement is based on inputs from different levels of the fair value hierarchy, the level in the fair value hierarchy within which the entire fair value measurement falls is based on the lowest level input that is significant to the fair value measurement in its entirety. The assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability.

Executive Benefit Restoration Plan Trust

We have an irrevocable trust with an independent third party to fund the NRECA Executive Benefit Restoration Plan. The trust is funded quarterly to the prior year obligation as determined by the NRECA actuary. The trust consists of investments in equity and debt securities and are measured at fair value on a recurring basis. Changes in the fair value of investments in equity securities are recognized in earnings, and changes in fair value of investments in debt securities classified as available-for-sale are recognized in other comprehensive income until realized. The estimated fair value of the investments is based upon their active market value (Level 1 inputs) and is included in other noncurrent assets on our consolidated statements of financial position. The cost and fair values of our investments in the Executive Benefit Restoration Plan trust are as follows (dollars in thousands):

	December 31, 2024		December 31, 2023	
	Cost	Estimated Fair Value	Cost	Estimated Fair Value
Marketable securities	$ 10,101	$ 9,829	$ 10,821	$ 10,298

Marketable Securities

We hold marketable securities in connection with the directors' and executives' elective deferred compensation plans which consist of investments in stock funds, bond funds and money market funds. These securities are measured at fair value on a recurring basis with changes in fair value recognized in earnings. The estimated fair value of the investments is based upon their active market value (Level 1 inputs) and is included in other noncurrent assets on our consolidated statements of financial position. The amortized cost and fair values of our marketable securities are as follows (dollars in thousands):

	December 31, 2024		December 31, 2023	
	Cost	Estimated Fair Value	Cost	Estimated Fair Value
Marketable securities	$ 582	$ 587	$ 576	$ 530

Cash Equivalents

We invest portions of our cash and cash equivalents in commercial paper, money market funds, and other highly liquid investments. The fair value of these investments approximates our cost basis in the investments. In aggregate, the fair value was $182.0 million and $83.0 million as of December 31, 2024 and 2023, respectively.

Asset Retirement and Environmental Remediation Obligations

Accounting for asset retirement and environmental remediation obligations requires legal obligations associated with the retirement of long-lived assets to be recognized at fair value when incurred and capitalized as part of the related long-lived asset. In the absence of quoted market prices, we estimate the fair value of our asset retirement obligations using present value techniques, in which estimates of future cash flows associated with retirement activities are discounted using a credit-adjusted risk-free rate. Estimating the amount and timing of future expenditures includes, among other things, making projections of when assets will be retired and ultimately decommissioned, the amount of decommissioning costs, and how costs will escalate with inflation. In aggregate, the fair value of our newly recognized asset retirement and environmental remediation obligations were $38.3 million as of December 31, 2024.

Debt

The fair values of debt were estimated using discounted cash flow analyses based on our current incremental borrowing rates for similar types of borrowing arrangements. These valuation assumptions utilize observable inputs based on market data obtained from independent sources and are therefore considered Level 2 inputs (quoted prices for similar assets, liabilities (adjusted) and market corroborated inputs). The principal amounts and fair values of our debt are as follows (dollars in thousands):

	December 31, 2024		December 31, 2023	
	Principal Amount	Estimated Fair Value	Principal Amount	Estimated Fair Value
Total long-term debt	$ 2,961,992	$ 2,726,184	$ 3,137,534	$ 2,909,301

NOTE 9 – INCOME TAXES

We had $5.3 million of current income tax expense in 2024 and no current income tax in 2023. We had no deferred income tax expense in 2024 and deferred income tax expense of $4 thousand in 2023.

We utilize the liability method of accounting for income taxes, which requires that deferred tax assets and liabilities be determined based on the expected future income tax consequences of events that have been recognized in the consolidated financial statements. In accordance with our regulatory accounting treatment, changes in deferred tax assets or liabilities result in the establishment of a regulatory asset or liability. A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be received or settled through future rate revenues. Under this regulatory accounting approach, the income tax expense (benefit) on our consolidated statements of operations includes only the current portion.

Components of our net deferred tax liability are as follows (dollars in thousands):

	December 31, 2024	December 31, 2023
Deferred tax assets		
Net operating loss carryforwards	$ 66,423	$ 192,591
Operating lease liabilities	84,311	94,862
Deferred revenues and membership withdrawal	103,913	4,812
Safe harbor lease receivables	9,449	9,379
Other	54,054	34,171
	318,150	**335,815**
Less valuation allowance	—	—
	318,150	**335,815**
Deferred tax liabilities		
Basis differences- property, plant and equipment and other	154,745	168,948
Operating lease right-of-use assets	115,635	121,125
Capital credits from other associations	36,714	35,638
Deferred debt prepayment transaction costs	23,273	25,327
Other	—	—
	330,367	**351,038**
Net deferred tax liability	**$ (12,217)**	**$ (15,223)**

Net deferred tax liabilities decreased by $3.0 million in 2024 which is deferred and reflected as a decrease in the regulatory asset established for deferred income tax expense. The accounting for regulatory assets is discussed further in Note 2—Accounting for Rate Regulation. The regulatory asset balance associated with deferred income tax expense under the liability method is $12.2 million and $15.2 million as of December 31, 2024 and 2023, respectively.

The reconciliation between the statutory federal income tax rate and the effective tax rate is as follows (dollars in thousands):

	2024	2023	2022
Pretax GAAP income at Federal statutory rate	5,484	2,118	—
Pretax GAAP income at State statutory rate, net of federal benefit	731	282	—
Patronage exclusion	(6,215)	(2,401)	—
Asset retirement and environmental remediation obligations	9,934	(6,302)	16,655
Deferred revenues and membership withdrawal	99,101	(11,216)	(22,759)
Operating liabilities, net of right-of-use assets (1)	(4,989)	(5,281)	(4,919)
Prepaid lease	4,288	4,412	3,874
Depreciation, depletion and asset sales	10,659	(9,624)	(15,510)
Regulatory asset amortization	5,641	5,692	8,604
Provision for rate refund	1,667	41	12
Safe harbor lease	(1,774)	(1,939)	(3,847)
Goodwill	7,869	246	492
Valuation Allowance	—	—	—
Net operating loss carryforward	(121,624)	26,955	21,034
Other items, net	(3,950)	(3,518)	(3,070)
Impairment	—	—	—
Regulatory treatment of deferred taxes	(1,502)	539	(815)
Total deferred income tax expense (benefit)	**$ 5,320**	**$ 4**	**$ (249)**

(1) Net deferred tax liability established as a result of adopting ASC 842. See Note 11 - Leases.

We had an estimated tax income of $22.4 million after net operating loss utilization for 2024. We utilized an estimated $533.9 million of federal net operating losses during 2024. This includes the remaining balance of $444.5 million of pre-2018 net operating losses that offset taxable income with no limitation and $89.4 million of post-2018 net operating losses that are limited to offset 80 percent of taxable income. As of December 31, 2024, we have an estimated consolidated federal net operating loss carryforward of $290.1 million of which all are post-2018 net operating losses limited to offset 80 percent of taxable income with no expiration date. After utilization of an estimated $381.5 million state net operating losses, we have a remaining balance of $214.0 million of state net operating loss carryforwards subject to expiration in periods between 2041 and 2043. We did not establish a valuation allowance because it is more likely than not that the benefit from the federal and state net operating losses will be realized in the future.

We file a U.S. federal consolidated income tax return and income tax returns in state jurisdictions where required. The statute of limitations remains open for federal and state returns for the years 2019 forward. We do not have any reserves recorded for uncertain tax positions.

NOTE 10 - REVENUE

Revenue from contracts with customers

Our revenues are derived primarily from the sale of wholesale electric service to our Utility Members pursuant to long-term wholesale electric service contracts. Our contracts with our Utility Members extend through 2050.

Member electric sales

Revenues from wholesale electric power sales to our Utility Members are primarily from our Class A wholesale rate schedule filed with FERC. Our Class A rate schedule (A-40) was a stated rate and accepted by FERC on March 20, 2020. Our A-40 rate for electric power sales to our Utility Members remained in effect until July 31, 2024 and consisted of three billing components: an energy rate and two demand rates.

Our Class A rate schedule (A-41) for electric power sales to our Utility Members was accepted by FERC, effective August 1, 2024, subject to refund, and incorporated a new formulary rate, which can be adjusted annually based on the budged approved by our Board, including an annual true-up mechanism. Our A-41 rate consists of eleven rate components, with three energy-based and eight demand-based. Our budget used to set our Utility Members' formula rate is set by our Board.

Energy and demand have the same pattern of transfer to our Utility Members and are both measurements of the electric power provided to our Utility Members. Therefore, the provision of electric power to our Utility Members is one performance obligation. Prior to our Utility Members’ requirement for electric power, we do not have a contractual right to consideration as we are not obligated to provide electric power until the Utility Member requires each incremental unit of electric power. We transfer control of the electric power to our Utility Members over time and our Utility Members simultaneously receive and consume the benefits of the electric power. Progress toward completion of our performance obligation is measured using the output method: meter readings are taken at the end of each month for billing purposes, energy and demand are determined after the meter readings and Utility Members are invoiced based on the meter reading. Payments from our Utility Members are received in accordance with the wholesale electric service contracts’ terms, which is less than 30 days from the invoice date. Utility Member electric sales revenue is recorded as Utility Member electric sales on our consolidated statements of operations and accounts receivable – Members on our consolidated statements of financial position.

Revenue from one Utility Member, Poudre Valley Rural Electric Association, was $114.1 million, or 10.3 percent, of our Utility Member revenue and 7.0 percent of our total operating revenues in 2024. No other Utility Member exceeded 10 percent of our Utility Member revenue or our total operating revenues in 2024.

In addition to our Utility Member electric sales, we have non-member electric sales and other operating revenue which consist of several revenue streams. The following revenue is reflected on our consolidated statements of operations as follows (dollars in thousands):

	2024	2023	2022
Non-member electric sales:			
Long-term contracts	$ 120,579	$ 43,087	$ 56,570
Short-term contracts	75,982	102,141	106,785
Rate stabilization	211,232	47,127	95,613
Provision for rate refunds	(6,556)	94	(51)
Coal sales	10,091	13,257	7,021
Other	95,361	53,358	54,399
Total non-member electric sales and other operating revenue	**$ 506,689**	**$ 259,064**	**$ 320,337**

Non-member electric sales

Revenues from wholesale electric power sales to non-members are primarily from long-term contracts and short-term market sales. Prior to our customers’ demand for energy, we do not have a contractual right to consideration as we are not obligated to provide energy until the customer demands each incremental unit of energy. We transfer control of the energy to our customer over time and our customer simultaneously receives and consumes the benefits of the electric power. Progress toward completion of our performance obligation is measured using the output method. Payments are received in accordance with the contract terms, which is less than 30 days after the invoice is received by the customer.

Revenue from three non-members, WAPA, Salt River Project, and United Power, was $41.7 million, $39.3 million and $32.8 million, respectively, or 21.2 percent, 20.0 percent and 16.7 percent, respectively, of non-member electric sales and 2.6 percent, 2.4 percent and 2.0 percent, respectively, of our total operating revenues in 2024. No other non-member exceeded 10 percent of our total non-member electric sales or our total operating revenues in 2024.

Rate stabilization revenue

Rate stabilization represents recognition of income from withdrawal of former Utility Members from membership in us or non-member electric sales revenue that was previously deferred in accordance with accounting requirements related to regulated operations. We recognized $211.2 million of deferred membership withdrawal income for the year ended December 31, 2024, $47.1 million of deferred membership withdrawal income for the year ended December 31, 2023 and $95.6 million of deferred non-member electric sales revenue and deferred membership withdrawal income for the year ended December 31, 2022, as directed by our Board. The 2024 deferred membership withdrawal income includes recognition of $68.2 million of deferred membership withdrawal income in September 2024 to offset the expense recognition related to the write-off of the J.M. Shafer Generating Station and Colowyo Coal acquisition costs/goodwill. Additionally, we recognized $32.8 million of deferred membership withdrawal income from September 2024 to December 2024 to offset the expense recognition for accelerated expenses related to the transition from mining to full reclamation at the Colowyo Mine later in 2025, $39.1 million of deferred membership withdrawal income in December 2024 to offset the expense recognition related to the recording of environmental remediation obligations at New Horizon Mine and Colowyo Mine and $71.1 million of deferred membership withdrawal income during 2024 related to rate stabilization measures in order to meet our financial ratios and goals. See Note 2 - Accounting for Rate Regulation.

Provision for Rate Refunds

In December 2024, we reported to FERC, refunded to affected customers and recorded a refund in the amount of $4.7 million, including interest, for additional refunds related to certain power sold at market-based rates in the Western Area Colorado Missouri balancing authority area to non-members during a period in 2022 when FERC revoked our market-based rate authorization. Additionally, we recorded a provision for rate refund in the amount of $2.5 million related to the FERC's December 2024 compliance filing order on our Rate Schedule 281 (contract termination payment methodology) that addressed the calculation of a transmission credit for withdrawing Utility Members in the Western Interconnection and our February 2025 revised Rate Schedule 281 filed with FERC. FERC has not issued an order on our February 2025 revised Rate Schedule 281 and our refund calculation is subject to increase based upon our February 2025 revised Rate Schedule 281. See Note 14 - Commitments and Contingencies - Legal - CTP Proceeding.

Coal Sales

Coal sales revenue results from the sale of coal from the Colowyo Mine to third parties. We have an obligation to deliver coal and progress of completion toward our performance obligation is measured using the output method. Our performance obligation is completed as coal is delivered.

Other operating revenue

Other operating revenue consists primarily of wheeling, transmission and lease revenue. Other operating revenue also includes revenue we receive from our Non-Utility Members. Wheeling revenue is received when we charge other energy companies for transmitting electricity over our transmission lines (payments are received in accordance with the contract terms, which is within 20 days of the date the invoice is received). Transmission revenue is from Southwest Power Pool's scheduling of transmission across our transmission assets in the Eastern Interconnection because of our membership in it (Southwest Power Pool collects the revenue from the customer and pays us for the scheduling, system control, dispatch transmission service, and the annual transmission revenue requirement). Each of these services or goods are provided over time and progress toward completion of our performance obligations are measured using the output method. Lease revenue is from lease agreements where we are the lessor for certain operational assets with third parties including a tolling agreement with a third party at our Knutson Generating Station. See Note 11 - Leases.

NOTE 11 – LEASES

Leasing Arrangements as Lessee

We have lease agreements as lessee for the right to use various facilities and operational assets. Rent expense for all short-term and long-term operating leases was $1.9 million in 2024 and $2.4 million in 2023. Rent expense is included in various categories of operating expenses on our consolidated statements of operations based on the type and purpose of the lease. Right-of-use assets are included in deferred charges, the current portion of lease liabilities is included in accrued expenses and the long-term portion of lease liabilities is included in other deferred credits and other liabilities on our consolidated statements of financial position.

Our consolidated statements of financial position include the following lease components (dollars in thousands):

	December 31, 2024	December 31, 2023
Operating leases:		
Operating lease right-of-use assets	$ 13,221	$ 9,072
Less: Accumulated amortization	(3,110)	(2,595)
Net operating lease right-of-use assets	**$ 10,111**	**$ 6,477**
Operating lease liabilities – current	$ (332)	$ (371)
Operating lease liabilities – noncurrent	(5,703)	(1,396)
Total operating lease liabilities	**$ (6,035)**	**$ (1,767)**
Finance leases:		
Finance lease right-of-use assets	$ 95	$ —
Less: Accumulated amortization	(29)	—
Net finance lease right-of-use assets	**$ 66**	**$ —**
Finance lease liabilities - current	$ (47)	$ —
Finance lease liabilities - noncurrent	(12)	—
Total finance lease liabilities	**$ (59)**	**$ —**
Lease Term and Discount Rate:		
Weighted-average remaining lease term (in years)		
Operating leases	32.8	7.0
Finance leases	1.5	0.0
Weighted-average discount rate		
Operating leases	6.93 %	4.68 %
Finance leases	6.99 %	— %

Future expected minimum lease commitments under operating leases are as follows (dollars in thousands):

	Operating Leases	Finance Leases	Total
Year 1	$ 977	$ 51	$ 1,028
Year 2	528	11	539
Year 3	537	—	537
Year 4	513	—	513
Year 5	391	—	391
Thereafter	12,239	—	12,239
Total lease payments	**$ 15,185**	**$ 62**	**$ 15,247**
Less imputed interest	(9,150)	(3)	(9,153)
Total	**$ 6,035**	**$ 59**	**$ 6,094**

Leasing Arrangements as Lessor

We have lease agreements as lessor for certain operational assets. The revenue from these lease agreements of $15.7 million in 2024 and $6.7 million in 2023 are included in other operating revenue on our consolidated statements of operations.

In May 2024, the conditions for the effectiveness of a tolling agreement with a third party were satisfied for our two 70 MW units at our Knutson Generating Station for all capacity and energy through the operation of both units. In September 2024, we entered into a tolling agreement with a third party for one of our two 70 MW units at our Limon Generating Station for all capacity and energy through the operation of that unit that will commence in January 2026. In December 2024, we entered into a tolling agreement with a third party for one of our four 40 MW units at our Pyramid Generating Station for all capacity and energy through the operation of that unit that will commence in January 2025. In substance these agreements were determined to be leases in accordance with the accounting standards for leases as the third party has the right to the economic benefits of the asset and controls the use of the asset by its contractual rights, including the ability to direct the timing of dispatch of energy.

The lease arrangement with the Springerville Partnership is not reflected in our lease right right-of-use asset or liability balances as the associated revenues and expenses are eliminated in consolidation. See Note 13 - Variable Interest Entities. However, as the noncontrolling interest associated with this lease arrangement generates book-tax differences, a deferred tax asset and liability have been recorded. See Note 9 - Income Taxes.

NOTE 12 – EMPLOYEE BENEFIT PLANS

DEFINED BENEFIT PLAN: Substantially all of our 1,092 employees participate in the National Rural Electric Cooperative Association Retirement Security Plan ("RS Plan") except for the 192 employees of Colowyo Coal and any non-bargaining employees hired May 1, 2021 or later and bargaining employees hired July 1, 2021 or later. The RS Plan is a defined benefit pension plan qualified under Section 401(a) and tax-exempt under Section 501(a) of the Internal Revenue Code. It is considered a multiemployer plan under the accounting standards for compensation - retirement benefits. The plan sponsor's Employer Identification Number is 53-116145 and the Plan Number is 333.

A unique characteristic of a multiemployer plan compared to a single employer plan is that all plan assets are available to pay benefits to any plan participant. Separate asset accounts are not maintained for participating employers. This means that assets contributed by one employer may be used to provide benefits to employees of other participating employers.

Our contributions to the RS Plan in each of the years 2024, 2023 and 2022 represented less than 5 percent of the total contributions made each year to the plan by all participating employers. We made contributions to the RS Plan of $20.2, $31.6 and $25.2 million in 2024, 2023 and 2022, respectively.

In December 2012, the National Rural Electric Cooperative Association ("NRECA") approved an option to allow participating cooperatives in the RS Plan to make a contribution prepayment and reduce future required contributions. The prepayment amount is a cooperative's share, as of January 1, 2013, of future contributions required to fund the RS Plan's unfunded value of benefits earned to date using RS Plan actuarial valuation assumptions. The prepayment amount is equal to approximately 2.5 times a cooperative's annual RS Plan required contribution as of January 1, 2013. After making the prepayment, the annual contribution was reduced by approximately 25 percent, retroactive to January 1, 2013. The reduced annual contribution is expected to continue for approximately 15 years. However, changes in interest rates, asset returns, other plan experiences different from expected, plan assumption changes and other factors may have an impact on future contributions and the 15-year period.

In May 2013, we elected to make a contribution prepayment of $71.2 million to the RS Plan. This contribution prepayment was determined to be a long-term prepayment and therefore recorded in deferred charges and amortized beginning January 1, 2013 over the 13-year period calculated by subtracting the average age of our workforce from our normal retirement age under the RS Plan.

Our contributions to the RS Plan include contributions for substantially all of the 174 bargaining unit employees that are made in accordance with collective bargaining agreements. We ceased to add new bargaining employees hired July 1, 2021 or later and non-bargaining employees hired May 1, 2021 or later to the RS Plan.

For the RS Plan, a "zone status" determination is not required, and therefore not determined, under the Pension Protection Act ("Act") of 2006. In addition, the accumulated benefit obligations and plan assets are not determined or allocated separately by individual employer. In total, the RS Plan was over 80 percent funded at both January 1, 2024 and January 1, 2023, based on the Act funding target and the Act actuarial value of assets on those dates.

Because the provisions of the Act do not apply to the RS Plan, funding improvement plans and surcharges are not applicable. Future contribution requirements are determined each year as part of the actuarial valuation of the plan and may change as a result of plan experience.

We participate in the NRECA Pension Restoration Plan and the NRECA Executive Benefit Restoration Plan, both of which are intended to provide a supplemental benefit to the defined benefit plan for an eligible group of highly compensated employees. Eligible employees include the Chief Executive Officer and any other employees that become eligible. All our executive employees with a hire date prior to May 1, 2021 participate in one of the following pension restoration plans: the NRECA Pension Restoration Plan or the NRECA Executive Benefit Restoration Plan. Eligibility is determined annually and is based on January 1 base salary that exceeds the limits of the defined benefit plan. Employees hired May 1, 2021 or later are not eligible for either plan.

The NRECA Executive Benefit Restoration Plan obligations are determined annually (during the first quarter of the subsequent year) by an NRECA actuary and are included in accumulated postretirement benefit and postemployment obligations on our consolidated statements of financial position as follows (dollars in thousands):

	2024	2023
Executive benefit restoration obligation at beginning of period	$ 10,158	$ 8,485
Service cost	444	323
Interest cost	521	441
Plan amendments - prior service cost	1,027	—
Curtailment	(384)	—
Benefit payments	(898)	—
Actuarial (gain) loss	(2,950)	909
Executive benefit restoration obligation at end of period	**$ 7,918**	**$ 10,158**
Fair value of plan assets at beginning of year	$ 10,298	$ 9,808
Employer contributions	—	—
Benefits paid	(899)	—
Actual return on plan assets	430	490
Fair value of plan assets at end of year	**$ 9,829**	**$ 10,298**
Net (asset) liability recognized	**$ (1,911)**	**$ (140)**

The service cost component of our net periodic benefit cost is included in operating expenses on our consolidated statements of operations. The components of net periodic benefit cost other than the service cost component are included in other income (expense) on our consolidated statements of operations. We have an irrevocable trust with an independent third party to fund the NRECA Executive Benefit Restoration Plan. The trust is funded quarterly to the prior year obligation as determined by the NRECA actuary.

In accordance with the accounting standard related to defined benefit pension plans, actuarial gains and losses are not recognized in income but are instead recorded in accumulated other income on our consolidated statements of financial position. If the unrecognized amount is in excess of 10 percent of the projected benefit obligation, amounts are reclassified out of accumulated other comprehensive income and included in net income as the excess is amortized over the average remaining service lives of the active plan participants. Unrecognized actuarial gains and losses have been determined per actuarial studies for the executive benefit restoration obligation.

The net unrecognized actuarial gains and losses related to the executive benefit restoration obligations are included in accumulated other comprehensive income as follows (dollars in thousands):

	2024	2023
Accumulated other comprehensive loss at beginning of period	$ (1,639)	$ (2,105)
Unrecognized prior service cost	(1,027)	—
Amortization of prior service cost into other income	340	1,156
Amortization of actuarial loss	169	219
Curtailment and settlement	21	—
Unrecognized actuarial gain (loss)	2,950	(909)
Accumulated other comprehensive loss at end of period	**$ 814**	**$ (1,639)**

DEFINED CONTRIBUTION PLANS: We offer one 401(k) plan to all our employees. We contribute 1 percent of employee base salary for all non-bargaining employees hired prior to May 1, 2021. All non-bargaining employees hired May 1, 2021 or later and all bargaining employees hired July 1, 2021 or later are eligible for a maximum employer contribution of 10 percent which includes an employer base contribution and an employer match up to IRS allowed annual maximum. We offer one 401(k) plan to all employees of Colowyo Coal at the Colowyo Mine. We contribute 7 percent of employee salary and match up to an additional 5 percent of employee contributions for employees hired prior to May 1, 2021 and provide a maximum employer contribution of 10 percent which includes an employer base contribution and an employer match for employees hired May 1, 2021 or later. All employees are eligible to contribute up to 75 percent of their salary on a pre-tax basis. Under all plans, total 401(k) contributions are not to exceed annual IRS limitations, which are set annually. Employees who have attained age 50 in a calendar year are eligible for the catch-up contribution with maximum contribution limits determined annually by the IRS. We made contributions to the plan of $5.7 million, $4.9 million, and $3.9 million in 2024, 2023, and 2022, respectively.

Effective January 1, 2022 we adopted a 409(a) non-qualified plan. Senior managers, vice presidents and executive officers hired prior to May 1, 2021 are eligible to participate and contribute to the plan, but are not eligible for any employer contribution. Executive officers hired on or after May 1, 2021 will be eligible to participate and contribute to the plan, and are eligible for the employer contribution. The employer contribution is effective once the eligible executive has reached the maximum allowed contribution and employer contribution and match in our base 401(k) plan and includes a maximum employer contribution of 10 percent, which includes an employer base contribution and an employer match. We made minimal contributions to the plan in 2023 and 2024.

POSTRETIREMENT BENEFITS OTHER THAN PENSIONS: We sponsor three medical plans for all non-bargaining unit employees under the age of 65. Two of the plans provide postretirement medical benefits to full-time non-bargaining unit employees and retirees who receive benefits under those plans, who have attained age 55, and who elect to participate. All three of these non-bargaining unit medical plans offer postemployment medical benefits to employees on long-term disability. The plans were unfunded as of December 31, 2024, are contributory (with retiree premium contributions equivalent to employee premiums, adjusted annually) and contain other cost-sharing features such as deductibles. As of June 30, 2021, the plans ceased to provide postretirement medical benefits for employees who retire after June 30, 2021.

The postretirement medical benefit and post-employment medical benefit obligations are determined annually (during the fourth quarter) by an independent actuary and are included in accumulated postretirement benefit and postemployment obligations on our consolidated statements of financial position as follows (dollars in thousands):

	2024	2023
Postretirement medical benefit obligation at beginning of period	$ 924	$ 2,092
Interest cost	31	58
Benefit payments (net of contributions by participants)	(317)	(469)
Actuarial gain	(129)	(757)
Postretirement medical benefit obligation at end of period	**$ 509**	**$ 924**
Postemployment medical benefit obligation at end of period	175	243
Total postretirement and postemployment medical obligations at end of period	**$ 684**	**$ 1,167**

The service cost component of our net periodic benefit cost is included in operating expenses on our consolidated statements of operations. The components of net periodic benefit cost other than the service cost component are included in other income (expense) on our consolidated statements of operations.

In accordance with the accounting standard related to postretirement benefits other than pensions, actuarial gains and losses are not recognized in income but are instead recorded in accumulated other comprehensive income on our consolidated statements of financial position. If the unrecognized amount is in excess of 10 percent of the projected benefit obligation, amounts are reclassified out of accumulated other comprehensive income and included in net income as the excess amount is amortized over the average remaining service lives of the active plan participants. Unrecognized actuarial gains and losses have been determined per actuarial studies for the postretirement medical benefit obligation.

The net unrecognized actuarial gains and losses related to the postretirement medical benefit obligation are included in accumulated other comprehensive income as follows (dollars in thousands):

	2024	2023
Amounts included in accumulated other comprehensive income at beginning of period	$ 1,114	$ 2,078
Amortization of prior service credit into other income	(786)	(1,637)
Amortization of actuarial gain into other income	(146)	(84)
Actuarial gain	128	757
Amounts included in accumulated other comprehensive income at end of period	**$ 310**	**$ 1,114**

The assumptions used in the 2024 actuarial study performed for our postretirement medical benefit obligation were as follows:

Weighted-average discount rate	4.76 %
Initial health care cost trend (2018)	7.00 %
Ultimate health care cost trend	4.50 %
Year that the rate reached the ultimate health care cost trend rate	2034
Expected return on plan assets (unfunded)	N/A
Average remaining service lives of active plan participants (years)	2.42

The following are the expected future benefits to be paid (net of contributions by participants) related to the postretirement medical benefit obligation during the next ten years (dollars in thousands):

2025	$ 211,036
2026	154,727
2027	87,282
2028	52,655
2029	26,758
2029 through 2033	19,274
	$ 551,732

NOTE 13 – VARIABLE INTEREST ENTITIES

The following is a description of our financial interests in variable interest entities that we consider significant. This includes an entity for which we are determined to be the primary beneficiary and therefore consolidate.

Consolidated Variable Interest Entity

Springerville Partnership: We own a 51 percent equity interest, including the 1 percent general partner equity interest, in the Springerville Partnership, which is the 100 percent owner of Springerville Unit 3 Holding LLC ("Owner Lessor"). The Owner Lessor is the owner of the Springerville Unit 3. We, as general partner of the Springerville Partnership, have the full, exclusive and complete right, power and discretion to operate, manage and control the affairs of the Springerville Partnership and take certain actions necessary to maintain the Springerville Partnership in good standing without the consent of the limited partners. Additionally, the Owner Lessor has historically not demonstrated an ability to finance its activities without additional financial support. The financial support is provided by our remittance of lease payments in order to permit the Owner Lessor, the holder of the Springerville Unit 3 assets, to pay the debt obligations and equity returns of the Springerville Partnership. We have the primary risk (expense) exposure in operating the Springerville Unit 3 assets and are responsible for 100 percent of the operation, maintenance and capital expenditures of Springerville Unit 3 and the decisions related to those expenditures including budgeting, financing and dispatch of power. Based on all these facts, it was determined that we are the primary beneficiary of the Owner Lessor. Therefore, the Springerville Partnership and Owner Lessor have been consolidated by us.

Assets and liabilities of the Springerville Partnership that are included in our consolidated statements of financial position are as follows (dollars in thousands):

	December 31, 2024	December 31, 2023
Net electric plant	$ 676,367	$ 703,859
Noncontrolling interest	130,498	134,269
Long-term debt	172,790	206,027
Accrued interest	4,997	5,968

Our consolidated statements of operations include the following Springerville Partnership expenses (dollars in thousands):

	2024	2023	2022
Depreciation, amortization and depletion	$ 27,492	$ 18,138	$ 18,138
Interest	11,581	13,859	17,064

The revenue and lease expense associated with the Springerville Partnership lease has been eliminated in consolidation. Income, losses and cash flows of the Springerville Partnership are allocated to the general and limited partners based on their equity ownership percentages. The net income or loss attributable to the 49 percent noncontrolling equity interest in the Springerville Partnership is reflected on our consolidated statements of operations.

NOTE 14 – COMMITMENTS AND CONTINGENCIES

COAL PURCHASE REQUIREMENTS: We are committed to purchase coal for our generating plants under contracts that expire between 2027 and 2041. These contracts require us to purchase a minimum quantity of coal at prices subject to escalation reflecting cost increases incurred by the suppliers due to market conditions. The coal purchase projection includes estimated future prices. As of December 31, 2024, the minimum coal to be purchased under these contracts is as follows (dollars in thousands):

2025	$ 42,935
2026	26,897
2027	23,866
2028	12,011
2029	12,189
Thereafter	65,073
	$ 182,971

Our coal purchases were $90.1 million in 2024, $119.7 million in 2023, and $124.0 million in 2022.

ELECTRIC POWER PURCHASE CONTRACTS: Our largest long-term electric power purchase contracts are with Basin and Western Area Power Administration ("WAPA"). We purchase from Basin power pursuant to two contracts: one relating to all the power which we require to serve our Utility Members' load in the Eastern Interconnection and one relating to fixed scheduled quantities of electric power in the Western Interconnection. Both contracts with Basin continue through December 31, 2050 and are subject to automatic extension thereafter.

We purchase renewable power under long-term contracts, including hydroelectric power from WAPA and from specified renewable generating facilities, including wind, solar and small hydro. We purchase from WAPA power pursuant to two contracts: (i) one contract relating to WAPA's Loveland Area Projects that commenced delivery on October 1, 2024 and terminates September 30, 2054, and (ii) one contract relating to WAPA's Salt Lake City Area Integrated Projects that commenced delivery on October 1, 2024 and terminates September 30, 2057.

As of December 31, 2024, we have entered into renewable power purchase contracts to purchase the entire output from specified renewable facilities totaling approximately 1,118 MWs, including 674 MWs of wind-based power purchase contracts and 425 MWs of solar-based power purchase contracts, that expire between 2030 and 2043.

Costs under the above electric power purchase contracts were as follows (dollars in thousands):

	2024	2023	2022
Basin	$ 148,074	$ 142,456	$ 148,146
WAPA	73,395	74,899	67,791
Renewables, other than WAPA	85,436	78,177	85,601

ENVIRONMENTAL: As with most electric utilities, we are subject to extensive federal, state and local environmental requirements that regulate, among other things, air emissions, water discharges and the use and management of hazardous and solid wastes. Compliance with these requirements requires significant expenditures for the installation, maintenance and operation of pollution control equipment, monitoring systems and other equipment or facilities.

Our operations are subject to environmental laws and regulations that are complex, change frequently and have generally become more stringent and numerous over time. Federal, state, and local standards and procedures that regulate environmental impact of our operations are subject to change. Consequently, there is no assurance that environmental regulations applicable to our facilities will not become materially more stringent, or that we will always be able to obtain all required operating permits. More stringent standards may require us to modify the design or operation of existing facilities or purchase emission allowances. An inability to comply with environmental standards could result in reduced operating levels or the complete shutdown of our facilities that are not in compliance, including the shutting down of additional generating facilities or the shutting down of individual coal-fired generating facilities earlier than scheduled. The cost impact of the implementation of regulation on existing legislation and future legislation or regulation will depend upon the specific requirements thereof and cannot be determined at this time, but it could have a significant effect on our financial condition, results of operations and cash flow.

From time to time, we are alleged to be in violation or in default under orders, statutes, rules, regulations, permits or compliance plans relating to the environment. Additionally, we may need to deal with notices of violation, enforcement proceedings or challenges to construction or operating permits. In addition, we may be involved in legal proceedings arising in the ordinary course of business. However, we believe our facilities are currently in compliance with such regulatory and operating permit requirements.

LEGAL:

CTP Proceeding: Pursuant to our Bylaws, a Member may only withdraw from membership in us upon compliance with such equitable terms and conditions as our Board may prescribe provided, however, that no Member shall be permitted to withdraw until it has met all its contractual obligations to us. On September 1, 2021, we filed with FERC a modified contract termination payment methodology tariff as Rate Schedule 281 that provides a process should a Utility Member elect to withdraw from membership in us and terminate its wholesale electric service contract. The tariff process includes requirements for a two-year notice and the payment to us of a contract termination payment. On October 29, 2021, FERC accepted our modified contract termination payment methodology, effective November 1, 2021, subject to refund. FERC set the matter for hearing and instituted a concurrent Federal Power Act ("FPA") section 206 proceeding to determine the justness and reasonableness of our modified methodology. On December 19, 2023, FERC issued an order adopting a modified balance sheet approach for the contract termination payment methodology ("FERC December 19 Order").

On April 29, 2022, both United Power and Northwest Rural Public Power District ("NRPPD") provided us non-conditional notices to withdraw from membership in us, with a May 1, 2024, withdrawal effective date. On January 25, 2023, Mountain Parks Electric, Inc. ("MPEI") provided us a non-conditional notice to withdraw from membership in us, with a February 1, 2025, withdrawal effective date.

On January 18, 2024, we, United Power, and others filed requests for rehearing with FERC of the FERC December 19 Order. Our request for rehearing included disputing FERC's rejection of our lost revenue approach and also certain clarifications. On February 20, 2024, FERC issued a notice stating the parties' requests for rehearing were denied by operation of law, but FERC stated it will address the merits of the requests in a subsequent order. On March 28, 2024, we filed a petition for review of the FERC December 19 Order with the United States Court of Appeals for the Tenth Circuit ("10th Circuit Court of Appeals"), Case No. 24-9516. On April 8, 2024, United Power filed a petition for review of the FERC December 19 Order. United Power, MPEI, NRPPD, Basin, and La Plata Electric Association, Inc. ("LPEA") have filed notices of interventions in our petition for review with the 10th Circuit Court of Appeals.

On May 23, 2024, FERC issued a substantive order on rehearing, which modified the discussion in, but sustained the results of, the FERC December 19 Order (“May 23 Order”). On May 31, 2024, we filed a petition for review of the May 23

Order, Case No. 24-9538, with the 10th Circuit Court of Appeals. On June 3, 2024, the 10th Circuit Court of Appeals issued an order partially consolidating the cases for purposes of briefing. We and United Power filed opening briefs with the 10th Circuit Court of Appeals on October 7, 2024. Basin filed its opening brief in support of us and certain other intervening petitioners filed their combined opening brief in support of United Power on October 28, 2024. FERC filed its brief on January 25, 2025. Briefing is expected to be completed in March 2025 and we expect the court to set oral arguments.

On January 25, 2024, we filed a revised Rate Schedule 281 with FERC with the contract termination methodology based upon the FERC December 19 Order. On March 29, 2024, FERC issued an order accepting our revised Rate Schedule 281, subject to further compliance filing, and established hearing and settlement judge procedures related to our sleeving administrative fee methodology set forth in our revised Rate Schedule 281. On April 12, 2024, we submitted a further revised Rate Schedule 281 as directed by FERC's March 2024 order. On June 28, 2024, we submitted a further revised Rate Schedule 281 as directed by FERC's May 23 Order. On December 5, 2024, FERC issued an order on our compliance filings accepting our April 2024 and June 2024 revisions of Rate Schedule 281, subject to further compliance filing ("FERC December 2024 Order"). The FERC December 2024 Order addressed the calculation of the contract termination payment for Utility Members served in the Eastern Interconnection and referred to a provision in our Amended and Restated Wholesale Power Contract for the Eastern Interconnection with Basin ("Basin Eastern WPC") to inform our calculation of such amount. The FERC December 2024 Order also addressed the calculation of a transmission credit for withdrawing Utility Members in the Western Interconnection. We, United Power, and others filed requests for rehearing with FERC of the FERC December 2024 Order that were denied by operation of law. Our fourth compliance filing based upon the FERC December 2024 Order was filed with FERC on February 5, 2025. On February 12, 2025, we filed a petition for review of the FERC December 2024 Order, Case No. 25-9522, with the 10th Circuit Court of Appeals.

NRPPD did not comply with Rate Schedule 281 on-file with FERC and made no contract termination payment to us arising out of its April 2022 notice of intent to withdraw. NRPPD’s wholesale electric service contract with us remains in effect and NRPPD remains a Class A member of us. In the FERC December 2024 Order, FERC confirmed NRPPD remains a Utility Member of us.

On May 1, 2024, United Power withdrew its membership in us and pursuant to Rate Schedule 281 on-file with FERC and a Membership Withdrawal Agreement terminated its wholesale electric service contract with us. United Power’s contract termination payment amount was $709.4 million. United Power paid us an exit fee in cash of $627.2 million, after a regulatory liabilities credit and relinquishing its right to any patronage capital in us resulting in a discounted patronage capital credit of $82.2 million. Such amounts remain subject to true-up in accordance with Rate Schedule 281 and United Power's Membership Withdrawal Agreement.

On February 1, 2025, MPEI withdrew its membership in us and pursuant to Rate Schedule 281 on-file with FERC and a Membership Withdrawal Agreement terminated its wholesale electric service contract with us. MPEI's contract termination payment amount was $86 million, including MPEI's pro rata share of our power purchase obligations in the Western Interconnection. MPEI paid us an exit fee in cash of $71.6 million and relinquished its right to any patronage capital in us resulting in a discounted patronage capital credit of $14.5 million. Such amounts remain subject to true-up in accordance with Rate Schedule 281 and MPEI's Membership Withdrawal Agreement.

As provided in the Membership Withdrawal Agreements with United Power and MPEI, United Power and MPEI's contract termination payments are also subject to true-up in the event Rate Schedule 281 and the amount paid are modified pursuant to a subsequent final and non-appealable FERC order, including resolution of the petitions for review.

It is not possible to predict the outcome of this matter or whether we will be required to refund any amounts to United Power or MPEI, if United Power or MPEI will be required to pay us any additional amounts, or if the portion of the contract termination payment allocated to the transmission credit will increase and the amount of such increase.

Energy Sales - Soft-Cap. In August 2020, we made certain energy sales to third parties in excess of the soft-cap price for short-term, spot market sales of $1,000 per megawatt hour established by the Western Electricity Coordinating Council. On October 7, 2020, we filed a report with FERC justifying the sales above the soft-cap and we did not recognize the revenue for the energy sales in excess of the soft-cap, EL21-65-000. Based upon additional guidance from FERC, we filed a supplemental report on July 19, 2021. On May 20, 2022, FERC issued an order directing us to refund only certain amounts of the energy sales revenue in excess of the soft-cap. Based upon the FERC order, in the second quarter of 2022, we recognized approximately $2.9 million in excess of the soft-cap and refunded $0.4 million to a third party. On July 22, 2022, the California Public Utilities Commission filed a petition for review with the United States Court of Appeals for the District of Columbia Circuit ("DC Circuit Court of Appeals") of FERC’s May 20, 2022 order, 22-1169. On August 18, 2022, we filed a motion to intervene with the DC Circuit Court of Appeals and an order granting said motion was issued on September 6, 2022. On January 24, 2023, the parties to the proceeding filed a motion with the court to consolidate this proceeding with other related proceedings with the DC Circuit Court of Appeals and proposed a procedural schedule with final briefings due in October 2023. On March 6, 2023, the DC Circuit Court of Appeals granted the motion to consolidate the proceedings. On July 9, 2024, the DC Circuit Court of Appeals issued an order vacating FERC's order and remanding the case back to FERC to conduct a *Mobile-Sierra* analysis. It is not possible to predict the outcome of this matter or whether we will be required to refund any additional amounts to third parties.

LPEA's La Plata County District Court Complaint. On November 10, 2023, LPEA filed a Complaint in the La Plata County District Court, 2023CV30148, against us. The complaint alleged, among other things, that we have breached our Bylaws and our wholesale electric service contract with LPEA by failing to provide equitable terms and conditions for LPEA to withdraw from us and by violating the implied covenant of good faith and fair dealing.

On November 1, 2024, we and LPEA executed a settlement Term Sheet that was approved by each party's Board. The parties agreed to a mutual release of claims, and to file a stipulation of dismissal, with prejudice, of the litigation pending in La Plata County District Court after the parties executed a formal settlement agreement. On January 24, 2025, the parties executed the formal settlement agreement and filed a joint dismissal of all claims with prejudice. The court issued an order dismissing the lawsuit on January 29, 2025.

NRPPD Complaint. On March 25, 2024, NRPPD filed an FPA section 206 proceeding with FERC, Docket No. EL24-93, against us and Basin seeking FERC to exercise primary jurisdiction over the interpretation of the FERC December 19 Order and Basin Eastern WPC. In particular, NRPPD requested that FERC hold that NRPPD's withdrawal from us is permissible under the Basin Eastern WPC and that NRPPD's contract termination payment calculation is the appropriate contract termination payment. On May 8, 2024, we and Basin separately filed answers to NRPPD's complaint. Both us and Basin requested FERC to deny NRPPD's complaint. On December 5, 2024, FERC issued an order denying NRPPD's complaint because NRPPD failed to satisfy its burden under FPA section 206. FERC also determined that NRPPD's withdrawal from us does not cause a breach of the Basin Eastern WPC. On January 3, 2025, Basin filed a request for rehearing with FERC of FERC's December 5 order related to FERC's interpretation of the Basin Eastern WPC that NRPPD's withdrawal from us is not a breach of the Basin Eastern WPC. On February 3, 2025, FERC issued a notice stating the request for hearing was denied by operation of law. On February 13, 2025, Basin filed a petition for review of FERC's December 5 order, Case No. 25-1060, with the DC Circuit Court of Appeals. On March 17, 2025, we filed a notice of intervention in Basin's petition for review in support of Basin.

NOTE 15 – SUBSEQUENT EVENTS

We evaluated subsequent events through March 19, 2025, which is the date when the financial statements were issued.

On February 1, 2025, MPEI withdrew from membership in us and terminated its wholesale electric service contract with us pursuant to Rate Schedule 281 on-file with FERC and a Membership Withdrawal Agreement with MPEI. MPEI's contract termination payment amount was $86 million, including MPEI's pro rata share of our power purchase obligations in the Western Interconnection. MPEI paid us an exit fee in cash of $71.6 million and relinquished its right to any patronage capital in us resulting in a discounted patronage capital credit of $14.5 million. See Note 14 - Commitments and Contingencies - Legal.

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

In October 2023, following an evaluation of audit fees and costs and at the recommendation of our Finance and Audit Committee and approval of our Board, we chose not to continue with the engagement of Ernst & Young LLP as our independent registered public accounting firm effective after the completion of their audit of our financial statements for the year ended December 31, 2023.

Ernst & Young LLP's reports on the our financial statements for the years ended December 31, 2023 and 2022 did not contain an adverse opinion or a disclaimer of opinion, and were not qualified or modified as to uncertainty, audit scope, or accounting principles.

During fiscal years ended December 31, 2023 and 2022, there were no disagreements, within the meaning of Item 304(a)(1)(iv) of Regulation S-K promulgated under the Exchange Act and the related instructions thereto, with Ernst & Young LLP on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, which disagreements, if not resolved to the satisfaction of Ernst & Young LLP, would have caused it to make reference to the subject matter of the disagreements in connection with its reports. Also during this same period, there were no reportable events within the meaning of Item 304(a)(1)(v) of Regulation S-K and the related instructions thereto, except for the material weakness in our internal control over financial reporting related to the accounting for asset retirement and environmental remediation obligations for coal mines, previously reported in Item 9A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2022.

In October 2023, our Finance and Audit Committee recommended and our Board approved the appointment of Deloitte & Touche LLP as our new independent registered public accounting firm for the audit of our financial statements for the year ended December 31, 2024 and related interim periods. During fiscal years ended December 31, 2023 and 2022, neither we nor anyone acting on its behalf consulted with Deloitte regarding any of the matters described in Items 304(a)(2)(i) and (ii) of Regulation S-K.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this annual report, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended. Based on this evaluation, our principal executive officer and principal financial officer concluded that as of December 31, 2024, our disclosure controls and procedures were effective, to provide reasonable assurance that information required to be disclosed in our reports under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms and that such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Management necessarily applies its judgment in assessing the costs and benefits of such controls and procedures that, by their nature, can only provide reasonable assurance regarding management's control objectives.

Management's Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Our 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 GAAP and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that our receipts and expenditures are being made only in accordance with authorizations of our management and Board; and
- provide reasonable assurance that unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements are prevented or detected timely.

Management, including our principal executive officer and principal financial officer, does not expect that our internal controls will prevent or detect all errors and all fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. In addition, any evaluation of the effectiveness of controls is subject to risks that those internal controls may become inadequate in future periods because of changes in business conditions, or that the degree of compliance with the policies or procedures deteriorates.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2024. In making this assessment, management used the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in 2013. Based on its evaluation, management has concluded that our internal control over financial reporting was effective as of December 31, 2024.

Changes in Internal Control over Financial Reporting

During the third quarter of 2024, we completed the migration and upgrade to a new hosted software solution for our accounting and supply chain management systems, along with other systems. The implementation and migration of the new software solution results in material changes to our internal controls over financial reporting. We have updated the internal controls as appropriate and will continue to monitor the impact of the new software solution on our financial reporting business processes. Other than related to the new software solution, there were no changes that occurred during the fourth quarter ended December 31, 2024 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not Applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Directors

Each Member elects one representative to serve on our Board, unless such Member waives or declines representation on our Board. Each Class A member and each Class B member that purchases at least 65 percent of capacity from us elects its representative to serve on our Board, unless such Member waives or declines representation on our Board. LPEA and our Non-Utility Members have either waived or declined representation on our Board. Each of our directors must be a general manager, director or trustee of such Member. Except as otherwise provided in our Bylaws, the term of each director is from the time he or she is elected by his or her Member, and such election is certified in writing to us by such Member until such Member elects another person to serve and the fact of such election is certified in writing to us by such Member. Each representative on our Board brings an understanding of our Utility Members' business and brings insight to our Utility Members' operations which we believe qualifies them to serve on our Board. The directors on our Board and their ages as of March 1, 2025 are as follows:

NAME	AGE	UTILITY MEMBER - REPRESENTATIVE
Timothy A. Rabon—Chairman and President	64	Otero County Electric Cooperative, Inc.
Donald Keairns—Vice Chairman	65	San Isabel Electric Association, Inc.
Julie Kilty—Secretary	66	Wyrulec Company
Stuart Morgan—Treasurer	78	Wheat Belt Public Power District
Thaine Michie—Assistant Secretary	84	Poudre Valley Rural Electric Association, Inc.
Scott Wolfe—Assistant Secretary	61	San Luis Valley Rural Electric Cooperative, Inc.
Charles Abel II—Executive Committee	56	Sangre de Cristo Electric Association, Inc.
Arthur W. Connell—Executive Committee	71	Central New Mexico Electric Cooperative, Inc.
Douglas Shawn Turner—Executive Committee	63	The Midwest Electric Cooperative Corporation
Leroy Anaya	68	Socorro Electric Cooperative, Inc.
Robert Baca	60	Mora-San Miguel Electric Cooperative, Inc.
Lucas Bear	44	Northwest Rural Public Power District
Robert Bledsoe	75	K.C. Electric Association
Lawrence Brase	78	Southeast Colorado Power Association
Leo Brekel	73	Highline Electric Association
William Bridges	64	Big Horn Rural Electric Company
Robert Brockman	75	Wheatland Rural Electric Association
Matt M. Brown	73	High Plains Power, Inc.
Kevin Cooney	69	San Miguel Power Association, Inc.
Elias Coriz	59	Jemez Mountains Electric Cooperative, Inc.
Joel Gilbert	66	Southwestern Electric Cooperative, Inc.
Rick Gordon	71	Mountain View Electric Association, Inc.
Ronald Hilkey	85	White River Electric Association, Inc.
Larry Hoozee	72	Morgan County Rural Electric Association
Joe Hoskins	70	Continental Divide Electric Cooperative, Inc.
Zane Shanon Nunn	54	Columbus Electric Cooperative, Inc.
Steve M. Rendon	70	Northern Rio Arriba Electric Cooperative, Inc.
Corey Robinson	35	Empire Electric Association, Inc.
Peggy A. Ruble	71	Garland Light & Power Company
Roger L. Schenk	61	Y-W Electric Association, Inc.
Gary Shaw	70	Springer Electric Cooperative, Inc.
Kevin Stuart	59	Chimney Rock Public Power District
Darryl Sullivan	74	Sierra Electric Cooperative, Inc.
Kevin Thomas	67	High West Energy, Inc.
Clay Thompson	66	Carbon Power & Light, Inc.

Wesley Ullrich	68	Roosevelt Public Power District
Morgan Weinberg	47	Gunnison County Electric Association
William Wilson	70	Niobrara Electric Association, Inc.
Phillip Zochol	49	Panhandle Rural Electric Membership Association

Timothy A. Rabon has served on our Board since April 2014 and has been Chairman and President of our Board since August 2021. Prior to serving as Chairman and President of our Board, he served as Vice-Chairman of our Board. He is a member of the Executive Committee, as well as Ex-officio of the Engineering and Operations Committee, the External Affairs-Member Relations Committee, and the Finance and Audit Committee. Mr. Rabon serves as a trustee of Otero County Electric Cooperative, Inc. He is President of Mesa Verde Enterprises, Inc., which is a heavy horizontal civil construction company. He is the Vice President of Heritage Group, which is a commercial and residential land development company. He is a partner of Mesa Verde Ranch LLP, which is a land holding and cow/calf ranching operation. He is President of Aggregate Technologies, LLC, which is a mining and aggregate production and trucking operation. He is owner of MV2, LLC, which is a land holding and construction and demolition landfill operation. He is Vice President and co-owner of Trabon LLC, which is a trucking and property management company. He is a managing partner of TR Bar LLC, which is a company that sells and services firearms and archery equipment.

Donald Keairns has served on our Board since April 2012 and has been Vice-Chairman of our Board since August 2021. He is a member of the Executive Committee and the Finance and Audit Committee. Mr. Keairns serves as a director of San Isabel Electric Association, Inc. He owned and managed several rental properties. Mr. Keairns also serves as a director of Western United Electric Supply Corporation.

Julie Kilty has served on our Board since January 2013 and is Secretary of our Board. She is a member of the Executive Committee and the Finance and Audit Committee. Ms. Kilty serves as Assistant Secretary of Wyrulec Company. She is owner of Bar X Ranch, LLC and partner of Bar X Design, LLC.

Stuart Morgan has served on our Board since May 2007 and is Treasurer of our Board. He is a member of the Executive Committee and the Finance and Audit Committee. Mr. Morgan serves as a director of Wheat Belt Public Power District. He is President and owner of Morgan Farms, Inc. in Dalton, Nebraska. Mr. Morgan also serves as director of Western States Power Corporation.

Thaine Michie has served on our Board since March 2009 and is Assistant Secretary of our Board. He is a member of the Executive Committee and the Engineering and Operations Committee. Mr. Michie serves as a director of Poudre Valley Rural Electric Association, Inc. He is a retired Chief Executive Officer of Platte River Power Authority.

Scott Wolfe has served on our Board since June 2008 and is Assistant Secretary of our Board. He is a member of the Executive Committee and the Engineering and Operations Committee. Mr. Wolfe serves as director of San Luis Valley Rural Electric Cooperative, Inc. He is a retired farmer and owns Lobo Farm LLC.

Charles Abel II has served on our Board since April 2019. He is a member of the Executive Committee and the Finance and Audit Committee. Mr. Abel serves as Treasurer of Sangre de Cristo Electric Association. He is self-employed as a CPA providing tax and financial services to individuals and small businesses. Mr. Abel also serves as a director of CFC.

Arthur W. Connell has served on our Board since July 2000. He is a member of the Executive Committee and the Engineering and Operations Committee. Mr. Connell serves as a trustee of Central New Mexico Electric Cooperative, Inc. and is a rancher.

Douglas Shawn Turner has served on our Board since April 2015. He is a member of the Executive Committee and the Chairman of the Engineering and Operations Committee. Mr. Turner serves as President of The Midwest Electric Cooperative Corporation. He is a farmer and rancher and the owner and operator of Turn-West Farms, Inc. and Wild Horse Spring Land & Cattle Co.

Leroy Anaya has served on our Board since May 2018. He is a member of the External Affairs-Member Relations Committee. Mr. Anaya serves as a trustee of Socorro Electric Cooperative, Inc. He is retired from the Socorro County Assessor's office.

Robert Baca has served on our Board since June 2016. He serves as Chairman of the External Affairs-Member Relations Committee. Mr. Baca serves as Chairman of Mora-San Miguel Electric Cooperative, Inc. He is a self-employed electrician and owner of EGB Electric.

Lucas Bear has served on our Board since January 2025. He is a member of the External Affairs-Member Relations Committee. Mr. Bear serves as a director of Northwest Rural Power District. Mr. Bear is owner and operator of a cow/calf operation.

Robert Bledsoe has served on our Board since July 1998. He is a member of the Finance and Audit Committee. Mr. Bledsoe serves as a director of K.C. Electric Association. He is a self-employed rancher and farmer, half owner of Bledsoe Livestock Co. LLC, and a partial owner of Bledsoe Wind, LLC. Mr. Bledsoe is also on the board of directors of Colorado Rural Electric Association.

Lawrence Brase has served on our Board since April 2018. He is a member of the Finance and Audit Committee. Mr. Brase serves as a director of Southeast Colorado Power Association. He is a retired owner and operator of an independent insurance agency.

Leo Brekel has served on our Board since March 2003. He is a member of the Finance and Audit Committee. Mr. Brekel serves as a director of Highline Electric Association. He is a wheat farmer near Fleming, Colorado. Mr. Brekel also serves as a director of Basin.

William Bridges has served on our Board since June 2020. He is a member of the Engineering and Operations Committee. Mr. Bridges serves as Vice President of Big Horn Rural Electric Company. Mr. Bridges is a civil engineer and owns a consulting firm in Wyoming.

Robert Brockman has served on our Board since March 2024. He is a member of the External Affairs-Member Relations Committee. Mr. Brockman serves as President of Wheatland Rural Electric Association. He is involved in the ownership and operation of a real estate company primarily dealing in farm, ranch, and recreational properties in Wyoming. Mr. Brockman previously served as a director of CFC.

Matt M. Brown has served on our Board since April 2010. He is a member of the Finance and Audit Committee. Mr. Brown serves as Treasurer of High Plains Power, Inc. He is a rancher in Thermopolis, Wyoming.

Kevin Cooney has served on our Board since June 2020. He is a member of the Engineering and Operations Committee. Mr. Cooney serves as a director of San Miguel Power Association Inc. Mr. Cooney is an engineer and is President of Buka Engineering, Inc.

Elias Coriz has served on our Board since August 2023. He is a member of the External Affairs-Member Relations Committee. Mr. Coriz serves as a trustee of Jemez Mountains Electric Cooperative, Inc. He is a security specialist at the Los Alamos National Laboratory in New Mexico and former county commissioner in Rio Arriba County.

Joel Gilbert has served on our Board since August 2018. He is a member of the Engineering and Operations Committee. Mr. Gilbert serves as President of Southwestern Electric Cooperative, Inc. He is a retired livestock inspector with N.M. Livestock Board. He is currently operating/managing his own ranch.

Rick Gordon has served on our Board since November 1994. He is a member of the Finance and Audit Committee. Mr. Gordon serves as a director of Mountain View Electric Association, Inc. Mr. Gordon owns and operates Gordon Insurance, an independent insurance agency with offices in Calhan, Flagler, Limon and Sterling, Colorado.

Ronald Hilkey has served on our Board since March 2014. He is a member of the Engineering and Operations Committee. Mr. Hilkey serves as a director of White River Electric Association, Inc. Mr. Hilkey is a retired law enforcement officer and the previous owner of Adams Lodge Outfitters.

Larry Hoozee has served on our Board since August 2023. He is a member of the External Affairs-Member Relations Committee. Mr. Hoozee serves as a director of Morgan County Rural Electric Association. He operates his family farm and ranch.

Joe Hoskins has served on our Board since April 2022. He is a member of the External Affairs-Member Relations Committee. Mr. Hoskins serves as a trustee of Continental Divide Electric Cooperative, Inc. He is a retired manager for Maynard Buckles.

Zane Shanon Nunn has served on our Board since August 2024. He is a member of the External Affairs-Member Relations Committee. Mr. Nunn serves as a trustee of Columbus Electric Cooperative, Inc. He owns and operates the Hidden Valley Ranch RV Resort located in southern New Mexico.

Steve M. Rendon has served on our Board since October 2017. He is a member of the Finance and Audit Committee. Mr. Rendon serves as President of Northern Rio Arriba Electric Cooperative, Inc. He is a retired teacher with the Chama Valley Schools.

Corey Robinson has served on our Board since July 2024. He is a member of the External Affairs-Member Relations Committee. Mr. Robinson serves as a director of Empire Electric Association Inc. Mr. Robinson is a freelance filmmaker and owns Corey Robinson Films LLC.

Peggy A. Ruble has served on our Board since April 2017. She is a member of the Engineering and Operations Committee. Ms. Ruble serves as Vice President of Garland Light & Power Company. She is a retired executive assistant to the Park County Board of County Commissioners in Cody, Wyoming.

Roger L. Schenk has served on our Board since April 2019. He serves as Chairman of the Finance and Audit Committee. Mr. Schenk serves as a director of Y–W Electric Association, Inc. He is owner and operator of a farm.

Gary Shaw has served on our Board since June 2019. He is a member of the Engineering and Operations Committee. Mr. Shaw serves as Secretary of Springer Electric Cooperative, Inc. He is President and owner of Chateau Hill Ranch Company and Chateau Hill Cattle Company.

Kevin Stuart has served on our Board since December 2024. He is a member of the External Affairs-Member Relations Committee. Mr. Stuart serves as President and Board Chairman of Chimney Rock Public Power District. He is a self-employed farmer and rancher of Stuart Land & Cattle.

Darryl Sullivan has served on our Board since December 2013. He is a member of the Engineering and Operations Committee. Mr. Sullivan serves as a trustee of Sierra Electric Cooperative, Inc. He is a farmer and rancher in Monticello, New Mexico. He is a hat maker. He is also a western store owner and owner of Concrete Ditch-Lazer Level.

Kevin Thomas has served on our Board since May 2022. He is a member of the Engineering and Operations Committee. Mr. Thomas serves as a director for High West Energy, Inc. He is a retired school administrator and currently serves as an interim high school principal.

Clay Thompson has served on our Board since July 2020. He is a member of the Engineering and Operations Committee. Mr. Thompson serves as a director for Carbon Power & Light, Inc. Mr. Thompson is retired from the USDA Natural Resources Conservation Service and the U.S. Navy Reserves. He owns and operates the family ranch in Laramie, Wyoming.

Wesley Ullrich has served on our Board since April 2023. He is a member of the External Affairs-Member Relations Committee. Mr. Ullrich serves as Secretary of Roosevelt Public Power District. He is a self-employed farmer.

Morgan Weinberg has served on our Board since March 2024. He is a member of the External Affairs-Member Relations Committee. Mr. Weinberg serves as a director of Gunnison County Electric Association. He is a former managing partner of a ski manufacturer called Romp Skis LLC and currently works as a business and manufacturing consultant.

William Wilson has served on our Board since October 2019. He is a member of the External Affairs-Member Relations Committee. Mr. Wilson serves as a director at Niobrara Electric Association, Inc. He is a self-employed cattle rancher and owner of Wilson Ranch.

Phillip Zochol has served on our Board since December 2013. He is a member of the Finance and Audit Committee. Mr. Zochol serves as Vice President of Panhandle Rural Electric Membership Association. He is the assistant manager at Zochol Feedlot LLC.

Audit Committee Financial Expert

We do not have an audit committee financial expert due to our cooperative governance structure and the fact that our Board consists of one representative from our Utility Members. Such representative must be a general manager, director or trustee of such member.

Executive Officers

The following table sets forth the names and positions of our executive officers and their ages as of March 1, 2025:

NAME	AGE	POSITION
Duane Highley	63	Chief Executive Officer
Elda de la Peña	60	Chief Administrative Officer/CHRO
Robert Frankmore	52	Chief of Staff
Christopher Pink	53	Senior Vice President, Operations
Reginal "Reg" Rudolph	56	Chief Energy Innovations Officer
Jerome "Jay" Sturhahn	52	Senior Vice President, General Counsel
Todd E. Telesz	53	Senior Vice President/Chief Financial Officer
Lisa Tiffin	56	Senior Vice President, Energy Management

Duane Highley is our Chief Executive Officer and has served in that position since April 2019. Mr. Highley previously served as President and CEO of Arkansas Electric Cooperative Corporation and Arkansas Electric Cooperatives, Inc. and has over 42 years of experience with electric cooperatives. He has a bachelor's and master's degree from Missouri University of Science and Technology and completed the Harvard Business School Advanced Management Program. Mr. Highley serves as the co-chair of the Electric Subsector Coordinating Council and is the recipient of the Keystone Policy Center's 2023 Leadership Award.

Elda de la Peña is our Chief Administrative Officer/CHRO and has served in that position since June 2022. Ms. de la Peña's title changed from Senior Vice President, People and Culture/Chief Human Resource Officer to her current title when she assumed additional responsibilities including management of information technology. Ms. de la Peña previously served as Senior Manager, Employee Services and has served in numerous human resources roles since joining Tri-State in 1997. She has a master's degree in language and interpersonal communication and is a SHRM Senior Certified Professional and an HRCI certified Senior Professional in Human Resources.

Robert Frankmore is our Chief of Staff and has served in that position since June 2022. Mr. Frankmore previously served as our Vice President, Strategy. Prior to joining Tri–State in 2014, he served as Senior Vice President at Hill & Knowlton Strategies. Mr. Frankmore has over 22 years of experience in the energy industry and over 27 years of experience in governmental relations, communications and public affairs. He has a Bachelor of Arts degree in political science from Colorado State University.

Christopher Pink is our Senior Vice President of Operations and has served in that position since April 2024. Mr. Pink previously served as our Vice President of Engineering and Construction and has served in numerous transmission planning and engineering roles since joining Tri-State in 2008. He holds a Master's in Engineering Systems and a Bachelor's in Electrical Engineering from the Colorado School of Mines. He has over 20 years of experience in the energy sector.

Reginal "Reg" Rudolph is our Chief Energy Innovations Officer and has served in that position since January 2022. Prior to joining Tri-State, Mr. Rudolph served as General Manager of our Utility Member, San Isabel Electric Association, Inc. for 15 years and has over 33 years of experience in the electric utility industry. Mr. Rudolph has a Master's of Business Administration degree from Colorado State University and a Bachelor of Business Administration degree from North Dakota State University.

Jerome "Jay" Sturhahn is our Senior Vice President, General Counsel and has served in that position since October 2022. Prior to joining Tri–State, Mr. Sturhahn practiced law in Denver, Colorado as a member at Sherman & Howard L.L.C., including representing us on litigation and regulatory matters. He has a Bachelor of Arts degree from Yale University and a Jurisprudence Doctor degree from the University of Michigan Law School. He has over 22 years of legal experience.

Todd E. Telesz is our Senior Vice President/Chief Financial Officer and has served in that position since January 2024. Mr. Telesz was previously the Chief Executive Officer and General Manager of Basin between 2021 and 2023. Mr. Telesz previously served as senior vice president of the Power, Energy, and Utilities Division of CoBank. Mr. Telesz holds a Bachelor of Science in Economics, with honors, from The Wharton School of the University of Pennsylvania, and serves on several not-for-profit boards of directors.

Lisa Tiffin is our Senior Vice President of Energy Management and has served in that position since April 2024. Ms. Tiffin previously served as our Vice President of Planning and Analytics and has served in numerous planning and load forecasting roles since first joining Tri-State in 2004. She has a Bachelor of Science degree from MacMurray College. She has over 30 years of experience in the electric utility industry.

Code of Ethics

We have a code of ethics policy that applies to our employees including our principal executive officer, principal financial officer and principal accounting officer. A copy of this policy is available on our website, www.tristate.coop.

Insider Trading Policy

We have adopted our Board Policy for Insider Trading that prohibits the purchase of our securities by our directors, officers, and employees. A copy of our Board Policy for Insider Trading is included in Exhibit 19.1 to this annual report on Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

General Philosophy

Our compensation and benefits program is designed to provide a total compensation package that is competitive within the electric cooperative industry and the geographic areas in which our employees live and work. Our goal is to attract and retain competent personnel and to encourage superior performance by recognition and reward for individual ability and performance.

Total Compensation Package. We compensate our Chief Executive Officer and other executive officers through use of a total rewards package that includes base salary and benefits. Our Chief Executive Officer's base salary is based upon performance and national salary data provided by various surveys, which include data from the labor market for positions with similar responsibilities.

Process. The Executive Committee of our Board recommends on an annual basis the compensation for our Chief Executive Officer to the entire Board and our Board approves such compensation. Our Board has delegated to our Chief Executive Officer the authority to establish and adjust compensation for all other employees. The compensation for all other employees, including executive officers, is determined by the Chief Executive Officer based upon performance and market-based salary data.

Base Salaries. As an electric cooperative, we do not have publicly traded stock and as a result do not have equity-based compensation programs. For this reason, substantially all of our monetary compensation to our executive officers is provided in the form of base salary. We provide our executive officers with a level of cash compensation in the form of base salary that is commensurate with the duties and responsibilities of their positions as well as job performance. These salaries are determined based on market data for positions with similar responsibilities.

Bonuses. As a general practice, we do not normally issue bonuses. However, on occasion, a discretionary cash bonus may be awarded by the Chief Executive Officer to the executive officers or other employees. Our Board has the authority to award a bonus to the Chief Executive Officer if deemed appropriate.

Retention Agreements. The Chief Executive Officer, with the approval of our Board, has in the past executed retention agreements for certain executive officers and other staff as deemed appropriate from time to time. We currently have no retention agreements with our executive officers.

Severance Agreements. As a general practice, we normally do not provide severance packages to employees. However, on occasion, as part of hiring a new employee, we may provide a severance package.

Retirement Plans

Defined Benefit Plan. We participate in the RS Plan, a noncontributory, defined benefit, multiemployer master pension plan which is available to all of our non-bargaining employees hired prior to May 1, 2021 and all bargaining employees hired prior to July 1, 2021. This plan is a qualified pension plan under IRC Section 401(a). Benefits, which accrue under the plan, are based upon the employee's annual base salary as of November 15 of the previous year, their years of benefit service and the plan multiplier.

401(k) Plans. We offer one 401(k) plan to all of our employees. We contribute 1 percent of employee base salary for all non-bargaining employees hired prior to May 1, 2021. All non-bargaining employees hired May 1, 2021 or later and all bargaining employees hired July 1, 2021 or later are eligible for a maximum employer contribution of 10 percent which includes an employer base contribution and an employer match up to IRS allowed annual maximum.

We offer one 401(k) plan to all employees of Colowyo Coal at the Colowyo Mine. We contribute 7 percent of employee salary and match up to an additional 5 percent of employee contributions for employees hired prior to May 1, 2021 and provide a maximum employer contribution of 10 percent which includes an employer base contribution and an employer match for employees hired May 1, 2021 or later.

All employees are eligible to contribute up to 75 percent of their salary on a pre-tax basis. Under all plans, total 401(k) contributions are not to exceed annual IRS limitations which are set annually. Employees who have attained age 50 in a calendar year are eligible for the catch-up contribution with maximum contribution limits determined annually by the IRS.

NRECA Pension Restoration Plan and Executive Benefit Restoration Plan. We participate in the NRECA Pension Restoration Plan and the NRECA Executive Benefit Restoration Plan, both of which are intended to provide a supplemental benefit to the defined benefit plan for an eligible group of highly compensated employees with a hire date prior to May 1, 2021. Eligible employees include the Chief Executive Officer and any other employees that become eligible. All our executive employees with a hire date prior to May 1, 2021 participate in either the NRECA Pension Restoration Plan or the NRECA Executive Benefit Restoration Plan. Eligibility is determined annually and is based on January 1 base salary that exceeds the limits of the RS Plan. The funds for the NRECA Executive Benefit Restoration Plan are held in trust by a third-party bank, and the funds are subject to claims by our creditors in the event of insolvency. Employees hired May 1, 2021 or later are not eligible for either plan.

Executive Deferred Compensation Plan. We offer a non-qualified executive deferred compensation plan for an eligible group of highly compensated employees, which includes all executive employees. Eligible employees can contribute up to 30 percent of their salary on a pre-tax basis. Executive employees hired May 1, 2021 or later who are not eligible for the RS Plan, the NRECA Pension Restoration Plan or the NRECA Executive Benefit Restoration Plan are eligible for a 10 percent contribution from us to the executive deferred compensation plan.

Perquisites and Other Benefits

The Chief Executive Officer and the other executive officers receive the same health and welfare benefit plans and sick time as all employees. In addition to these benefits, they also receive the following:

- Company vehicle or monthly auto allowance: the Chief Executive Officer and other executive officers are provided their choice of a company vehicle for both business and personal use or a monthly stipend as an auto allowance. There are no restrictions on usage for company vehicles. If a company vehicle is provided, these vehicles are considered compensation, which is grossed up for income taxes. If an executive elects the monthly auto allowance, it is paid monthly and grossed up for income taxes.

- Vacation: Executive officers currently accrue vacation at the rate of six weeks per year. They may accrue up to a maximum of 1,040 hours of vacation.

Compensation Committee Report

The Executive Committee serves as the compensation committee of our Board and has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management and, based on such review and discussion, has recommended to our Board its inclusion in this annual report on Form 10-K.

Executive Committee Members:

Timothy A. Rabon
Donald Keairns
Julie Kilty
Stuart Morgan
Thaine Michie
Scott Wolfe
Charles Abel II
Arthur W. Connell
Douglas Shawn Turner

Compensation Committee Interlocks and Insider Participation

As described above, the Executive Committee of our Board recommends the compensation for our Chief Executive Officer to the entire Board and our Board approves the compensation. Our Board has delegated to our Chief Executive Officer the authority to establish and adjust compensation for all other employees other than himself. Timothy A. Rabon, Donald Keairns, Julie Kilty, Stuart Morgan, Thaine Michie, Scott Wolfe, Charles Abel II, Arthur W. Connell, and Douglas Shawn Turner serve as members of the Executive Committee.

Other than as noted below, no member of the Executive Committee is, or previously was, an officer or employee of us. Mr. Rabon is our Chairman and President, Mr. Keairns is our Vice Chairman, Ms. Kilty is our Secretary, Mr. Morgan is our Treasurer, Mr. Michie is our Assistant Secretary, and Mr. Wolfe is our Assistant Secretary. All of the members of our Executive Committee are directors of our Utility Members. Each of our Utility Members has a wholesale electric service contract with us and we received revenue from each of our Utility Members in excess of $120,000 in 2024.

Executive Compensation

Summary Compensation Table

The following table sets forth information concerning compensation awarded to, earned by or paid to our principal executive officer, principal financial officer and our three other most highly paid executive officers (based on total compensation for 2024). The table also identifies the principal capacity in which each of these executives serves or served.

Name and Title	Year	Salary	Change in pension value and nonqualified deferred compensation	Bonus	All other compensation (2)	Total
Duane D. Highley	2024	$ 1,666,968	$ 0 (1)	$ —	$ 75,002	$ 1,741,970
Chief Executive Officer	2023	1,555,645	0 (1)	—	60,393	1,616,038
	2022	1,489,353	1,822,524	—	65,565	3,377,442
Todd E. Telesz (3)	2024	542,502	25,501	140,350	105,216	813,569
Senior VP/CFO						
Patrick L. Bridges (4)	2024	258,141 (5)	146,324 (6)	—	1,148,965 (7)	1,553,430
Former Senior VP/CFO	2023	559,268	66,384	—	65,623	691,275
	2022	527,763	168,151	—	63,116	759,030
Jerome Sturhahn (8)	2024	726,871	40,632	70,176	107,196	944,875
Senior VP, General	2023	724,019	39,243	—	108,217	871,479
Counsel	2022	139,423	6,417	—	12,468	158,308
Elda M. de la Peña	2024	513,155	565,524	70,176	52,496	1,201,351
Chief Administrative	2023	465,378	0 (9)	—	47,812	513,190
Officer/CHRO	2022	413,773	450,394	—	51,698	915,865
Robert J. Frankmore	2024	442,711	121,127	70,176	61,656	695,670
Chief of Staff	2023	378,456	0 (9)	—	55,682	434,138
	2022	318,588	98,969	—	42,943	460,500

(1) For our Chief Executive Officer, the lump sum value of the RS Plan decreased by $317,547 from 2022 to 2023. Duane Highley quasi-retired on January 8, 2024 from the RS Plan, at which time the benefit calculation started over on January 9, 2024. Therefore, the change in value of the plan from December 31, 2024 to December 31, 2023 was a negative $2,759,177.

(2) Includes retention agreement payments, if applicable, monthly auto allowance or personal use of auto which is grossed up to cover taxes, relocation benefits, employer 401(k) and non-qualified executive plan contribution, pension restoration plan payout, if applicable, group term life, and employer paid premium for medical and dental.

(3) Effective January 29, 2024, Todd Telesz became an employee and our Senior Vice President, Chief Financial Officer at which time Patrick Bridges became Special Advisor to us. Mr. Telesz is not eligible for the RS Plan. He is eligible for the executive non-qualified deferred compensation plan.

(4) Mr. Bridges retired on March 8, 2024.

(5) Includes lump sum payout of vacation at time of retirement.

(6) Excludes any payments made under the RS Plan and Pension Restoration Plan. These payments are identified in the Defined Benefit Plan table below.

(7) Includes lump sum payout of pension restoration plan benefit at time of retirement, along with intent to retire payment and retirement recognition gift which is grossed up for years of service, both of which programs are available to all non-bargaining employees.

(8) Mr. Sturhahn became an employee and our General Counsel on October 17, 2022, and is not eligible for the RS Plan. He is eligible for the executive non-qualified deferred compensation plan

(9) For the Chief Administrative Officer/CHRO and the Chief of Staff the lump sum value of the RS Plan decreased by $14,752 and $102,560 respectively from 2022 to 2023.

Defined Benefit Plan

As described above, executive employees with a hire date prior to May 1, 2021 are eligible for the RS Plan and participate in either the NRECA Pension Restoration Plan or the NRECA Executive Benefit Restoration Plan. The following table lists the estimated values under the RS Plan and both restoration plans as of December 31, 2024. As a result of changes in Internal Revenue Service regulations, the annual base salary used in determining benefits is limited to $345,000 effective January 1, 2024.

Name	Number of years Credited Service as of December 31, 2024	RS Plan Present Value of Accumulated Benefit as of December 31, 2024	Pension Restoration Plans Present Value of Accumulated Benefit as of December 31, 2024	Payments During 2024
Duane D. Highley (1)	5 years, 9 months	$ —	$ 6,109,540	$ 3,471,573
Patrick L. Bridges (2)	3 years, 11 months	235,492	1,096,392	1,096,392
Elda M. de la Peña	26 years, 8 months	2,001,040	517,239	None
Robert J. Frankmore	10 years, 6 months	485,051	43,876	None

(1) Mr. Highley began employment with us on April 1, 2019. He has 5 years 9 months of service with us and a total of 40 years and 6 months in the RS Plan due to prior years of participation at previous employers. His participation in the NRECA Executive Benefit Restoration Plan started anew on April 1, 2019. Duane Highley received a quasi-retired lump sum on January 8, 2024 from the RS Plan. On January 9, 2024, Mr. Highley began accruing a new pension plan benefit. Number of years credited for the NRECA Executive Benefit Restoration Plan is 5 years, 9 months.

(2) Patrick Bridges received a quasi-retired lump sum on January 6, 2021 from the RS Plan. On January 7, 2021, Mr. Bridges began accruing a new pension plan benefit. Number of years credited for the Pension Restoration Plan is 17 years, 3 months.

The pension benefits indicated above are the estimated amounts payable by the plan, and they are not subject to any deduction for Social Security or other offset amounts. The participant's annual pension at his or her normal retirement date, currently age 62, is equal to the product of his or her years of benefit service multiplied by the average of his or her highest annual salary in five of the last ten years multiplied by 1.9 percent. The value listed in the table is the actual lump sum value that would have been payable to the employee if they had terminated employment on December 31, 2024.

Non-Qualified Executive Deferred Compensation Plan

As described above, executive employees hired May 1, 2021 or later who are not eligible for the RS Plan are eligible for the non-qualified executive deferred compensation plan. The following table lists the contributions during the last fiscal year and balance as of December 31, 2024 for this plan.

Name	Executive contributions in last fiscal year	Our contributions in last fiscal year (1)	Aggregate earnings in last fiscal year	Aggregate withdraws/ distributions	Aggregate balance as of December 31, 2024
Jerome Sturhahn	$ —	$ 40,632	$ 13,868	None	$ 92,270
Todd E. Telesz	—	25,501	—	None	25,501

(1) Our non-qualified executive plan contributions are included in the all other compensation in the Summary Compensation Table above for these individuals.

As described above, the above individuals are eligible for a 10 percent contribution from us to the executive deferred compensation plan.

Chief Executive Officer Pay Ratio

The 2024 compensation disclosure ratio of the median annual total compensation of all our employees to the annual total compensation of our Chief Executive Officer is as follows:

Category and Ratio	2024 Total Compensation (1)
Median annual total compensation of all employees (excluding Chief Executive Officer)	$ 145,179
Annual Total Compensation of Duane D. Highley, Chief Executive Officer	1,741,970
Ratio of the median annual total compensation of all employees to the annual total compensation of Duane D. Highley, Chief Executive Officer	1.0:12

(1) Includes change in pension value from 2023 to 2024 and if the change was negative, zero was used in the calculation.

In determining the median employee, a listing was prepared of all active employees of us and our subsidiaries as of December 31, 2024. We did not make any assumptions, adjustments, or estimates with respect to total compensation, and we did not annualize the compensation for any full-time employees that were not employed by us for all of 2024. We determined the compensation of our median employee by (1) utilizing the W-2 Box 5 wages for all active employees for 2024 and (2) ranking the annual total compensation of the employees, except the Chief Executive Officer, from lowest to highest. To determine if a material difference exists in the total compensation of the median employee compared to other employees when adding the change in pension value for the employee, we added this value to the median employee and to the three employees below and three employees above. After completing this evaluation of the seven employees, it was determined there was a material difference in the pension value of the years of benefit service of the seven employees. Therefore, we changed the median employee after adding the change in pension value to be the median employee of the above mentioned seven employees.

After identifying the median employee, we calculated annual total compensation for such employee using the same methodology we use for our named executive officers as set forth in the above Summary Compensation Table.

Our Chief Executive Officer Pay Ratio is a reasonable estimate calculated in a manner consistent with Item 402(u) of Regulation S-K. However, due to the flexibility afforded by Item 402(u) of Regulation S-K in calculating the Chief Executive Officer Pay Ratio, our Chief Executive Officer Pay Ratio may not be comparable to the Chief Executive Officer pay ratios presented by other companies.

Board of Directors Compensation

Chairman and President of our Board

The Chairman and President of our Board is compensated per Board policy as follows:

1) Due to the duties and responsibilities of the Chairman and President, the allowance paid to the Chairman and President is $160,000 per year paid on a bi-weekly basis. The Chairman and President is also reimbursed for expenses submitted as incurred.

2) The Chairman and President is assigned a company vehicle for business and personal use.

Board of Directors

Our Board, excluding the Chairman and President, are compensated per Board policy as follows:

1) A director will receive a monthly preparation fee of $500.

2) For each day a director attends one or more authorized meetings or events in person, including virtual meetings, the director is entitled to an attendance allowance of $500. For virtual meetings or virtual events that require an hour or less of director time, no allowance will be paid without approval from the Chairman and President or Vice Chairman.

3) The travel day allowance for travel time for directors going to and from the above meetings or events, where one or more days or a partial day of travel is required in addition to the day of the meeting, is up to $500 with the allowance based upon the number of miles the director lives from the location of the meeting.

4) Directors are reimbursed for transportation in connection with the foregoing meetings or events at the published maximum IRS approved mileage rate for use of a personal vehicle, or for the actual commercial plane, bus, rail, rental car and/or ground transportation fares incurred.

5) The allowance for meal expenses of a director incurred in the Denver metropolitan area in connection with attendance at meetings is at the published maximum IRS allowable per diem rate, for the Denver metropolitan area. A director may stay at a hotel approved by us, the Chairman and President, or the Executive Committee in the Denver metropolitan area in connection with attendance at meetings at no charge to the director. All meetings attended by directors outside of the Denver metropolitan area will be reimbursed for actual receipted expenses for meals and lodging incurred at such meetings.

Directors are authorized to attend other meetings or functions at our expense only with the authorization of our Board or the Chairman and President, or in the absence of those, with the authorization of the Vice Chairman upon consultation with and consent of any member of the Executive Committee.

Directors' Deferred Compensation Plan

Our Board, including the Chairman and President of our Board, are eligible to participate in the Directors' Elective Deferred Fees Plan. This plan allows for deferral of director's fees into an unfunded and unsecured plan under Section 409A of the Internal Revenue Code. Under this plan, the funds are held in trust by a third-party bank and the funds are subject to claims by our creditors in the event of insolvency.

Board of Directors Compensation Table

The following table sets forth information concerning fees earned or paid to our Board in 2024 for services rendered. Director fees are earned or paid in cash after submission of receipts to us. Directors are also reimbursed for expenses as described above.

Name	2024 Board Fees (1)
Charles Abel II	$ 20,500
Leroy Anaya	31,625
Robert Baca	31,750
Robert Bledsoe	28,000
Lawrence Brase	24,500

Leo Brekel	11,500
William Bridges	30,000
Robert Brockman	16,750
Matt M. Brown	16,000
Arthur W. Connell	33,500
Kevin Cooney	29,750
Elias Coriz	27,125
Mark Daily (2)	4,500
Jerry Fetterman (2)	10,750
John "Jack" Finnerty (2)	3,000
Joel Gilbert	28,500
Rick Gordon	16,750
Ronald Hilkey	16,000
Larry Hoozee	21,375
Joe Hoskins	28,500
Donald Keairns	41,750
Julie Kilty	33,750
Christopher Martinez (2)	16,500
Thaine Michie	24,250
Stuart Morgan	24,750
Zane Shanon Nunn	12,375
Stanley Propp (2)	23,000
Timothy A. Rabon	153,846
Steve M. Rendon	25,000
Corey Robinson	11,000
Peggy A. Ruble	23,500
Roger L. Schenk	24,162
Gary Shaw	20,875
Darryl Sullivan	23,425
Kevin Thomas	14,200
Clay Thompson	18,750
Douglas Shawn Turner	24,750
Wesley Ulrich	19,250
Morgan Weinberg	16,250
William Wilson	19,125
Scott Wolfe	21,750
Phillip Zochol	15,625

(1) Various directors have deferred a total of $16,800 of the actual Board fee payments made in 2024.

(2) Individual not currently on our Board.

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

Not applicable.

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

Certain Relationships and Related Transactions

Because we are a cooperative, our Members own us. Each of our directors, as required by our Bylaws, is a general manager, director or trustee of the Utility Member that it represents on our Board. Each of our Utility Members has a wholesale electric service contract with us and we received revenue from each of our Utility Members in excess of $120,000 in 2024.

Chris Martinez is the Executive Vice President/General Manager of Columbus Electric Cooperative, Inc. and served as a director on our Board from February 2024 until August 2024. Columbus Electric Cooperative, Inc. is a Utility Member and our revenue from them under our wholesale electric service contract was $8.8 million, or 0.8 percent, of our Utility Member revenue and 0.5 percent of our total operating revenue in 2024.

Other than as described above, in 2024, we had no transactions with any related persons that exceeded $120,000 and there are currently no proposed transactions with any related persons that exceed $120,000.

Our Board has adopted a conflicts of interest policy that sets forth guidelines for the approval of any related party transaction and requires that our directors, senior management, and certain employees annually report and supplement as needed to the Chairman and President of our Board all personal and business relationships that could influence decisions related to our operation and management, as well as any relationships that could give the appearance of influencing such decisions.

Director Independence

Because we are a cooperative, our Members own us. Our Bylaws set forth the specific requirements regarding the composition of our Board. See "DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE –Directors" for a description of these requirements.

In addition to meeting the requirements set forth in our Bylaws, all current directors satisfy the definition of director independence as prescribed by the NASDAQ Stock Market and otherwise meet all the requirements set forth in our Bylaws. Although we do not have any securities listed on the NASDAQ Stock Market, we have used its independence criteria to make this determination in accordance with applicable SEC rules.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The following table presents fees for services provided by our independent registered accounting firms: Deloitte & Touche LLP and Ernst & Young LLP for the 2024 and 2023 fiscal year, respectively.

	2024	2023
Audit Fees (1)	$ 782,200	$ 868,000
Audit-Related Fees (2)	—	—
Tax Fees (3)	27,000	33,500
All Other Fees (4)	—	—
Total	$ 809,200	$ 901,500

(1) Audit of annual consolidated financial statements and review of interim consolidated financial statements included in SEC filings and services rendered in connection with financings, including comfort letters, consents, and comment letters. Also includes audit of the financial statements included in the annual FERC Form 1 filing.

(2) Other audit-related services generally relate to accounting consultations pertaining to accounting standards impacting future periods. There were no such services or related fees during 2023 and 2024.

(3) Professional tax services including tax consulting and tax return compliance.

(4) All other fees.

For the two most recent fiscal years, other than those fees listed above, we did not pay Deloitte & Touche LLP and Ernst & Young LLP any fees for any other products or services.

Pre-Approval Policy

All audit, tax, and other services, and related fees, to be performed by our independent registered accounting firm for us must be reviewed by the Finance and Audit Committee and approved by our Board. In the event that time does not allow for Finance and Audit Committee review and Board pre-approval of non-audit fees, non-audit service may be performed by our independent registered accounting firm if pre-approved by both the Chairman and the Vice-Chairman of the Finance and Audit Committee. The Finance and Audit Committee reviews the description of the services and an estimate of the anticipated costs of performing those services for approval by our Board. Committee review and Board pre-approval is granted usually at regularly scheduled meetings. During 2023 and 2024, all services performed by our independent registered accounting firms were approved or pre-approved in accordance with this policy.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) **List of Documents Filed as a Part of This Report.**

1. Financial Statements

See Index to Financial Statements under Part II, Item 8

2. Financial Statements Schedules

Not Applicable

3. Exhibits

Exhibit Number	Description
3.1†	Amended and Restated Articles of Incorporation of Tri-State Generation and Transmission Association, Inc. (Filed as Exhibit 3.1 to the Registrant's Form 10-K filed on March 5, 2021, File No. 333-212006.)
3.2†	Amended and Restated Bylaws of Tri-State Generation and Transmission Association, Inc., dated August 5, 2021 (Filed as Exhibit 3.2 to the Registrant's Form 10-Q filed on November 10, 2021, File No. 333-212006.)
4.1†	Indenture, dated effective as of December 15, 1999, between Tri-State Generation and Transmission Association, Inc. and U.S. Bank Trust Company, National Association, as (successor) trustee, as supplemented by Supplemental Indenture No. 2, dated June 30, 2000, Supplemental Indenture No. 20, dated July 30, 2009, Supplemental Indenture No. 21, dated October 8, 2009, Supplemental Indenture No. 27, dated July 29, 2011, Supplemental Indenture No. 28, dated March 15, 2012, Supplemental Indenture No. 29, dated December 6, 2012, Supplemental Indenture No. 30, dated July 3, 2013, Supplemental Indenture No. 34, dated October 30, 2014 and Supplemental Indenture No. 38, dated November 21, 2014 (Filed as Exhibit 4.1 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
4.1.1†	Supplemental Master Mortgage Indenture No. 39, dated and effective as of May 23, 2016, between Tri-State Generation and Transmission Association, Inc. and U.S. Bank Trust Company, National Association as (successor) trustee (Filed as Exhibit 4.1 to the Registrant's Form 8-K filed on May 23, 2016, File No. 333-203560.)
4.1.2†	Supplemental Master Mortgage Indenture No. 40, dated and effective as of November 16, 2017, between Tri-State Generation and Transmission Association, Inc. and U.S. Bank Trust Company, National Association as (successor) trustee (Filed as Exhibit 4.1.2 to the Registrant's Form 10-K filed on March 9, 2018, File No. 333-203560.)
4.1.3†	Supplemental Master Mortgage Indenture No. 41, dated and effective as of April 25, 2018, between Tri-State Generation and Transmission Association, Inc. and U.S. Bank Trust Company, National Association as (successor) trustee (Filed as Exhibit 4.1 to the Registrant's Form 8-K filed on April 25, 2018, File No. 333-203560.)
4.1.4†	Supplemental Master Mortgage Indenture No. 42, dated and effective as of December 11, 2018, between Tri-State Generation and Transmission Association, Inc. and U.S. Bank Trust Company, National Association as (successor) trustee (Filed as Exhibit 4.1.4 to the Registrant's Form 10-K filed on March 8, 2019, File No. 333-212006.)
4.1.5†	Supplemental Master Mortgage Indenture No. 43, dated and effective as of June 24, 2020, between Tri-State Generation and Transmission Association, Inc. and U.S. Bank Trust Company, National Association as (successor) trustee (Filed as Exhibit 4.1.5 to the Registrant's Form 10-Q filed on August 12, 2020, File No. 333-212006.)
4.1.6†	Supplemental Master Mortgage Indenture No. 44, dated and effective as of April 25, 2022, between Tri-State Generation and Transmission Association, Inc. and U.S. Bank Trust Company, National Association as (successor) trustee (Filed as Exhibit 4.1 to the Registrant's Form 8-K filed on April 25, 2022, File No. 333-212006.)
4.1.7	Supplemental Master Mortgage Indenture No. 45, dated and effective as of March 23, 2023, between Tri-State Generation and Transmission Association, Inc. and U.S. Bank Trust Company, National Association as (successor) trustee

4.1.8†	Supplemental Master Mortgage Indenture No. 46, dated and effective as of December 19, 2023, between Tri-State Generation and Transmission Association, Inc. and U.S. Bank Trust Company, National Association as (successor) trustee (Filed as Exhibit 4.1.7 to the Registrant's Form 10-K filed on March 15, 2024, File No. 333-212006.)
4.1.9	Supplemental Master Mortgage Indenture No. 47, dated and effective as of December 12, 2024, between Tri-State Generation and Transmission Association, Inc. and U.S. Bank Trust Company, National Association as (successor) trustee
4.2†	Exchange and Registration Rights Agreement, dated October 30, 2014, between Tri-State Generation and Transmission Association, Inc. and Goldman, Sachs & Co. (Filed as Exhibit 4.2 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
4.3†	Form of Exchange Bond for 3.70% First Mortgage Bonds, Series 2014E-1, due 2024 (Filed as Exhibit 4.3 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
4.4†	Form of Exchange Bond for 4.70% First Mortgage Bonds, Series 2014E-2, due 2044 (Filed as Exhibit 4.4 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
4.5†	Exchange and Registration Rights Agreement, dated May 23, 2016, between Tri-State Generation and Transmission Association, Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated, U.S. Bancorp Investments, Inc. and Wells Fargo Securities, LLC (Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on May 23, 2016, File No. 333-203560.)
4.6†	Form of Exchange Bond for 4.25% First Mortgage Bonds, Series 2016A, due 2046 (Filed as Exhibit 4.3 to the Registrant's Form S-4 Registration Statement, File No. 333-212006.)
4.7.1*	Term Loan Agreement, dated December 6, 2012, between Tri-State and CoBank, ACB
4.7.2*	Secured Promissory Note, dated December 6, 2012, from Tri-State to CoBank, ACB, related to Loan No. 002660317, in the original amount of $100,000,000
4.8.1*	Term Loan Agreement, dated October 31, 2014, between Tri-State and CoBank, ACB
4.8.2*	First Amendment to Term Loan Agreement, dated May 25, 2023, between Tri-State and CoBank, ACB
4.8.3*	Promissory Note, dated November 4, 2014, from Tri-State to CoBank, ACB, related to term loan A 002847868, in the original amount of $68,345,000
4.8.4*	Promissory Note, dated November 4, 2014, from Tri-State to CoBank, ACB, related to term loan B 002847716, in the original amount of $102,220,000
4.9.1*	Term Loan Agreement, dated December 11, 2018, between Tri-State and CoBank, ACB
4.9.2*	First Amendment to Term Loan Agreement, dated May 25, 2023, between Tri-State and CoBank, ACB
4.9.3*	Promissory Note, dated December 11, 2018, from Tri-State to CoBank, ACB, related to term loan A 003170483, in the original amount of $55,180,926
4.9.4*	Promissory Note, dated December 11, 2018, from Tri-State to CoBank, ACB, related to term loan B 003170567, in the original amount of $69,819,074
4.10.1*	Term Loan Agreement, dated June 24, 2020, between Tri-State and CoBank, ACB
4.10.2*	First Amendment to Term Loan Agreement, dated May 25, 2023, between Tri-State and CoBank, ACB
4.10.3*	Promissory Note, dated June 24, 2020, from Tri-State to CoBank, ACB, related to term loan No. 30080493, in the original amount of $125,000,000
4.11.1*	Loan Agreement, dated October 31, 2014, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.11.2*	First Amendment to Loan Agreement, dated March 6, 2023, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.11.3*	Secured Promissory Note, dated October 31, 2014, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to Loan C-0047-9077, in the original amount of $102,220,000
4.12.1*	Loan Agreement, dated October 31, 2014, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.12.2*	Secured Promissory Note, dated October 31, 2014, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9078, in the original amount of $68,300,000
4.13.1*	Loan Agreement, dated June 24, 2020, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.13.2*	First Amendment to Loan Agreement, dated March 6, 2023, between Tri-State and National Rural Utilities Cooperative Finance Corporation

4.13.3*	Secured Promissory Note, dated June 24, 2020, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-A-9080, in the original amount of $50,000,000
4.13.4*	Secured Promissory Note, dated June 24, 2020, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-A-9081, in the original amount of $50,000,000
4.14*	Amended and Restated Bond, dated October 2, 2017, pursuant to the Trust Indenture, dated February 1, 2009, between Moffat County, Colorado and U.S. Bank Trust Company, National Association, as (successor) trustee, in the original amount of $46,800,000 related to Pollution Control Refunding Revenue Bonds, Series 2009B.
4.15.1*	Notes, dated October 31, 2014, from Tri-State to various purchasers, relating to Series 2014B Note Purchase Agreement
4.15.2*	Notes, dated December 12, 2017, from Tri-State to various purchasers, relating to 2017 Note Purchase Agreement
4.15.3*	Notes, dated April 12, 2018, from Tri-State to various purchasers, relating to 2017 Note Purchase Agreement
4.16*	Note, dated October 21, 2003, from Springerville Unit 3 Holding to Wilmington Trust Company, relating to Tri-State 2003-Series B Pass Through Trust, in the original amount of $405,000,000, due in 2033
4.17.1*	Tri-State First Mortgage Bond, dated June 8, 2010, related to Series 2010A due in 2040, in the principal amount of $400,000,000
4.17.2*	Tri-State First Mortgage Bond, dated October 8, 2010, related to Series 2010A due in 2040, in the principal amount of $100,000,000
4.18*	Term Loan Agreement, dated as of December 12, 2024, between Tri-State, as borrower, and Wells Fargo Bank, National Association
4.18.1*	Secured Promissory Note, dated December 12, 2024, from Tri-State to Wells Fargo Bank, National Association, relating to Term Loan Agreement, in the original amount of $200,000,000
10.1†	Second Amended and Restated Wholesale Power Contract for the Eastern Interconnection, dated as of September 27, 2017, between Tri-State and Basin Electric Power Cooperative (Filed as Exhibit 10.1 to the Registrant's Form 8-K filed on September 28, 2017, File No. 333-212006.)
10.2†	Wholesale Power Contract for the Western Interconnection, dated as of September 27, 2017, between Tri-State and Basin Electric Power Cooperative (Filed as Exhibit 10.2 to the Registrant's Form 8-K filed on September 28, 2017, File No. 333-212006.)
10.3†	Missouri Basin Power Project—Laramie River Electric Generating Station and Transmission System Participation Agreement, executed on various dates during the months of September, November and December, 1975, taking effect as of May 25, 1977, amongst Basin Electric Power Cooperative, Tri-State, City of Lincoln, Nebraska, Heartland Consumer Power District, Wyoming Municipal Power Agency, and Western Minnesota Municipal Power Agency, as amended by Amendment No. 1, dated as of March 15, 1977, Amendment No. 2, dated as of March 16, 1977, Amendment No. 3, dated as of August 1, 1982, Amendment 4, dated as of September 1, 1982, Amendment No. 5, dated as of May 2, 1983, Amendment No. 6, dated as of March 1, 1986, Amendment No.7, dated as of September 15, 1986, Amendment No. 8, dated as of June 10, 1997, Amendment No. 9, dated as of April 16, 1999, and Amendment No. 10, dated as of July 31, 2014 (Filed as Exhibit 10.2 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
10.3.1†	Amendment No. 12 to Missouri Basin Power Project—Laramie River Electric Generating Station and Transmission System Participation Agreement, dated as of September 20, 2018, amongst Basin Electric Power Cooperative, Tri-State, City of Lincoln, Nebraska, Heartland Consumer Power District, Wyoming Municipal Power Agency, and Western Minnesota Municipal Power Agency (Filed as Exhibit 10.1 to the Registrant's Form 8-K filed on September 26, 2018, File No. 333-203560.)
10.3.2†	Amendment No. 13 to Missouri Basin Power Project—Laramie River Electric Generating Station and Transmission System Participation Agreement, dated as of May 27, 2021, amongst Basin Electric Power Cooperative, Tri-State, City of Lincoln, Nebraska, Wyoming Municipal Power Agency, and Western Minnesota Municipal Power Agency (Filed as Exhibit 10.3.2 to the Registrant's Form 10-Q filed on August 9, 2021, File No. 333-203560.)
10.3.3†	Amendment No. 14 to Missouri Basin Power Project—Laramie River Electric Generating Station and Transmission System Participation Agreement, dated as of May 1, 2023, amongst Basin Electric Power Cooperative, Tri-State, City of Lincoln, Nebraska, and Western Minnesota Municipal Power Agency (Filed as Exhibit 10.3.3 to the Registrant's Form 10-Q filed on May 8, 2023, File No. 333-203560.)
10.4†	Wholesale Electric Service Contract, dated July 1, 2007, between Tri-State and Big Horn Rural Electric Company, together with a schedule identifying 39 other substantially identical Wholesale Electric Service Contracts (Filed as Exhibit 10.4 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)

10.5†	Participation Agreement, dated as of October 21, 2003, among Tri-State, as Construction Agent and as Lessee, Computershare Trust Company, N.A., as (successor) Independent Manager, Springerville Unit 3 Holding LLC, as Owner Lessor, Springerville Unit 3 OP LLC, as Owner Participant, and Wilmington Trust Company, as Series A Pass Through Trustee and Series B Pass Through Trustee and as Indenture Trustee (Filed as Exhibit 10.5 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
10.5.1†	First Amendment to Participation Agreement, effective as of July 1, 2022, among Tri-State, as Construction Agent and as Lessee, Computershare Trust Company, N.A., as (successor) Independent Manager, Springerville Unit 3 Holding LLC, as Owner Lessor, Springerville Unit 3 OP LLC, as Owner Participant, and Wilmington Trust Company, as Indenture Trustee (Filed as Exhibit 10.5.1 to the Registrant's Form 10-K filed on March 10, 2023, File No. 333-203560).
10.6.1†	Supplemental Master Mortgage Indenture No. 23, dated as of June 8, 2010, between U.S. Bank Trust Company, National Association, as (successor) trustee, and Tri-State in connection with Series 2010A Secured Obligations (Filed as Exhibit 10.6.1 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
10.6.2†	Supplemental Master Mortgage Indenture No. 24, dated as of October 8, 2010, between U.S. Bank Trust Company, National Association, as (successor) trustee, and Tri-State in connection with reopening and amending of Series 2010A Secured Obligations (Filed as Exhibit 10.6.2 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
10.7†	2014 Note Purchase Agreement, dated as of October 31, 2014, between Tri-State and various purchasers of the notes identified therein (Filed as Exhibit 10.8 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
10.8†	Amended and Restated Credit Agreement, dated as of April 25, 2022, amongst Tri-State, as borrower, each lender from time to time party thereto, including National Rural Utilities Cooperative Finance Corporation, as administrative agent (Filed as Exhibit 10.1 to the Registrant's Form 8-K filed on April 25, 2022, File No. 333-203560.)
10.8.1†	Amendment No. 1 to Amended and Restated Credit Agreement, dated as of June 15, 2023, amongst Tri-State, as borrower, each lender from time to time party thereto, including the National Rural Utilities Cooperative Finance Corporation, as administrative agent (Filed as Exhibit 10.8.1 to the Registrant's Form 10-Q filed on August 10, 2023, File No. 333-203560.)
10.9†	Form of Commercial Paper Dealer Agreement between Tri-State, as issuer, and the Dealer party thereto (Filed as Exhibit 10.1 to the Registrant's Form 8-K filed on May 13, 2016, File No. 333-203560.)
10.9.1†	Form of First Amendment to Commercial Paper Dealer Agreement between Tri-State, as issuer, and the Dealer party thereto (Filed as Exhibit 10.10.1 to the Registrant's Form 10-Q filed on August 9, 2021, File No. 333-203560.)
10.10†	Turnkey Engineering, Procurement and Construction Contract (Axial Basin Solar Project), dated March 15, 2024, between Tri-State and JSI Construction Group LLC (Filed as Exhibit 10.1 to the Registrant's Form 8-K filed on March 20, 2024, File No. 333-203560.)
10.11**†	Directors' Elective Deferred Fees Plan, effective January 1, 2005, executed December 11, 2008 (Filed as Exhibit 10.10 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
10.12**†	Executive Benefit Restoration Plan, dated December 12, 2014, as amended by Amendment effective July 30, 2020 (Filed as Exhibit 10.2 to the Registrant's Form 10-K filed on March 5, 2021, File No. 333-212006.)
10.12.1**†	Executive Benefit Restoration Plan of Tri-State Generation and Transmission Association, Inc. - Amendment No. 2, effective May 1, 2021 (Filed as Exhibit 10.12.1 to the Registrant's Form 10-Q filed on May 7, 2021, File No. 333-203560.)
10.13**†	Amended and Restated Pension Restoration Plan of Tri-State Generation and Transmission Association, Inc., dated December 12, 2014 (Filed as Exhibit 10.19 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
19.1	Board Policy for Insider Trading
21.1	Subsidiaries of Tri-State Generation and Transmission Association, Inc.
31.1	Rule 13a-14(a)/15d-14(a) Certification, by Duane Highley (Principal Executive Officer).
31.2	Rule 13a-14(a)/15d-14(a) Certification, by Todd E. Telesz (Principal Financial Officer).
32.1	Certification Pursuant to 18 U.S.C. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Duane Highley (Principal Executive Officer).
32.2	Certification Pursuant to 18 U.S.C. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Todd E. Telesz (Principal Financial Officer).

95	Mine Safety and Health Administration Safety Data.
101	XBRL Interactive Data File.

* Pursuant to Item 601(b)(4)(iii) of Regulation S-K, this document(s) is not filed herewith. We hereby agree to furnish a copy to the SEC upon request.

** Management contract or compensatory plan arrangement.

† Incorporated herein by reference.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

Date: March 19, 2025

By: /s/ DUANE HIGHLEY

Name: Duane Highley

Title: Chief Executive Officer

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, this report has been signed by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ DUANE HIGHLEY Duane Highley	Chief Executive Officer (principal executive officer)	March 19, 2025
/s/ TODD E. TELESZ Todd E. Telesz	Senior Vice President/Chief Financial Officer (principal financial officer)	March 19, 2025
/s/ DENNIS J. HRUBY Dennis J. Hruby	Vice President Controller (principal accounting officer)	March 19, 2025
/s/ TIMOTHY A. RABON Timothy A. Rabon	Chairman, President and Director	March 19, 2025
/s/ DONALD KEAIRNS Donald Keairns	Director	March 19, 2025
/s/ JULIE KILTY Julie Kilty	Director	March 19, 2025
/s/ STUART MORGAN Stuart Morgan	Director	March 19, 2025
/s/ THAINE MICHIE Thaine Michie	Director	March 19, 2025
/s/ SCOTT WOLFE Scott Wolfe	Director	March 19, 2025
/s/ CHARLES ABEL II Charles Abel II	Director	March 19, 2025
Arthur W. Connell	Director	
/s/ DOUGLAS SHAWN TURNER Douglas Shawn Turner	Director	March 19, 2025
/s/ LEROY ANAYA Leroy Anaya	Director	March 19, 2025
/s/ ROBERT BACA Robert Baca	Director	March 19, 2025
Lucas Bear	Director	

/s/ ROBERT BLEDSOE Robert Bledsoe	Director	March 19, 2025
/s/ LAWRENCE BRASE Lawrence Brase	Director	March 19, 2025
/s/ LEO BREKEL Leo Brekel	Director	March 19, 2025
/s/ WILLIAM BRIDGES William Bridges	Director	March 19, 2025
/s/ ROBERT BROCKMAN Robert Brockman	Director	March 19, 2025
/s/ MATT M. BROWN Matt M. Brown	Director	March 19, 2025
/s/ KEVIN COONEY Kevin Cooney	Director	March 19, 2025
Elias Coriz	Director	
/s/ JOEL GILBERT Joel Gilbert	Director	March 19, 2025
/s/ RICK GORDON Rick Gordon	Director	March 19, 2025
/s/ RONALD HILKEY Ronald Hilkey	Director	March 19, 2025
/s/ LARRY HOOZEE Larry Hoozee	Director	March 19, 2025
/s/ JOE HOSKINS Joe Hoskins	Director	March 19, 2025
/s/ ZANE SHANON NUNN Zane Shanon Nunn	Director	March 19, 2025
/s/ STEVE M. RENDON Steve M. Rendon	Director	March 19, 2025
/s/ COREY ROBINSON Corey Robinson	Director	March 19, 2025
/s/ PEGGY A. RUBLE Peggy A. Ruble	Director	March 19, 2025
/s/ ROGER L. SCHENK Roger L. Schenk	Director	March 19, 2025
/s/ GARY SHAW Gary Shaw	Director	March 19, 2025
/s/ KEVIN STUART Kevin Stuart	Director	March 19, 2025
Darryl Sullivan	Director	

/s/ KEVIN THOMAS Kevin Thomas	Director	March 19, 2025
/s/ CLAY THOMPSON Clay Thompson	Director	March 19, 2025
/s/ WESLEY ULLRICH Wesley Ullrich	Director	March 19, 2025
/s/ MORGAN WEINBERG Morgan Weinberg	Director	March 19, 2025
/s/ WILLIAM WILSON William Wilson	Director	March 19, 2025
/s/ PHILLIP ZOCHOL Phillip Zochol	Director	March 19, 2025