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

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2023
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)

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 the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. **Large accelerated filer** ☐ **Accelerated filer** ☐

Non-accelerated Filer ☒ **Smaller reporting company** ☐ **Emerging growth company** ☐

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

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

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

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

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.
INDEX TO QUARTERLY REPORT ON FORM 10-Q
FOR THE QUARTER ENDED SEPTEMBER 30, 2023

GLOSSARY

The following abbreviations and acronyms used in this quarterly report on Form 10-Q 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
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
Basin	Basin Electric Power Cooperative
Board	Board of Directors
CAISO	California Independent System Operator
CFC	National Rural Utilities Cooperative Finance Corporation
CoBank	CoBank, ACB
Colowyo Coal	Colowyo Coal Company L.P., a subsidiary of ours
COPUC	Colorado Public Utilities Commission
D.C. Circuit Court of Appeals	United States Court of Appeals for the District of Columbia Circuit
DSR	Debt Service Ratio (as defined in our Master Indenture)
ECR	Equity to Capitalization Ratio (as defined in our Master Indenture)
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings Inc.
FPA	Federal Power Act, as amended
GAAP	accounting principles generally accepted in the United States
kWh	kilowatt hour
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.
MW	megawatt
MWh	megawatt hour
Non-Utility Members	our non-utility members
OATT	Open Access Transmission Tariff
S&P	S & P Global Ratings
Salt River Project	Salt River Project Agricultural Improvement and Power District
SEC	Securities and Exchange Commission
Springerville Partnership	Springerville Unit 3 Partnership LP, a subsidiary of ours
Springerville Unit 3	Springerville Generating Station Unit 3
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.
Utility Members	our electric distribution member systems, consisting of both Class A members and Class B members

FORWARD-LOOKING STATEMENTS

This quarterly report on Form 10-Q 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, business strategy, member withdraws 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,” “are expected to,” “will continue,” “is anticipated,” “estimated,” “forecast,” “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. FINANCIAL INFORMATION
Item 1. Financial Statements
Tri-State Generation and Transmission Association, Inc.
Consolidated Statements of Financial Position
(dollars in thousands)

	September 30, 2023	December 31, 2022
ASSETS	(Unaudited)	
Property, plant and equipment		
Electric plant		
In service	$ 5,689,962	$ 5,659,423
Construction work in progress	146,428	81,555
Total electric plant	**5,836,390**	**5,740,978**
Less allowances for depreciation and amortization	(2,457,302)	(2,392,363)
Net electric plant	**3,379,088**	**3,348,615**
Other plant	942,854	954,144
Less allowances for depreciation, amortization and depletion	(702,024)	(694,774)
Net other plant	**240,830**	**259,370**
Total property, plant and equipment	**3,619,918**	**3,607,985**
Other assets and investments		
Investments in other associations	176,526	177,477
Investments in and advances to coal mines	1,602	1,914
Restricted cash and investments	3,753	4,257
Other noncurrent assets	16,663	15,828
Total other assets and investments	**198,544**	**199,476**
Current assets		
Cash and cash equivalents	167,682	105,852
Restricted cash and investments	17,445	573
Deposits and advances	36,449	34,233
Accounts receivable—Utility Members	108,522	103,246
Other accounts receivable	20,260	32,436
Coal inventory	51,598	34,723
Materials and supplies	102,960	93,514
Total current assets	**504,916**	**404,577**
Deferred charges		
Regulatory assets	625,644	650,421
Prepayment—NRECA Retirement Security Plan	6,715	10,745
Other	36,233	40,445
Total deferred charges	**668,592**	**701,611**
Total assets	**$ 4,991,970**	**$ 4,913,649**
EQUITY AND LIABILITIES		
Capitalization		
Patronage capital equity	$ 976,704	$ 984,865
Accumulated other comprehensive loss	(803)	(468)
Noncontrolling interest	131,742	126,180
Total equity	**1,107,643**	**1,110,577**
Long-term debt	2,939,265	2,869,963
Total capitalization	**4,046,908**	**3,980,540**
Current liabilities		
Utility Member advances	20,158	17,070
Accounts payable	118,448	109,109
Short-term borrowings	100	274,102
Accrued expenses	30,798	42,506
Current asset retirement obligations	8,207	5,419
Accrued interest	43,721	25,431
Accrued property taxes	30,176	36,477
Current maturities of long-term debt	393,802	92,920
Total current liabilities	**645,410**	**603,034**
Deferred credits and other liabilities		
Regulatory liabilities	12,715	49,931
Deferred income tax liability	19,851	19,275
Asset retirement and environmental reclamation obligations	176,312	181,588
Other	79,809	68,374
Total deferred credits and other liabilities	**288,687**	**319,168**
Accumulated postretirement benefit and postemployment obligations	10,965	10,907
Total equity and liabilities	**$ 4,991,970**	**$ 4,913,649**

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	**2022**	**2023**	**2022**
Operating revenues				
Utility Member electric sales	$ 357,576	$ 362,442	$ 923,977	$ 931,257
Non-member electric sales	51,294	55,669	111,729	110,029
Rate stabilization	14,041	32,950	36,862	58,295
Provision for rate refunds	(210)	(2,039)	94	759
Other	15,618	16,971	48,162	42,817
	438,319	**465,993**	**1,120,824**	**1,143,157**
Operating expenses				
Purchased power	120,250	128,202	316,356	321,240
Fuel	71,241	94,770	197,944	225,491
Production	44,758	40,045	142,733	128,095
Transmission	47,098	47,054	142,406	136,289
General and administrative	19,663	18,658	61,738	57,824
Depreciation, amortization and depletion	43,120	46,604	128,191	133,347
Coal mining	3,834	1,814	9,603	7,189
Other	2,345	2,288	11,057	50,626
	352,309	**379,435**	**1,010,028**	**1,060,101**
Operating margins	**86,010**	**86,558**	**110,796**	**83,056**
Other income				
Interest	2,343	1,097	5,153	2,883
Capital credits from cooperatives	1,145	743	3,103	5,338
Other income	3,852	1,751	5,894	2,621
	7,340	**3,591**	**14,150**	**10,842**
Interest expense				
Interest	45,558	38,419	128,924	109,409
Interest charged during construction	(1,238)	(341)	(3,328)	(1,133)
	44,320	**38,078**	**125,596**	**108,276**
Income tax expense (benefit)	23	(312)	67	(275)
Net margins including noncontrolling interest	**49,007**	**52,383**	**(717)**	**(14,103)**
Net margin attributable to noncontrolling interest	(2,526)	(2,130)	(7,444)	(6,266)
Net margins attributable to the Association	**$ 46,481**	**$ 50,253**	**$ (8,161)**	**$ (20,369)**

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	**2022**	**2023**	**2022**
Net margins including noncontrolling interest	$ 49,007	$ 52,383	$ (717)	$ (14,103)
Other comprehensive loss:				
Unrealized gain (loss) on securities available for sale	10	(127)	26	(360)
Amortization of prior service credit on postretirement benefit obligation included in net margin	(409)	(535)	(1,228)	(1,604)
Amortization of prior service cost on executive benefit restoration obligation included in net margin	289	283	867	849
Other comprehensive loss	**(110)**	**(379)**	**(335)**	**(1,115)**
Comprehensive income (loss) including noncontrolling interest	**48,897**	**52,004**	**(1,052)**	**(15,218)**
Net comprehensive income attributable to noncontrolling interest	(2,526)	(2,130)	(7,444)	(6,266)
Comprehensive income (loss) attributable to the Association	**$ 46,371**	**$ 49,874**	**$ (8,496)**	**$ (21,484)**

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	**2022**	**2023**	**2022**
Patronage capital equity at beginning of period	$ 930,223	$ 924,243	$ 984,865	$ 994,865
Net margins attributable to the Association	46,481	50,253	(8,161)	(20,369)
Patronage capital equity at end of period	**976,704**	**974,496**	**976,704**	**974,496**
Accumulated other comprehensive loss at beginning of period	(693)	(2,196)	(468)	(1,460)
Unrealized gain (loss) on securities available for sale	10	(127)	26	(360)
Reclassification adjustment of prior service credit on postretirement benefit obligation included in net margin	(409)	(535)	(1,228)	(1,604)
Reclassification adjustment for prior service cost on executive benefit restoration obligation included in net margin	289	283	867	849
Accumulated other comprehensive loss at end of period	**(803)**	**(2,575)**	**(803)**	**(2,575)**
Noncontrolling interest at beginning of period	130,149	122,894	126,180	119,100
Net comprehensive income attributable to noncontrolling interest	2,526	2,130	7,444	6,266
Equity distribution to noncontrolling interest	(933)	(978)	(1,882)	(1,320)
Noncontrolling interest at end of period	**131,742**	**124,046**	**131,742**	**124,046**
Total equity at end of period	**$ 1,107,643**	**$ 1,095,967**	**$ 1,107,643**	**$ 1,095,967**

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

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

	Nine Months Ended September 30,	
	2023	**2022**
Operating activities		
Net margins including noncontrolling interest	$ (717)	$ (14,103)
Adjustments to reconcile net margins to net cash provided by operating activities:		
Depreciation, amortization and depletion	128,191	133,347
Amortization of NRECA Retirement Security Plan prepayment	4,029	4,029
Amortization of debt issuance costs	1,801	2,540
Impairment loss	—	30,153
Deferred impairment loss	—	(30,153)
Deposits associated with generator interconnection requests	11,601	6,626
Rate stabilization revenue	(36,862)	(58,295)
Capital credit allocations from cooperatives and income from coal mines under refund distributions	1,263	1,283
Changes in operating assets and liabilities:		
Accounts receivable	4,389	(23,666)
Coal inventory	(16,875)	19,499
Materials and supplies	(9,446)	(5,486)
Accounts payable and accrued expenses	1,078	14,837
Accrued interest	17,290	17,110
Accrued property taxes	(6,301)	(4,312)
New Horizon Mine environmental obligation	—	44,869
Other	5,271	(12,517)
Net cash provided by operating activities	**104,712**	**125,761**
Investing activities		
Purchases of plant	(119,081)	(82,846)
Changes in deferred charges	2,078	(5,849)
Proceeds from other investments	—	94
Net cash used in investing activities	**(117,003)**	**(88,601)**
Financing activities		
Changes in Member advances	3,416	2,717
Payments of long-term debt	(81,010)	(223,578)
Proceeds from issuance of long-term debt	450,000	—
Debt issuance costs	(605)	(1,377)
Change in short-term borrowings, net	(273,502)	214,488
Retirement of patronage capital	(5,446)	(4,564)
Equity distribution to noncontrolling interest	(1,882)	(1,320)
Other	(482)	(445)
Net cash provided by (used in) financing activities	**90,489**	**(14,079)**
Net increase in cash, cash equivalents and restricted cash and investments	**78,198**	**23,081**
Cash, cash equivalents and restricted cash and investments – beginning	**110,682**	**105,136**
Cash, cash equivalents and restricted cash and investments – ending	**$ 188,880**	**$ 128,217**
Supplemental cash flow information:		
Cash paid for interest	$ 108,407	$ 88,993
Cash paid for income taxes	$ —	$ —
Supplemental disclosure of noncash investing and financing activities:		
Change in plant expenditures included in accounts payable	$ (395)	$ (2,783)

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

Tri-State Generation and Transmission Association, Inc.
Notes to Unaudited Consolidated Financial Statements
For the Three and Nine Months Ended September 30, 2023 and 2022

NOTE 1 – PRESENTATION OF FINANCIAL INFORMATION

The accompanying unaudited consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States (“GAAP”) for interim financial information and pursuant to the rules and regulations of the Securities and Exchange Commission (“SEC”). Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. These unaudited consolidated financial statements should be read in conjunction with the financial statements and notes thereto included in our annual report on Form 10-K for the year ended December 31, 2022 filed with the SEC. In the opinion of management, all adjustments, consisting of normal recurring accruals considered necessary for a fair presentation, have been included. Our consolidated financial position as of September 30, 2023, results of operations for the three and nine months ended September 30, 2023 and 2022, and cash flows for the nine months ended September 30, 2023 and 2022 are not necessarily indicative of the results that may be expected for an entire year or any other period.

Basis of Consolidation

We are 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 forty-two 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 (“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 December 23, 2019, our stated rate to our Class A members was filed at FERC and was accepted by FERC on March 20, 2020. On August 2, 2021, FERC approved our settlement agreement related to our stated rate to our Class A members. On June 16, 2023, we filed with FERC a new Class A rate that uses a formula rate and requested for the new rate to take effect on January 1, 2024. We anticipate FERC will accept, subject to refund, our Class A formula rate filing during the fourth quarter of 2023. See Note 17 – Legal.

We comply with the Uniform System of Accounts as prescribed by FERC. In conformity with GAAP, the accounting policies and practices applied by us in the determination of rates are also employed for financial reporting purposes.

The accompanying financial statements reflect the consolidated accounts of Tri-State Generation and Transmission Association, Inc. (“Tri-State”, “we”, “our”, “us” or “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 16 – Variable Interest Entities. Our consolidated financial statements also include our undivided interests in jointly owned facilities. We have eliminated all intercompany balances and transactions in consolidation.

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 other operating expenses is included in our consolidated financial statements.

Our share in each jointly owned facility is as follows as of September 30, 2023 (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 %	$ 391,756	$ 266,901	$ 579
MBPP - Laramie River Station	28.50 %	532,765	345,659	726
Total		$ 924,521	$ 612,560	$ 1,305

NOTE 2 – 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 of Directors ("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 that 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. Expected recovery of 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 expense concurrent with their recovery through rates.

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

	September 30, 2023	December 31, 2022
Regulatory assets		
Deferred income tax expense (1)	$ 19,787	$ 19,279
Deferred prepaid lease expense – Springerville Unit 3 Lease (2)	75,124	76,842
Goodwill – J.M. Shafer (3)	38,461	40,598
Goodwill – Colowyo Coal (4)	33,320	34,095
Deferred debt prepayment transaction costs (5)	108,574	115,045
Deferred Holcomb expansion impairment loss (6)	75,964	79,470
Unrecovered plant (7)	274,414	285,092
Total regulatory assets	**625,644**	**650,421**
Regulatory liabilities		
Interest rate swap - realized gain (8) and other	1,987	2,341
Membership withdrawal (9)	10,728	47,590
Total regulatory liabilities	**12,715**	**49,931**
Net regulatory asset	**$ 612,929**	**$ 600,490**

(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 through rates.

(3) Represents goodwill related to our acquisition of an entity that owned J.M. Shafer Generating Station in December 2011. Goodwill is being amortized to depreciation, amortization and depletion expense in the amount of $2.8 million annually through the 25-year period ending in 2036 and recovered from our Utility Members through rates.

(4) Represents goodwill related to our acquisition of Colowyo Coal Company LP ("Colowyo Coal") in December 2011. Goodwill is being amortized to depreciation, amortization and depletion expense in the amount of $1.0 million annually through the 44-year period ending in 2056 and recovered from our Utility Members through rates.

(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 through 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 depreciation, amortization and depletion expense in the amount of $4.7 million annually over the 20-year period ending in 2039 and recovered from our Utility Members through rates.
(7) Represents deferral of the impairment losses and other closure costs related to the early retirement of the Escalante and Rifle Generating Stations. 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 December 2045 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 December 2028 and recovered from our Utility Members in rates.
(8) 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.
(9) Represents the deferral of the recognition of other operating revenues related to the withdrawal of former Utility Members from membership in us. The deferred membership withdrawal income will be refunded to Utility Members through reduced rates when recognized in operating revenues in future periods. For the nine months ended September 30, 2023, $36.9 million was recognized in operating revenues as part of our rate stabilization measures.

NOTE 3 – 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):

	September 30, 2023	December 31, 2022
Basin Electric Power Cooperative	$ 127,640	$ 127,640
National Rural Utilities Cooperative Finance Corporation - patronage capital	12,451	12,172
National Rural Utilities Cooperative Finance Corporation - capital term certificates	15,054	15,054
CoBank, ACB	15,585	16,727
Other	5,796	5,884
Investments in other associations	**$ 176,526**	**$ 177,477**

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 the nine months ended September 30, 2023 or during 2022.

NOTE 4 – 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 are amounts that have been restricted by contract that 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 for amounts restricted by contract or other legal reasons that 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.

NOTE 5 – CONTRACT ASSETS AND CONTRACT LIABILITIES

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 12 – 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. During the nine months ended September 30, 2023, we recognized $0.7 million of this unearned revenue in other operating revenues on our consolidated statements of operations.

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

	September 30, 2023	December 31, 2022
Accounts receivable - Utility Members	**$ 108,522**	**$ 103,246**
Other accounts receivable - trade:		
Non-member electric sales	10,473	17,213
Other	9,482	9,141
Total other accounts receivable - trade	**19,955**	**26,354**
Other accounts receivable - nontrade	305	6,082
Total other accounts receivable	**$ 20,260**	**$ 32,436**
Contract liabilities (unearned revenue)	**$ 4,374**	**$ 5,123**

NOTE 6 – OTHER DEFERRED CHARGES

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

	September 30, 2023	December 31, 2022
Preliminary surveys and investigations	$ 13,241	$ 13,048
Advances to operating agents of jointly owned facilities	5,080	7,324
Operating lease right-of-use assets	5,960	6,771
Other	11,952	13,302
Total other deferred charges	**$ 36,233**	**$ 40,445**

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 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 14 – Leases.

NOTE 7 – 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 debt service ratio ("DSR") requirement on an annual basis and an equity to capitalization ratio ("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 $300 million outstanding of Term SOFR rate borrowings under the 2022 Revolving Credit Agreement as of September 30, 2023. As of September 30, 2023, we had $220.0 million in availability (including $220 million under the commercial paper back-up sublimit) under the 2022 Revolving Credit Agreement.

Long-term debt consists of the following (dollars in thousands):

	September 30, 2023	December 31, 2022
Total debt	$ 3,350,971	$ 2,981,481
Less debt issuance costs	(20,286)	(21,481)
Less debt discounts	(8,750)	(8,960)
Plus debt premiums	11,132	11,843
Total debt adjusted for debt issuance costs, discounts and premiums	**3,333,067**	**2,962,883**
Less current maturities	(393,802)	(92,920)
Long-term debt	**$ 2,939,265**	**$ 2,869,963**

NOTE 8 – 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.

Short-term borrowings consisted of the following (dollars in thousands):

	September 30, 2023	December 31, 2022
Short-term borrowings - other	$ 100	$ —
Commercial paper outstanding, net of discounts	$ —	$ 274,102
Weighted average interest rate	— %	4.61 %

As of September 30, 2023, we had no commercial paper outstanding and $220 million of the commercial paper back-up sublimit remained available under the 2022 Revolving Credit Agreement. See Note 7 – Long-Term Debt.

NOTE 9 – ASSET RETIREMENT AND ENVIRONMENTAL RECLAMATION OBLIGATIONS

We account for current obligations associated with the future retirement of tangible long-lived assets and environmental reclamation 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 reclamation 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 reclamation estimates are reflected in earnings in the period an estimate is revised.

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. One pit at the Colowyo Mine began final reclamation in 2020 with the other remaining pits still being actively mined.

Generation: We have asset retirement obligations related to equipment, dams, ponds, wells and underground storage tanks at the generating stations.

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

	Nine Months Ended September 30, 2023
Obligations at beginning of period	$ 187,008
Liabilities settled	(2,570)
Accretion expense	3,983
Change in estimate	(3,902)
Total obligations at end of period	**$ 184,519**
Less current obligations at end of period	(8,207)
Long-term obligations at end of period	**$ 176,312**

The New Horizon Mine environmental remediation liability is $67.3 million as of September 30, 2023. Of this amount, $36.8 million is recorded on a discounted basis, using a discount rate of 3.25 percent, with total estimated undiscounted future cash outflows of $57.9 million. Environmental obligation expense is included in other operating expenses on our consolidated statements of operations. Although the entire environmental obligation has been previously expensed, we have sought future rate recovery in our rate filing that we filed with FERC in June 2023. We anticipate FERC will accept, subject to refund, our Class A formula rate filing during the fourth quarter of 2023, at which time we intend to reverse the approximate $44 million of environmental obligation expense 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. 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 10 – OTHER DEFERRED CREDITS AND OTHER LIABILITIES

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

	September 30, 2023	December 31, 2022
Transmission easements	$ 18,114	$ 18,636
OATT deposits	28,344	17,476
Financial liabilities - reclamation	12,009	12,429
Customer deposits	11,279	8,616
Contract liabilities (unearned revenue) - noncurrent	3,252	3,765
Operating lease liabilities - noncurrent	994	1,251
Other	5,817	6,201
Total other deferred credits and other liabilities	**$ 79,809**	**$ 68,374**

In 2015, we renewed transmission right-of-way easements on tribal nation lands where certain of our electric transmission lines are located. $26.4 million will be paid by us for these easements from 2023 through the individual easement terms ending between 2036 and 2040. The present values for the remaining easement payments were $18.1 million and $18.6 million as of September 30, 2023 and December 31, 2022, respectively, which are 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 should the interconnection or transmission request not move forward.

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

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. See Note 14 – Leases.

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.

NOTE 11 – EMPLOYEE BENEFIT PLANS

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 post employment medical benefits to employees on long-term disability. The plans were unfunded as of September 30, 2023, 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 post employment obligations on our consolidated statements of financial position as follows (dollars in thousands):

	Nine Months Ended September 30, 2023
Postretirement medical benefit obligation at beginning of period	$ 2,092
Interest cost	35
Benefit payments (net of contributions by participants)	(432)
Postretirement medical benefit obligation at end of period	**$ 1,695**
Postemployment medical benefit obligation at end of period	329
Total postretirement and postemployment medical obligations at end of period	**$ 2,024**

The service cost component of our net periodic benefit cost, if any, 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 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 postretirement medical benefit obligation.

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

	Nine Months Ended September 30, 2023
Amounts included in accumulated other comprehensive income at beginning of period	$ 2,078
Amortization of prior service credit into other income	(1,228)
Amounts included in accumulated other comprehensive income at end of period	**$ 850**

Defined Benefit Plans

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 post employment obligations on our consolidated statements of financial position as follows (dollars in thousands):

	Nine Months Ended September 30, 2023
Executive benefit restoration obligation at beginning of period	$ 8,486
Service cost	225
Interest cost	231
Executive benefit restoration at end of period	**$ 8,942**
Fair value of plan assets at beginning of period	$ 9,808
Actual return on plan assets	214
Fair value of plan assets at end of period	**$ 10,022**
Net liability recognized at end of period	**$ (1,080)**

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 established 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):

	Nine Months Ended September 30, 2023
Accumulated other comprehensive loss at beginning of period	$ (2,105)
Amortization of prior service cost into other income	867
Accumulated other comprehensive loss at end of period	**$ (1,238)**

NOTE 12 – 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 forty-two Utility Members extend through 2050.

Member electric sales

Revenues from wholesale electric power sales to our Utility Members are primarily from our Class A rate schedule filed with FERC. Our Class A rate schedule for electric power sales to our Utility Members consist of three billing components: an energy rate and two demand rates. Our Class A rate schedule is variable and is approved by our Board and FERC. 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 – Utility Members on our consolidated statements of financial position.

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):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	**2022**	**2023**	**2022**
Non-member electric sales:				
Long-term contracts	$ 9,731	$ 13,682	$ 31,527	$ 38,932
Short-term contracts	41,563	41,987	80,202	71,097
Rate stabilization	14,041	32,950	36,862	58,295
Provision for rate refunds	(210)	(2,039)	94	759
Coal sales	3,675	1,688	8,069	5,112
Other	11,943	15,283	40,093	37,705
Total non-member electric sales and other operating revenue	**$ 80,743**	**$ 103,551**	**$ 196,847**	**$ 211,900**

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.

Rate stabilization revenue

We recognized $14.0 million and $36.9 million of deferred membership withdrawal income for the three and nine months ended September 30, 2023, respectively, as directed by our Board. See Note 2 - Accounting for Rate Regulation.

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. We recognize coal sales revenue in other operating revenue on our consolidated statements of operations.

Other operating revenue

Other operating revenue consists primarily of wheeling and transmission revenue. Other operating revenue also includes revenue we receive from our Non-Utility Members. Wheeling revenue is earned 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.

NOTE 13 – 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. Effective January 1, 2020, we adopted the normalization method of recognizing deferred income taxes pursuant to FERC regulation. Under the normalization method, changes in deferred tax assets or liabilities result in deferred income tax expense (benefit) and any recorded income tax expense (benefit) therefore includes both the current income tax expense (benefit) and the deferred income tax expense (benefit).

Our subsidiaries are not subject to FERC regulation and continue to use a 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.

Under ASC 740-270, we calculate an estimate of the provision for income taxes during interim reporting periods by applying an estimate of the annual effective tax rate for the full fiscal year to income or loss (pretax income or loss excluding unusual or infrequently occurring discrete items) for the reporting period, after regulatory affect. Our consolidated statements of operations included an income tax expense of $67 thousand for the nine months ended September 30, 2023 and an income tax benefit of $275 thousand for the comparable period in 2022.

On August 16, 2022, the Inflation Reduction Act of 2022 (the "IRA") was enacted into law. The IRA enacted many provisions intended to mitigate climate change by providing various sources of funding and tax credit incentives for investments designed to reduce greenhouse gas emissions. These provisions do not impact our current consolidated financial statements but could affect future financial statements due to the impact of such investments. These provisions are subject to regulations and other guidance to be released by the U.S. Department of the Treasury, the U.S. Department of Agriculture and other governmental agencies over time. We are monitoring developments and evaluating opportunities to utilize these incentives. In September 2023, we submitted a Letter of Interest to apply for funding through the U.S. Department of Agriculture's Empowering Rural America ("New ERA") Program. The New ERA Program implements the $9.7 billion funded in the IRA.

NOTE 14 – LEASES

Leasing Arrangements as Lessee

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.

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 expense.

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 $0.6 million for the three months ended September 30, 2023 and $0.6 million for the comparable period in 2022. Rent expense for all short-term and long-term operating leases was $1.8 million for the nine months ended September 30, 2023 and $2.1 million for the comparable period in 2022. 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. As of September 30, 2023, there were no arrangements accounted for as finance leases.

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

	September 30, 2023	December 31, 2022
Operating leases		
Operating lease right-of-use assets	$ 8,696	$ 8,784
Less: Accumulated amortization	(2,736)	(2,013)
Net operating lease right-of-use assets	**$ 5,960**	**$ 6,771**
Operating lease liabilities - current	$ (358)	$ (441)
Operating lease liabilities - noncurrent	(994)	(1,251)
Total operating lease liabilities	**$ (1,352)**	**$ (1,692)**
Operating leases		
Weighted average remaining lease term (years)	7.9	7.6
Weighted average discount rate	3.94 %	3.87 %

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

Year 1	$ 366
Year 2	202
Year 3	91
Year 4	365
Year 5	92
Thereafter	461
Total lease payments	**$ 1,577**
Less imputed interest	(225)
Total	**$ 1,352**

Leasing Arrangements as Lessor

We have lease agreements as lessor for certain operational assets. The revenue from these lease agreements of $1.7 million and $1.7 million for the three months ended September 30, 2023 and 2022, respectively, and $5.1 million and $5.2 million for the nine months ended September 30, 2023 and 2022, respectively, are included in other operating revenue on our consolidated statements of operations.

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 16 - Variable Interest Entities. However, as the non-controlling interest associated with this lease arrangement generates book-tax differences, a deferred tax asset and liability have been recorded.

NOTE 15 – 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 or in the most advantageous market when no principal market exists. The fair value measurement 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, 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. Additionally, we use fair value to determine the inception value of our asset retirement obligations. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition, and would generally be classified in Level 3.

Executive Benefit Restoration Plan Trust

We have established 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 marketable securities are as follows (dollars in thousands):

	September 30, 2023		December 31, 2022	
	Cost	**Estimated Fair Value**	**Cost**	**Estimated Fair Value**
Marketable securities	$ 10,765	$ 10,022	$ 10,604	$ 9,808

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 fair values of our marketable securities are as follows (dollars in thousands):

	September 30, 2023		December 31, 2022	
	Cost	**Estimated Fair Value**	**Cost**	**Estimated Fair Value**
Marketable securities	$ 564	$ 507	$ 558	$ 489

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 $136.0 million as of September 30, 2023 and $101.8 million as of December 31, 2022.

Debt

The fair values of long-term debt, excluding amounts reclassified from short-term 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):

	September 30, 2023		December 31, 2022	
	Principal Amount	Estimated Fair Value	Principal Amount	Estimated Fair Value
Total long-term debt	$ 3,350,971	$ 2,969,014	$ 2,981,481	$ 2,725,606

NOTE 16 – 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):

	September 30, 2023	December 31, 2022
Net electric plant	$ 708,394	$ 721,997
Noncontrolling interest	131,742	126,180
Long-term debt	206,214	254,876
Accrued interest	2,387	7,400

Our consolidated statements of operations include the following Springerville Partnership expenses for the three and nine months ended September 30, 2023 and 2022 (dollars in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Depreciation, amortization and depletion	$ 4,535	$ 4,534	$ 13,603	$ 13,603
Interest	3,397	4,203	10,465	12,865

The revenue 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 non-controlling equity interest in the Springerville Partnership is reflected on our consolidated statements of operations.

NOTE 17 – LEGAL

Other than as disclosed below, we do not expect any litigation or proceeding pending or threatened against us to have a potential material effect on our financial condition, results of operations or cash flows.

FERC Tariffs: Because of increased pressure by states to regulate our rates and charges with impact in other states setting up untenable conflict, we sought consistent federal jurisdiction by FERC. This was accomplished with the addition of non-cooperative members in 2019, specifically MIECO, Inc., as a Non-Utility Member on September 3, 2019. On the same date, we became FERC jurisdictional for our Utility Members' rates, transmission service, and our market-based rates. We filed our tariff for wholesale electric service and transmission at FERC in December 2019.

On March 20, 2020, FERC issued orders regarding our our tariff filings. FERC's orders generally accepted our tariff filings and recognized that we became FERC jurisdictional on September 3, 2019, but did not make the tariffs retroactive to September 3, 2019. However, FERC specifically provided that no refunds are due on our Utility Members' rates and our transmission service rates prior to March 26, 2020. FERC also did not determine that our Utility Members' rates and transmission service rates were just and reasonable and ordered FPA section 206 proceedings to determine the justness and reasonableness of our rates and wholesale electric service contracts. On August 2, 2021, FERC approved our settlement agreement related to our Utility Member stated rate, as further discussed below. On March 7, 2022, FERC approved our settlement agreement related to our transmission service rates.

Petitions for review related to our tariff filings, including our Utility Members' rates, were filed with the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit Court of Appeals") by other parties. On October 17, 2023, an order was issued by the court to dismiss two of the petitions for review before the D.C. Circuit Court of Appeals as the parties filed motions to dismiss such cases. One petition for review by United Power, 20-1255, related to whether certain of our Board policies are required to be filed with FERC remains in abeyance. On October 13, 2023, an order was issued by the court directing the parties to file motions to govern future proceedings by November 3, 2023. On November 3, 2023, United Power filed an unopposed motion with the D.C. Circuit Court of Appeals to continue to hold the proceeding in abeyance. It is not possible to the outcome of this only remaining petition for review filed with the D.C. Circuit Court of Appeals.

On August 2, 2021, FERC approved our settlement agreement related to our Utility Member stated rate, including our wholesale electric service contracts and certain of our Board policies filed with FERC. With the exception of four reserved issues contingent on United Power, Inc. ("United Power") being a settling party, the settlement resolved all issues set for hearing and settlement procedures related to our Utility Members' rates. The settlement provided for us to implement a two-stage, graduated reduction in the charges making up our Class A rate schedule of two percent starting from March 1, 2021 until the first anniversary and four percent reduction (additional two percent reduction from then current rates) thereafter until the date a new Class A wholesale rate schedule is approved by FERC and goes into effect. We agreed to file a new Class A rate schedule after May 31, 2023 and prior to September 1, 2023. On June 16, 2023, we filed with FERC a new Class A rate schedule that uses a formula rate and requested for the new rate to take effect on January 1, 2024. On November 2, 2023, we filed a limited amendment to our new Class A rate schedule in response to FERC's August 15, 2023 Order on Initial Decision referenced below and reiterated our request for a January 1, 2024 effective date for the new rate schedule. Three of the reserved issues in the settlement agreement were related to the transmission component of our rates and the fourth relates to our community solar program. Additionally, with the exception of one reserved issue regarding transmission demand charges applicable to certain electric storage resources, each of the reserved issues had a prospective effect only, with the intent that any FERC rulings would be implemented in future rate filings.

A hearing on the four reserved issues occurred in March 2022 before an administrative law judge at FERC and an initial decision was issued by an administrative law judge on May 26, 2022. On June 26, 2022, we, United Power, and certain other Utility Members filed exceptions to the initial decision. On August 15, 2023, FERC issued an Order on Initial Decision that provides that we must also unbundle in our bills to our Utility Members our transmission and ancillary costs. Related to us directly assigning to our Utility Members the costs of our non-network radial facilities that do not meet FERC's standards for being included in our rolled-in transmission demand rate, FERC's order provided us flexibility in how we may justify that such costs should be allocated. In the order, FERC noted that we should perform an assessment of non-network transmission facilities and demonstrate that these facilities are eligible to be rolled into the transmission rate or should be direct assigned to our Utility Members. In addition, the FERC order provided that a portion of the reflected rate in our Board policy for community solar program was not just and reasonable, but the finding was without prejudice to further justification by us. With regard to the reserved issue concerning transmission demand charges applicable to certain electric storage resources, the FERC order agreed with our Board policy of billing Utility Members for the transmission demand costs that includes all of a Utility Member's transmission demand, including such Utility Member's electric storage resource. Northwest Rural Public Power District filed a motion for reconsideration with FERC, and that motion was denied by FERC by operation of law.

United Power's Adams District Court Complaint: On May 4, 2020, United Power filed a Complaint for Declaratory Judgement and Damages in the Adams County District Court, 2020CV30649, against us and our three Non-Utility Members. On July 2, 2021, the court granted United Power's motion to amend its May 2020 complaint to amend its claims as to our three Non-Utility Members and to add a claim that our addition of the Non-Utility Members violated Colorado law. On July 30, 2021, we filed a partial motion to dismiss a majority of United Power's claims. On July 30, 2021, the three Non-Utility Members filed a joint motion to dismiss all claims by United Power against the Non-Utility Members.

On March 23, 2022, the court issued an order regarding our and the Non-Utility Members' motions to dismiss. The court dismissed some of the claims against us and the Non-Utility Members, including the civil conspiracy claim. After the dismissal, the remaining claims included seeking declaratory orders that the addition of the Non-Utility Members violated Colorado law and our Articles of Incorporation and Bylaws, the April 2019 Bylaws amendment that allows our Board to establish one or more classes of membership in addition to the then existing all-requirements class of membership was procured through fraud or misrepresentation and is void, and the April 2020 Board approvals related to the methodology to calculate a contract termination payment and buy-down payment formula do not apply to United Power and are void, and that we have breached our Bylaws and our wholesale electric service contract with United Power.

On April 6, 2022, we and each Non-Utility Member filed their respective answers to the first amended complaint denying that United Power is entitled to any relief and requesting the court enter judgment of dismissal. We also requested declaratory judgements that the April 2019 Bylaws amendment and the April 2020 Board approvals related to the methodology to calculate a contract termination payment and buy-down payment formula are valid. On April 27, 2022, United Power filed a reply asserting that we are not entitled to any relief on our requests for declaratory judgements. In United Power's February 2023 expert report, United Power asserts that its damages are in the range of $483 million to $533 million, plus interest after the date of the expert report.

On March 27, 2023, we filed a motion for summary judgement seeking for the court to enter judgement for us on all of United Power's remaining claims. On July 28, 2023, the court issued an order on our motion for summary judgement. The court found that our addition of the Non-Utility Members did not violate Colorado law or our Bylaws and granted summary judgement in our favor on the claim that our April 2019 Bylaw amendment was procured through fraud or misrepresentations, but our April 2019 Bylaw amendment is void because it conflicted with our Articles of Incorporation at the time of such amendment. On November 1, 2023, our Board ratified our existing Bylaws, including all amendments and restatements of the Bylaws since April 2019, and affirmed and ratified the three Non-Utility Members as Non-Utility Members of us as of their respective original date of admission.

On October 24, 2023, during a status conference, the court scheduled a 12-day jury trial to start on January 16, 2024. On November 1, 2023, we and United Power 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 Adams County District Court after the parties execute a formal settlement agreement and other agreements related to power and asset sales to United Power. The parties are to cooperate to execute the formal settlement agreement and related agreements no later than December 8, 2023.

It is not possible to predict the outcome of this matter, whether the litigation will be dismissed or whether we will incur any liability in connection with this matter, and in the event of liability, if any, the amount or type of damages, equitable relief or other legal relief that could be awarded or granted.

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 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 our 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 October 31, 2023, the final briefs were filed in this consolidated proceeding. 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.

NOTE 18 – SUBSEQUENT EVENT

As disclosed in Note 17 - Legal, we executed a settlement Term Sheet with United Power on November 1, 2023. The Term Sheet sets forth terms for the two utilities to cooperate to execute a formal settlement agreement and related agreements by December 8, 2023, involving power purchases and the sale of utility assets from us to United Power.

Item 2. 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-five Members. We have three classes of membership: Class A - utility full requirements members, Class B - utility partial requirements members, and non-utility members. For our forty-two Class A members, we provide electric power pursuant to long-term wholesale electric service contracts. We currently have no Class B members, and therefore all our Utility Members are currently Class A members. We have three Non-Utility Members. Thirty-eight 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 became regulated as a public utility under Part II of the FPA on September 3, 2019 when we admitted a Non-Utility Member, MIECO, Inc. (a non-governmental/non-electric cooperative entity), as a new Member/owner.

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 4,355 MWs, of which approximately 1,366 MWs comes from renewables.

We sold 13.8 million MWhs for the nine months ended September 30, 2023, of which 91.1 percent was to Utility Members. Total revenue from electric sales was $1.036 billion for the nine months ended September 30, 2023 of which 89.2 percent was from Utility Member sales. Our results for the nine months ended September 30, 2023 were primarily impacted by cool and unusually wet spring weather conditions from May through August, as well as lower availability from our coal-fired generating facilities which resulted in lower energy sales, lower rate stabilization measures and increased production costs.

- Utility Member electric sales decreased $7.3 million during the nine months ended September 30, 2023 compared to the same period in 2022 primarily due to the cooler, wetter weather between May and August compared to the prior year, as well as the decrease in our Utility Members' stated rate in March 2022 as part of the 2021 settlement agreement related to our Utility Members' stated rate. The cooler, wetter weather during this timeframe resulted in less irrigation load, reduced cooling needs and overall less power consumption in our Utility Members' service territories. The decrease in lower load due to the impact of weather was partially offset by load growth.

- Production expense increased $14.6 million, or 11.4 percent, primarily due to higher maintenance costs at certain generating facilities resulting from maintenance outages at those facilities.

- Fuel expense decreased $27.6 million, or 12.2 percent, primarily due to lower generation from our coal-fired generating facilities. The lower generation resulted from maintenance outages and short-term market prices being below our generating costs, therefore, more power was purchased in the market. Additionally, the average rate for gas was 46.4 percent lower during the nine months ended September 30, 2023 compared to the same period in 2022.

Our Bylaws and 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, at least 95 percent of its electric power requirements from us. Our wholesale electric service contracts with our 42 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 September 30, 2023, 21 Utility Members have enrolled in this program with capacity totaling approximately 141 MWs of which 138 MWs are in operation.

In 2020, we filed with FERC a buy-down payment methodology tariff and our Board policy to implement a partial requirements structure. Under the new partial requirements membership construct, Utility Members could request to self-supply up to approximately 50 percent of their load requirements, subject to availability in the open season, in addition to the current 5 percent self-supply provision under the wholesale electric service contract and the community solar program. A Utility Member that chose the partial requirements options would be obligated to make a buy-down payment to us. During our partial requirements "open season," a total of six Utility Members were allocated an aggregate of 300 MWs of self-supply.

The buy-down payment methodology tariff and Board policy were accepted by FERC, subject to refund, and FERC referred it to FERC's hearing and settlement procedures. In June 2023, we filed with FERC a notice of cancellation of the buy-down payment methodology tariffs and Board policy to be effective August 28, 2023, stating such tariff and policy should no longer be a mechanism for Utility Members to self-supply a portion of their load requirements. In August 2023, FERC accepted our notice of cancellation. We and our Utility Members continue to evaluate a buy-down payment methodology that may be re-filed with FERC.

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. The modified contract termination payment methodology is designed to protect the financial interests of our remaining Utility Members should a Utility Member elect to withdraw from membership in us. Our September 2021 tariff filing includes requirements for a two-year notice and the payment of a contract termination payment to us. In simple terms, our modified contract termination payment amount is the greater of (i) the withdrawing Utility Member's debt covenant obligation, and (ii) 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. The Utility Member's debt covenant obligation is its *pro rata* share of our total debt and other obligations. 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. On September 29, 2022, the administrative law judge issued an initial decision, which determined that the different contract termination payment methodologies by United Power, certain of our other Utility Members, and us were not just and reasonable. The administrative law judge endorsed the FERC trial staff methodology, with significant adjustments suggested by us. The administrative law judge's initial decision favorably discusses the concept of rate-neutrality to our remaining Utility Members and stated that the FERC trial staff's proposal, with our recommended changes, "appears to achieve an exit fee close to that of" our debt covenant obligation set forth in our contract termination payment methodology tariff. The judge's initial decision did not include a contract termination payment number. We and United Power have differing positions on the contract termination payment number based upon the initial decision, with United Power's number much lower. In October 2022, we, United Power, certain other Utility Members, and other parties filed exceptions to the initial decision. Because exceptions were taken to the initial decision, the initial decision and exceptions are pending before the Commissioners of FERC for a decision. For further information see "Item 1 – BUSINESS – MEMBERS - Relationship with Members" in our annual report on Form 10-K for the year ended December 31, 2022.

On April 29, 2022, both United Power and Northwest Rural Public Power District provided us notices to withdraw from membership in us, with a May 1, 2024 withdrawal effective date. In January 2023, Mountain Parks Electric, Inc. provided us a notice to withdraw from membership in us, with a February 1, 2025 withdrawal effective date. In September 2023, we filed with FERC an unexecuted Withdrawal Agreement with United Power. While United Power and us negotiated and agreed to most of the terms of the Withdrawal Agreement, the parties agreed that we should file the Withdrawal Agreement on an unexecuted basis such that FERC may resolve the limited issues on which the parties could not agree. The Withdrawal Agreement describes the practical action items and related rights and obligations of the parties involved with effectuating the withdrawal of United Power from membership in us. In October 2023, United Power filed its protest related to the Withdrawal Agreement, including an alternative agreement that it proposes. We subsequently filed an answer to United Power's protest. Nine other Utility Members also filed answers disagreeing with certain provisions in United Power's alternative agreement and United Power's requests in its protest.

In July 2021, United Power's first amended complaint for declaratory judgement and damages against us and our Non-Utility Members was deemed filed in Adams County District Court alleging, among other things, that the April 2019 Bylaws amendment that allows our Board to establish one or more classes of membership in addition to the then existing all-requirements class of membership is void and that we have breached our Bylaws and our wholesale electric service contract with United Power. A jury trial is scheduled to start on January 16, 2024. In November 2023, we and United Power executed a settlement Term Sheet. The parties agreed to a mutual release of claims, and to file a stipulation of dismissal, with prejudice, of the litigation pending in Adams County District Court after the parties execute a formal settlement agreement and other agreements related to power and asset sales to United Power. See Note 17 to the Unaudited Consolidated Financial Statements in Item 1 for further information.

Responsible Energy Plan and Colorado Electric Resource Plan

Responsible Energy Plan

In July 2019, our Board established that we would pursue a transition to a cleaner energy portfolio by developing a Responsible Energy Plan. In January 2020, we released our Responsible Energy Plan. With our Responsible Energy Plan, we are implementing a clean energy transition while being responsible to our employees, Members, communities, and environment. The plan was developed with input from our Board, our Utility Members and external stakeholders. Our plan is dynamic and will change as Utility Members' needs change, new technologies become available and market conditions evolve. We and our Utility Members have made great strides implementing the plan, which has allowed us to set new goals beyond those identified in January 2020. Some of the highlights of the Responsible Energy Plan include:

- eliminating all emissions from our coal-fired generating facilities in Colorado and New Mexico by 2030.
- by 2025, 50 percent of the electricity our Utility Members use is expected to come from clean energy.
- more local renewables for Utility Members through contract flexibility.
- promoting participation in a regional transmission organization.
- expanding electric vehicle infrastructure and beneficial electrification.

For further information regarding our Responsible Energy Plan, see "Item 1 – BUSINESS — MEMBERS – Responsible Energy Plan" in our annual report on Form 10-K for the year ended December 31, 2022.

Colorado Electric Resource Plan

In December 2020, we filed our first Phase I Electric Resource Plan under COPUC rules related to electric resource plans, which contained our Preferred Plan. In September 2021, we submitted to the COPUC our Revised Preferred Plan in connection with Phase I of our 2020 Electric Resource Plan that modeled resources during the resource acquisition period of 2021 to 2030. In January 2022, we reached a comprehensive settlement agreement that was filed with the COPUC for approval. In March 2022, the administrative law judge for the COPUC recommended approval of the settlement agreement and the approval became effective in April 2022. The settlement agreement sets emissions reduction targets for 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. For further information, see "Item 1 – BUSINESS — POWER SUPPLY RESOURCES – Resource Planning" in our annual report on Form 10-K for the year ended December 31, 2022.

In May 2022, we began Phase II of our 2020 Electric Resource Plan with the issuance of a request for proposals for capacity and energy bids, with a focus on projects that support emissions reductions. In February 2023, we filed our 2020 Electric Resource Plan Phase II implementation report identifying our preferred portfolio for resource acquisitions in the 2025-2026 timeframe. The Phase II modeling filed with the COPUC indicated selection of a 200 MW new wind resource for 2026, subject to COPUC approval. A COPUC decision on Phase II of the 2020 Electric Resource Plan was issued in June 2023 approving the new wind resource acquisition; however, in July 2023, we submitted a filing notifying the COPUC that the developers for both the selected bid and back-up wind bid would not honor their original prices. We will seek new resources for 2026 as part of the Phase II solicitation for the 2023 Electric Resource Plan. Our notice filing also identified new bid policy measures are under consideration to further safeguard against the risk of similar bidder actions in the future. Our Phase I 2023 Electric Resource Plan filing is due to the COPUC on December 1, 2023.

Other Recent Developments

In September 2023, we submitted a Letter of Interest to apply for funding through the U.S. Department of Agriculture's Empowering Rural America (New ERA) Program. If granted, we expect the funding will lead to significant reductions in our greenhouse gas emissions, the addition of clean energy sources, and relief from stranded assets, that we expect will assist us in providing affordable wholesale rates and reliable power to our Utility Members. Our proposal aims to transform our system, enhance grid resiliency, and secure a federal investment for a clean energy transformation benefiting our Utility Members across multiple states. Following U.S. Department of Agriculture's review of our submission, we hope to receive an invitation to proceed to complete the full New ERA Program application. The New ERA Program implements the $9.7 billion funded in the Inflation Reduction Act of 2022.

In September 2023, we announced our commitment, along with six other western utilities, to become a full member of the Southwest Power Pool regional transmission organization expansion into the Western Interconnection. We expect the expansion of Southwest Power Pool's service territory from the Eastern Interconnection into the Western Interconnection to be completed in early 2026 at which time certain of our load and transmission facilities in the Western Interconnection will be part of the Southwest Power Pool regional transmission organization. Our load and transmission facilities in the Eastern Interconnection, largely in Nebraska, have been in the Southwest Power Pool regional transmission organization since 2016.

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. As of September 30, 2023, there were no material changes in our critical accounting policies as disclosed in our annual report on Form 10-K for the year ended December 31, 2022.

Factors Affecting Results

Master Indenture

As of September 30, 2023, we had approximately $3.15 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. Our Master Indenture requires us to establish 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 historical and pro forma basis. Our Master Indenture also requires us to maintain an ECR of at least 18 percent at the end of each fiscal year. Pursuant to our Master Indenture, 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.

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. To date, we have retired approximately $493.2 million of patronage capital to our Members.

Pursuant to our Board Policy for Financial Goals and Capital Credits, we have historically set rates to achieve a DSR and ECR in excess of the requirements under our Master Indenture in order to mitigate the risk of potential negative variances between budgeted margins and actual margins. Our Board approved rates to our Utility Members for 2023 to achieve a DSR and ECR in excess of the requirements under our Master Indenture, including a DSR of 1.112 based on our 2023 budget. Based on our 2023 budget, we have forecasted the recognition of the remaining balance of previously deferred membership withdrawal income during 2023. As discussed further below, in June 2023, we filed with FERC a new Class A rate that uses a formula rate and requested for the new rate to take effect on January 1, 2024. We anticipate FERC will accept, subject to refund, this Class A formula rate filing during the fourth quarter of 2023, at which time we intend to reverse the approximate $44 million of environmental obligation expense 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. This reversal is expected to have a positive impact on our DSR for 2023 and we forecast, with such reversal, that our DSR for the twelve months ended December 31, 2023 will be in excess of the requirements under our Master Indenture, subject to actual results differing materially from our assumptions for the fourth quarter.

Rates and Regulation

On September 3, 2019, we became FERC jurisdictional for our Utility Members' 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, 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. On August 2, 2021, FERC approved our settlement agreement related to our Utility Members' stated rate that provides for us to implement a two-stage, graduated reduction in the charges making up our A-40 rate of two percent starting from March 1, 2021 until the first anniversary and four percent reduction (additional two percent reduction from then current rates) on March 1, 2022 until the date a new Class A wholesale rate schedule goes into effect. See Note 17 to the Unaudited Consolidated Financial Statements in Item 1 for further information.

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.

Revenues from electric power sales to our Utility Members are primarily from our Class A wholesale rate schedule filed with FERC that is a stated rate. In 2022 and 2023, our Class A rate schedule (A-40) for electric power sales to our Utility Members consist of three billing components: an energy rate and two demand rates. Utility Members' rates for energy and demand are 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 rate was billed based upon a price per kWh of physical energy delivered and the two demand rates (a generation demand and a transmission/delivery demand) were both billed based on the Utility Member’s highest thirty-minute integrated total demand measured in each monthly billing period during our peak period from noon to 10:00 pm daily, Monday through Saturday, with the exception of six holidays.

As part of the settlement agreement for our Utility Members' stated rate, we 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. On June 16, 2023, we filed with FERC the new Class A rate schedule (A-41) that uses a formula rate and requested for the new rate to take effect on January 1, 2024. Our proposed formula rate is designed to collect our projected annual revenue requirements, including Board-approved margins, with an annual true-up mechanism to ensure that the revenue collected accurately reflects our actual costs incurred. The rate template will be updated annually with the next year’s budget and then trued up to actuals annually after the end of each rate year. The formula rate is designed for annual rate adjustments to account for variations in load and costs without additional FERC approval for each annual adjustment. The new rate components are similar to the existing Class A rate schedule (A-40) with a few exceptions. The exceptions include a further unbundling of our transmission/delivery demand rate into two demand components, one for network transmission costs and another for non-network transmission costs. This change does not shift costs or change the overall transmission bill. It provides transparency to Utility Members to see what components of transmission are driving costs. Another rate change is from the average and excess demand method to a peaker methodology, with the peaker methodology setting a demand charge set to reflect the cost of an additional peaking generating facility. This method provides a pricing signal to Utility Members to manage peak usage by creating credits for peak shifting equal to the cost of a peaking generating facility rather the full system demand cost. An additional major change in the rate was the addition of a new financial metric for margin calculation. In addition to a minimum DSR of at least 1.15 and ECR of at least 20 percent at the end of each fiscal year, the rate uses a $20 million margin minimum to assure financial resources are available. A majority of our Utility Members and other parties have intervened in our rate filing with FERC. Certain of these Utility Members filed comments with FERC in support of our filing. Six of our Utility Members filed a protest, but three of such protesting Utility Members also asked FERC to conditionally accept the rate, subject to refund and hearing and settlement procedures. We filed an answer with FERC on July 28, 2023 related to such protests. On November 2, 2023, we filed a limited amendment with FERC to our new Class A rate schedule in response to FERC's August 15, 2023 Order on Initial Decision related to the four reserved issues concerning our Utility Members' stated rate. The limited amendment addressed the reserved issue of unbundling costs in our bills to our Utility Members, in particular ancillary costs, and the reserved issue related to cost allocation of non-networked transmission facilities. In our limited amendment, we reiterated our request for a January 1, 2024 effective date for the new rate schedule and requested FERC to take action by December 31, 2023. We anticipate FERC will accept, subject to refund, our Class A formula rate during the fourth quarter of 2023.

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. We anticipate FERC will accept, subject to refund, this Class A formula rate filing during the fourth quarter of 2023, at which time we intend to reverse the approximate

$44 million of environmental obligation expense that was recorded in 2022 as a regulatory asset to be amortized to expense over 25 years and recovered from our Utility Members through rates.

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. Under the normalization method, changes in deferred tax assets or liabilities result in deferred income tax expense (benefit) and any recorded income tax expense (benefit) therefore includes both the current income tax expense (benefit) and the deferred income tax expense (benefit). Our subsidiaries are not subject to FERC regulation and continue to use a 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 sold at market prices after consideration of incremental production costs. Demand billings 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 our 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.

Impacts of Supply Chain and Inflation

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 and supply chain disruptions.

Three Months Ended September 30, 2023 Compared to Three Months Ended September 30, 2022

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, and coal sales. 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 MWh by type of purchaser for the three months ended September 30, 2023 and 2022 (dollars in thousands):

	Three Months Ended September 30,		Period-to-period Change	
	2023	2022	Amount	Percent
Operating revenues				
Utility Member electric sales	$ 357,576	$ 362,442	$ (4,866)	(1.3)%
Non-member electric sales	51,294	55,669	(4,375)	(7.9)%
Rate stabilization	14,041	32,950	(18,909)	(57.4)%
Provision for rate refunds	(210)	(2,039)	1,829	(89.7)%
Other	15,618	16,971	(1,353)	(8.0)%
Total operating revenues	**$ 438,319**	**$ 465,993**	**$ (27,674)**	(5.9)%
Energy sales (in MWh):				
Utility Member electric sales	4,730,452	4,870,701	(140,249)	(2.9)%
Non-member electric sales	608,201	614,436	(6,235)	(1.0)%
	5,338,653	**5,485,137**	**(146,484)**	(2.7)%

- Utility Member electric sales revenue decreased primarily due to cooler, wetter weather during the three months ended September 30, 2023 compared to the same period in 2022. The cooler, wetter weather resulted in less irrigation load, reduced cooling needs and overall less energy sales to our Utility Members.
- Non-member electric sales revenue decreased primarily due to lower long-term sales and lower average prices. Long-term sales decreased 77,990 MWhs, or 40.6 percent, to 113,879 MWhs for the three months ended September 30, 2023 compared to 191,869 MWhs for the same period in 2022. Average prices decreased 6.9 percent for the three months ended September 30, 2023 compared to the same period in 2022.
- Rate stabilization represents recognition of income from the withdrawal of former Utility Members from membership in us that was previously deferred in accordance with accounting requirements related to regulated operations. We recognized $14.0 million of previously deferred membership withdrawal income during the three months ended September 30, 2023 compared to $33.0 million of previously deferred membership withdrawal income during the same period in 2022 as part of our rate stabilization measures. We expect to recognize additional previously deferred membership withdrawal income during the remainder of 2023.

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 the three months ended September 30, 2023 and 2022 (dollars in thousands):

	Three Months Ended September 30,		Period-to-period Change	
	2023	2022	Amount	Percent
Operating expenses				
Purchased power	$ 120,250	$ 128,202	$ (7,952)	(6.2)%
Fuel	71,241	94,770	(23,529)	(24.8)%
Production	44,758	40,045	4,713	11.8 %
Transmission	47,098	47,054	44	0.1 %
General and administrative	19,663	18,658	1,005	5.4 %
Depreciation, amortization and depletion	43,120	46,604	(3,484)	(7.5)%
Coal mining	3,834	1,814	2,020	111.4 %
Other	2,345	2,288	57	2.5 %
Total operating expenses	**$ 352,309**	**$ 379,435**	**$ (27,126)**	(7.1)%

- Purchased power expense decreased primarily due to lower average prices of 16.6 percent during the three months ended September 30, 2023 compared to the same period in 2022, with an offsetting increase of 311,168 MWhs purchased during the three months ended September 30, 2023 compared to the same period in 2022. With short-term market prices being below our generating costs, more power was purchased in the market during the three months ended September 30, 2023, therefore, generation by our coal-fired generating facilities was lower during the same period.
- Fuel expense decreased primarily due to a decrease in average rate for natural gas of 54.9 percent, a decrease of 38,216 MWhs in generation by our natural gas-fired generating facilities, and a decrease of 530,782 MWhs in generation by our coal-fired generating facilities, partially offset by a higher average rate of 37.3 percent.

Nine Months Ended September 30, 2023 Compared to Nine Months Ended September 30, 2022

Operating Revenues

The following is a comparison of our operating revenues and energy sales in MWh by type of purchaser for the nine months ended September 30, 2023 and 2022 (dollars in thousands):

	Nine Months Ended September 30,		Period-to-period Change	
	2023	2022	Amount	Percent
Operating revenues				
Utility Member electric sales	$ 923,977	$ 931,257	$ (7,280)	(0.8)%
Non-member electric sales	111,729	110,029	1,700	1.5 %
Rate stabilization	36,862	58,295	(21,433)	(36.8)%
Provision for rate refunds	94	759	(665)	(87.6)%
Other	48,162	42,817	5,345	12.5 %
Total operating revenues	**1,120,824**	**1,143,157**	**$ (22,333)**	(2.0)%
Energy sales (in MWh):				
Utility Member electric sales	12,526,839	12,585,009	(58,170)	(0.5)%
Non-member electric sales	1,228,853	1,469,305	(240,452)	(16.4)%
	13,755,692	**14,054,314**	**(298,622)**	(2.1)%

- We recognized $36.9 million of previously deferred membership withdrawal income during the nine months ended September 30, 2023 compared to $58.3 million of previously deferred non-member electric sales revenue during the same period in 2022. We expect to recognize additional previously deferred membership withdrawal income during the remainder of 2023.
- Other operating revenue increased primarily due to coal sales to third parties and the sale of excess intangible assets.

Operating Expenses

The following is a summary of the components of our operating expenses for the nine months ended September 30, 2023 and 2022 (dollars in thousands):

	Nine Months Ended September 30,		Period-to-period Change	
	2023	2022	Amount	Percent
Operating expenses				
Purchased power	316,356	321,240	$ (4,884)	(1.5)%
Fuel	197,944	225,491	(27,547)	(12.2)%
Production	142,733	128,095	14,638	11.4 %
Transmission	142,406	136,289	6,117	4.5 %
General and administrative	61,738	57,824	3,914	6.8 %
Depreciation, amortization and depletion	128,191	133,347	(5,156)	(3.9)%
Coal mining	9,603	7,189	2,414	33.6 %
Other	11,057	50,626	(39,569)	(78.2)%
Total operating expenses	**$ 1,010,028**	**$ 1,060,101**	**$ (50,073)**	(4.7)%

- Fuel expense decreased due to a decrease in average rate for natural gas of 46.4 percent, partially offset by an increase of 467,253 MWhs in generation by our natural gas-fired generating facilities, and a decrease of 1,432,462 MWhs in generation by our coal-fired generating facilities, partially offset by a higher average rate of 36.8 percent.
- Production expense increased due to higher maintenance expenses of $19.3 million for the nine months ended September 30, 2023 compared to the same period in 2022.
- Other operating expenses decreased primarily due to the recording of an additional environmental obligation of $44.9 million during the second quarter of 2022 related to revised cost estimates at New Horizon Mine. We anticipate FERC will accept, subject to refund, our Class A formula rate filing during the fourth quarter of 2023, at which time we intend to reverse the approximate $44 million of environmental obligation expense that was recorded in 2022.

Financial Condition as of September 30, 2023 Compared to December 31, 2022

The principal changes in our financial condition from December 31, 2022 to September 30, 2023 were due to increases and decreases in the following:

Assets

- Construction work in progress increased $64.8 million, or 79.4 percent, to $146.4 million as of September 30, 2023 compared to $81.6 million as of December 31, 2022. The increase was due to capital expenditures of $113.5 million, primarily capital projects at Springerville Unit 3, migrating and upgrading software systems to hosted solutions and various transmission upgrade projects, partially offset by transfers to electric plant in service for completed projects of $48.6 million.
- Cash and cash equivalents increased $61.8 million, or 58.4 percent, to $167.7 million as of September 30, 2023 compared to $105.9 million as of December 31, 2022. The increase was primarily due to $300 million of Term SOFR rate loans under the 2022 Revolving Credit Agreement, a $150 million draw on the syndicated multiple advance term loan with CoBank and an increase in deposits associated with generator interconnection requests. These increases in cash and cash equivalents were partially offset by the pay down of all commercial paper in June 2023 and an increase in capital expenditures.
- Restricted cash and investments-current increased $16.8 million to $17.4 million as of September 30, 2023 compared to $0.6 million as of December 31, 2022. The increase was primarily due to $16.9 million that was deposited with our Master Indenture Trustee in September 2023 in advance of our October 1, 2023 debt service payments for the 2014 Private Placement and Moffat County Pollution Control Bonds. In accordance with our Master Indenture, we are required to fund the account one day prior to debt service payments.
- Coal inventory increased $16.9 million, or 48.7 percent, to $51.6 million as of September 30, 2023 compared to $34.7 million as of December 31, 2022. The increase was primarily due to receiving more coal than was consumed as a result of lower generation and maintenance outages at Craig Generating Station. Additionally, coal inventory increased at Springerville Unit 3 as delivery issues were resolved and inventory was returned to normal levels.

- Materials and supplies increased $9.5 million, or 10.2 percent, to $103.0 million as of September 30, 2023 compared to $93.5 million as of December 31, 2022. The increase was primarily due to the disruption in the global supply chain for the procurement and delivery of inventory-related items and generally higher prices to purchase these items.

Liabilities

- Long-term debt increased $69.3 million, or 2.4 percent, to $2.939 billion as of September 30, 2023 compared to $2.870 billion as of December 31, 2022 and current maturities of long-term debt increased $300.9 million, or 323.9 percent, to $393.8 million as of September 30, 2023 compared to $92.9 million as of December 31, 2022. The total increase of $370.2 million was primarily due to $300 million of Term SOFR rate loans under the 2022 Revolving Credit Agreement and a $150 million draw on the syndicated multiple advance term loan with CoBank. These debt issuances were used to support liquidity and capital projects.
- Short-term borrowings decreased $274.0 million to $100,000 as of September 30, 2023 compared to $274.1 million as of December 31, 2022. The decrease was due to the pay down of all commercial paper in June 2023, which was funded by $300 million of Term SOFR rate loans under the 2022 Revolving Credit Agreement. Additionally, in June 2023, we acquired land in the amount of $600,000. Of the total purchase, $100,000 is due within 12 months and is included in short-term borrowings and the remaining balance is payable in equal annual amounts to 2029 and is included in long-term debt.
- Regulatory liabilities decreased $37.2 million, or 74.5 percent, to $12.7 million as of September 30, 2023 compared to $49.9 million as of December 31, 2022. The decrease was primarily due to the recognition of $36.9 million of previously deferred membership withdrawal income.

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 September 30, 2023, we had $167.7 million in cash and cash equivalents. Our committed credit arrangement as of September 30, 2023 is as follows (dollars in thousands):

	Authorized Amount		Available September 30, 2023	
2022 Revolving Credit Agreement	$ 520,000	(1)	$ 220,000	(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 at September 30, 2023 was $300 million which was dedicated to $300 million of Term SOFR loans under our 2022 Revolving Credit Agreement.

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, $75 million of the letter of credit sublimit, and $220 million of the commercial paper back-up sublimit remained available as of September 30, 2023.

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 (1.125 percent as of September 30, 2023) based on our credit ratings. Base rate loans bear interest at the alternate base rate plus a margin (0.125 percent as of September 30, 2023) 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 (1.125 percent as of September 30, 2023) based on our credit ratings.

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 September 30, 2023, thereby providing 100 percent dedicated support for any commercial paper outstanding. As of September 30, 2023, we had no commercial paper outstanding and $220 million available on the commercial paper back-up sublimit. See Note 7 to the Unaudited Consolidated Financial Statements in Item 1 for further information.

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, additional tender offers, or otherwise and may continue to seek to retire or purchase our outstanding debt in the future. 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 is aligned with our business and the long-term health of our company.

We believe we have sufficient liquidity to fund operations and capital financing needs from projected cash on hand, our commercial paper program, and the 2022 Revolving Credit Agreement.

Cash Flow

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

Nine Months Ended September 30, 2023 Compared to Nine Months Ended September 30, 2022

Operating activities. Net cash provided by operating activities was $104.7 million for the nine months ended September 30, 2023 compared to $125.8 million for the same period in 2022, a decrease in net cash provided by operating activities of $21.1 million. The decrease in net cash provided by operating activities was impacted by the timing of payment of trade payables and accrued expenses, the timing of cash collected from Member accounts receivable and deposits related to interconnection customers.

Investing activities. Net cash used in investing activities was $117.0 million for the nine months ended September 30, 2023 compared to $88.6 million for the same period in 2022, an increase in net cash used in investing activities of $28.4 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.

Financing activities. Net cash provided by financing activities was $90.5 million for the nine months ended September 30, 2023 compared to net cash used in financing activities of $14.1 million for the same period in 2022, an increase in net cash provided by financing activities of $104.6 million. The increase in net cash provided by financing activities was primarily due to the issuance of $450 million of long-term debt to support liquidity and capital expenditures partially offset by a decrease in short-term borrowings for the nine months ended September 30, 2023 compared to the same period in 2022.

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. After taking into account our Responsible Energy Plan, in the years 2023 through 2027, we forecast that we may invest approximately $997 million in new facilities and upgrades to our existing facilities.

Our actual capital expenditures depend on a variety of factors, including assumptions related to our Responsible Energy Plan and our Revised Preferred Plan in conjunction with Phase I of our 2020 Electric Resource Plan approved by the COPUC, federal funding under the New ERA Program and other federal programs, Utility Member load growth or Utility Member withdraws, partial requirements, availability of necessary permits, regulatory changes, environmental requirements, construction delays and costs, supply chain issues, inflation, 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 service area.

Changing Environmental Regulations

We are subject to various federal, state and local laws, rules and regulations with regard to air quality, including greenhouse gases, water quality, and other environmental matters. These environmental laws, rules and regulations are complex and change frequently. Following are updates on recent developments that may impact us.

Air Quality

Transport Rule. 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 air quality in downwind states that are working to attain the 2015 8-hour ozone National Ambient Air Quality Standard. The final rule requires significant nitrogen oxide reductions and associated expenditures for selective catalytic reduction technology. Based on updated modeling that shows Wyoming would not contribute significantly to downwind states' air quality issues, the EPA withdrew Wyoming from the applicability of the final rule, therefore Laramie River Station is unaffected. At the same time that the EPA finalized their transport rule, the EPA announced a further evaluation of emissions modeling for several states, including Arizona and Springerville Generating Station. The EPA is expected to finalized its further consideration of Arizona and other states by the end of 2023.

Water Quality

Waters of the United States. In May 2023, the United States Supreme Court ruled in *Sackett v. Environmental Protection Agency* to define waters of the United States and therefore waters that are subject to regulation under the Clean Water Act. The Supreme Court's ruling decreases the jurisdictional reach under the Clean Water Act that may be claimed by EPA and the U.S. Army Corps of Engineers. Federal agencies issued a direct final rule, effective September 8, 2023, to align regulations with the ruling. Relatedly, Colorado initiated development of a state program to regulate dredge and fill activities in state waters. Until these state activities develop further, the impacts on us remain uncertain.

For further discussion regarding potential effects on our business from environmental regulations, see "Item 1 – BUSINESS — ENVIRONMENTAL REGULATION" and "Item 1 – RISK FACTORS" in our annual report on Form 10-K for the year ended December 31, 2022 and "Item 2 - MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS" in our quarterly report on Form 10-Q for the quarterly period ended June 30, 2023.

Rating Triggers

Our current senior secured ratings are "A3 (negative outlook)" by Moody's, "BBB (negative outlook)" by S&P, and "A- (stable 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. 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 3. Quantitative and Qualitative Disclosures About Market Risk

There have been no material changes to market risks during the most recent fiscal quarter from those reported in our annual report on Form 10-K for the year ended December 31, 2022.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this 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 our disclosure controls and procedures were not effective due to a material weakness in internal control over financial reporting as described below.

A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting such that there is more than a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis. The following material weakness was identified: During the quarter ending December 31, 2022, a material weakness in our controls related to the accounting for asset retirement and environmental reclamation obligations for coal mines was identified. Notwithstanding the material weakness, management, including our principal executive officer and principal financial officer, believes the consolidated financial statements included in this Form 10-Q fairly represent, in all material respects, our financial condition, results of operations and cash flows at and for the periods presented in accordance with GAAP.

Remediation

With these issues identified, we have evaluated and have implemented the following remediation action steps to ensure that the control deficiencies contributing to the material weakness are remediated with final testing of such remediation action steps to evaluate their effectiveness to occur later this year:

- Established separate accounts for each mine pit in order to segregate each related asset retirement obligation into its own individual account.
- Established procedures to perform monthly rollforward schedules for each asset retirement and environmental reclamation obligation and utilize those rollforward schedules in the monthly account reconciliation process to identify issues on a more timely basis.
- Established a calculation model which will only be used for a mine pit in final reclamation in order to more accurately adjust the remaining obligation.
- Implemented quarterly meetings between management and staff in order to review both the asset retirement and environmental reclamation obligations.

Changes in Internal Controls

Other than those described above, there were no changes in our internal controls over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Information required by this Item is contained in Note 17 to the Unaudited Consolidated Financial Statements in Item 1.

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 quarterly report on Form 10-Q.

Item 6. Exhibits

Exhibit Number	Description of Exhibit
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 Patrick L. Bridges (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 Patrick L. Bridges (Principal Financial Officer).
95	Mine Safety Disclosure Exhibit.
101	XBRL Interactive Data File.

SIGNATURES

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

Tri-State Generation and Transmission
Association, Inc.

Date: November 9, 2023	By: /s/ Duane Highley Duane Highley Chief Executive Officer
Date: November 9, 2023	/s/ Patrick L. Bridges Patrick L. Bridges Senior Vice President/Chief Financial Officer (Principal Financial Officer)